NO. 3 BIOMASS BOILER PSD PERMIT APPLICATION
VOLUME I
GRAPHIC PACKAGING INTERNATIONAL, INC. ▪ MACON, GEORGIA

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1. EXECUTIVE SUMMARY

Graphic Packaging International, Inc. (GPI) owns and operates an integrated pulp and paper mill (Macon Mill) in Macon, Bibb County, Georgia. The Macon Mill is a major stationary source as defined in the Georgia Rules for Air Quality Control (GRAQC) 391-3-1-.03(10). The facility currently operates under Part 70 Operating Permit No. 2631-021-0001-V-03-0 issued by the Georgia Environmental Protection Division (EPD), effective March 10, 2008. GPI is proposing modifications to the Macon Mill that will expand utilization of biomass energy, allow the mill to be largely self-sufficient from an electrical power generation standpoint, and substantially reduce reliance on coal combustion. This application package contains the necessary state air construction permit application and Title V operating permit modification elements related to the proposed project.

1.1 PROPOSED PROJECT

GPI is proposing to install a new bubbling fluidized bed (BFB) boiler (No. 3 Biomass Boiler) at the Macon Mill. The proposed biomass boiler will be equipped with flue gas recirculation, a baghouse, and a selective non-catalytic reduction (SNCR) system for emissions control. In addition, GPI is potentially considering utilizing duct sorbent injection for acid gas emissions control. The boiler, to be rated at approximately 620 MMBtu/hr heat input, will be designed to combust a variety of fuels. The primary fuel will be biomass. Mill wastewater treatment plant (WWTP) sludge will also be combusted. Natural gas will be utilized for startups and during some normal operating scenarios if there is an interruption in biomass fuel supply.

Installation of a new boiler allows the Macon Mill to shutdown the existing No. 1 Power Boiler, which combusts coal, fuel oil, and natural gas. Also, coal and fuel oil will no longer be used as fuel in the No. 2 Power Boiler with natural gas combustion capability being retained. Upon shutdown of the No. 1 Power Boiler and once the No. 2 Power Boiler is only firing natural gas, the existing scrubbers will no longer be in operation. This will occur following the necessary shake-down period for the No. 3 Biomass Boiler.

GPI will install biomass conveying equipment, sand handling equipment (for the proposed boiler's bed), a steam turbine generator, a cooling tower, and process tanks (lube oil and hydraulic oil for the proposed turbine) as part of the proposed project at the Macon Mill. Fly ash handling equipment will be installed to remove fly ash from the dry baghouse, bottom ash and boiler hopper ash handling equipment will be used to remove the bottom ash from the boiler, and a new aqueous ammonia day tank is proposed to accommodate the SNCR system. A sorbent handling and storage equipment will be installed to store the sorbent for the duct sorbent injection system, if necessary. A new steam turbine generator, to be rated at approximately 40 MW of electrical output, will be utilized to generate electricity for Mill use and to potentially be sold to the grid.

1.2 PERMITTING AND REGULATORY REQUIREMENTS

GPI is submitting this combined construction permit application and Title V significant modification application to the Georgia EPD pursuant to GRAQC 391-3-1-.03(1) and 391-3-1-.03(10)(e)5(iii), respectively, to request authorization to install and operate the proposed biomass boiler and associated emission units. GPI anticipates initiating construction of the project by the end of the third quarter of 2011.

Bibb County, home of the Macon Mill, is currently designated as a fine particulate matter ($PM_{2.5}$) nonattainment area. For all other criteria pollutants (i.e., carbon monoxide [CO], oxides of nitrogen [NO_X], sulfur dioxides [SO_2], particulate matter with an aerodynamic particle size of 10 microns or less [PM_{10}], ozone, and lead [Pb]), Bibb County has been designated as an attainment area or unclassifiable. As such, the proposed project potentially requires nonattainment new source review (NNSR) and/or Prevention of Significant Deterioration (PSD) permitting as discussed in Section 4.2. Therefore, net emission increases from the proposed project and modified emission units must be evaluated and compared to the major modification thresholds for regulated pollutants for NSR permitting applicability as shown in Table 1-1.

TABLE 1-1. PROPOSED PROJECT NET EMISSION INCREASES

Pollutant	Emissions (tpy)	NSR Major Modification Threshold (tpy)	Exceed NSR Threshold? (Yes/No)
Project Potential Emissions Increases			
VOC	30.5	40	No
Pb	0.1	0.6	No
H_2S	-	10	No
Fluoride[1]	-	3	No
Net Emissions Increase			
CO	421.7	100	Yes
NO_X	38.3	40	No
SO_2	-459.9	40	No
Total PM	-13.9	25	No
Total PM_{10}	14.5	15	No
Total $PM_{2.5}$	9.6	10	No
H_2SO_4	6.9	7	No
CO_2e[2]	68,649.5	75,000	No

1. Excluding hydrogen fluoride, which is regulated per Clean Air Act Section 112.

2. NSR permitting for greenhouse gases (i.e., CO_2e) is required if NSR permitting is triggered for any other pollutant and the permit application is submitted after January 2, 2011 but before July 1, 2011. CO_2e emissions exclude biogenic CO_2 emissions per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

As detailed in Section 3 and summarized in Table 1-1, net emission increases from the proposed project, when accounting for the 5-year contemporaneous emission period, will be below the PSD and NNSR major modification thresholds for all pollutants except CO.

With respect to GHG emissions, on May 13, 2010, the U.S. EPA issued the Tailoring Rule which establishes an approach for addressing GHG from stationary sources under the Clean Air Act (CAA) permitting programs (PSD and Title V).[1] Per the Tailoring Rule, as the proposed project requires NSR permitting for a criteria pollutant and the required PSD permit was not issued prior to January 2, 2011, PSD permitting for GHG for the proposed project must also be considered. On July 20, 2011, U.S. EPA published a rulemaking to defer GHG permitting requirements for three years for carbon dioxide (CO_2) emissions from biomass-fired and other biogenic sources.[2] The purpose of the deferral is to allow for additional time for U.S. EPA to seek further independent scientific analysis, complete a detailed examination of the science associated with biogenic CO_2 emissions, and consider the technical issues the agency must resolve to account for biogenic CO_2 emissions in ways that are both scientifically sound and manageable in practice. U.S. EPA intends to then issue a second rulemaking with a determination of how to account for CO_2 emissions from biogenic sources under GHG permitting requirements. As such, biogenic CO_2 emissions are excluded from the project CO_2e emissions.

For CO, a Best Available Control Technology (BACT) analysis and an air quality dispersion modeling analysis is required as part of the PSD permit application submittal.

As a Title V major source, GPI is required to submit a Title V significant modification application as part of the PSD permitting process in Georgia. GPI is submitting this construction and operating permit application in accordance with all federal and state requirements.

The proposed project will potentially be subject to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and several Georgia regulations. The proposed No. 3 Biomass Boiler will not be a major source of hazardous air pollutants (HAP). Accordingly, as the unit is part of a listed source category (i.e., Industrial Boilers) for which a NESHAP standard has not yet been promulgated, construction permitting for HAP (termed Section 112[g]) is not applicable to the proposed project, as discussed further in Section 4.4.5.[3]

1.3 BACT DETERMINATION

GPI performed a BACT analysis for the NSR-regulated pollutant that exceeds the major modification thresholds, CO, generally following the "top-down" approach suggested by U.S. EPA. The top-down process begins by ranking all potentially relevant control technologies in descending order of control effectiveness. The most stringent or "top" control option is BACT unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option does not meet the

[1] Rule was published in the Federal Register on June 3, 2010, and became effective August 2, 2010. Federal Register Vol. 75, No. 106, June 3, 2010, pages 31541 – 31608. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf

[2] Federal Register Vol. 76, No. 139, July 20, 2011

[3] While the NESHAP for Industrial Boilers was promulgated March 21, 2011, U.S. EPA stayed the effective date and is intended to repropose the regulation in October 2011, with finalization targeted for April 2012.

definition of BACT. Where the top option is not determined to be BACT, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is determined.

Based on the BACT review, GPI has determined that the technology and limits presented in Table 1-2 are BACT for the No. 3 Biomass Boiler during periods of normal operation. Separate BACT secondary limits will be established for the proposed No. 3 Biomass Boiler to address startup and/or shutdown events; refer to Section 6.10 for a discussion of the secondary BACT limits. The detailed analyses are presented in Section 6 of this report.

TABLE 1-2. PROPOSED PRIMARY BACT LIMITS SUMMARY

Pollutant	Limit	Units	Averaging Period	Control Technology
CO	0.15	Lb/MMBtu, CO	30-day	Good Design and Operating Practices

1.4 AIR QUALITY ANALYSIS

The air dispersion modeling and other air quality analyses required as part of this permit application will be provided under separate cover in Volume II. The modeling analyses will be conducted in accordance with an approved modeling protocol[4], U.S. EPA's *Guideline on Air Quality Models,* 40 CFR Part 51, Appendix W (Revised, November 9, 2005), the U.S. EPA's *AERMOD Implementation Guide*[5], and the Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (June 21, 1998).[6]

The modeling analyses will demonstrate that the project will not cause or contribute to an exceedance of any National Ambient Air Quality Standards (NAAQS) or Class II PSD Increment requirements by demonstrating that the project emission increases do not exceed the Modeling Significance Levels (MSL). An additional impacts analysis, consisting of an assessment of visibility degradation and potential impacts on soil, vegetation, and animals, will also be included in Volume II.

[4] Letter from Mr. Justin Fickas (Trinity Consultants) to Mr. Peter Courtney (Georgia EPD), January 14, 2011. Subsequent discussions and correspondence between Mr. Fickas and Mr. Courtney have established the approved modeling parameters.

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

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

1.5 APPLICATION ORGANIZATION

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

- ▲ Section 2 describes the current facility and the proposed project;
- ▲ Section 3 summarizes the emissions calculation methodologies;
- ▲ Section 4 details the federal regulatory applicability analysis for the proposed operations;
- ▲ Section 5 details the Georgia regulatory applicability analysis for the proposed operations;
- ▲ Section 6 contains the required BACT assessment;
- ▲ Appendix A contains facility diagrams;
- ▲ Appendix B includes documentation of emissions calculations;
- ▲ Appendix C contains BACT supporting information
- ▲ Appendix D contains State Implementation Plan (SIP) construction permit application forms; and
- ▲ Appendix E contains the Georgia EPD Title V operating permit application database and proposed permit conditions.

2. FACILITY AND PROCESS DESCRIPTION

The section provides an overview of the Macon Mill operations and a more detailed description of the proposed project. Note that the proposed project will not increase the Mill pulp or paper manufacturing capabilities.

2.1 FACILITY DESCRIPTION

The Macon Mill is an integrated pulp and paper mill that uses wood chips and recycled fiber to produce unbleached pulp, finished products such as coated and uncoated paperboard, and byproducts such as tall oil and turpentine. The overall process operations of the mill can be divided into several distinct areas such as pulping, chemical recovery, causticizing, paper machines, recycle plant, and utilities. Each process area is further described in this section of the report.

2.1.1 PULPING

The pulp and paper manufacturing process begins at the mill's chipyard where purchased wood chips are received, screened, and stored in piles. Chips not meeting the required size fraction are presently sent to the No. 2 Biomass Boiler for combustion while the properly sized chips remain stored in piles.

The chips are conveyed to a series of batch digesters for pulping where cooking chemicals and steam are added. Once pulping is complete, the content of the digesters is blown into blow tanks (residual steam from the blow tanks is recovered using a blow heat recovery system). The pulp is then further refined using solvos (inline deknotter and refiner), screens and chemi-washer systems. The resulting high-density pulp is stored in tanks and then fed to the paper machines for further processing into paper products.

The remaining major liquid streams generated in the pulp digestion process are turpentine and black liquor. Turpentine, generated during pulp digestion, is collected, condensed, dewatered and shipped out as a commercial byproduct. Black liquor is sent to the chemical recovery area for recovery of the cooking chemicals. The exhaust gases from the digesters are collected and sent to the non-condensable gas (NCG) collection system for further treatment and incineration in the recovery boiler or lime kilns.

2.1.2 CHEMICAL RECOVERY

Weak black liquor, which is a mixture of spent cooking chemicals and lignin suspended in water, is separated from the pulp in the pulp washing area and routed to the chemical recovery area. Here, the cooking chemicals are recovered for use in the pulp digestion process while the lignin is combusted for steam generation. The major process units in this area consist of evaporators, a recovery boiler and a smelt dissolving tank.

The weak black liquor streams from the pulping process, which generally range from 10-15% solids concentration, are fed to evaporators and concentrated until an acceptable solids concentration is achieved. The resulting strong black liquor is then sprayed in the oxidizing zone of the No. 3 Recovery Boiler where organic components are combusted and generate heat for steam production. Below the oxidizing zone, spent cooking chemicals are reduced and form a molten mass known as smelt. The smelt flows from the bottom of the recovery boiler and dissolved with weak wash or water in the smelt dissolving tank to produce green liquor. The green liquor is processed in the causticizing area to produce white liquor that will be used in the chip digestion process.

The gases from the evaporators are collected and sent to the NCG collection system for further treatment and incineration in the recovery boiler or lime kilns. The recovery boiler serves as an incineration point of the various NCG streams collected.

The exhaust gases from the recovery boiler are treated in an ESP before being emitted to the atmosphere. The precipitator ash separated from this gas stream is mixed with the black liquor stream and re-processed in the chemical recovery system. The exhaust gases from the smelt dissolving tank are treated in a scrubber before being emitted to the atmosphere.

2.1.3 CAUSTICIZING

The green liquor produced in the smelt dissolving tank is clarified and filtered to remove dregs (which are land-filled offsite). The filtered green liquor is fed to a slaker where lime (calcium oxide) is added to generate white liquor. The chemical reaction to convert green liquor to white liquor is completed in the causticizers. The white liquor is then clarified and the settled solids (also called lime mud) are separated from the liquid stream. The white liquor is then fed to the batch digesters for pulping of wood chips.

Lime mud is washed and stored until it is processed in the lime kilns, which convert it from hydrated lime back to calcium oxide. The hot lime from the lime kilns is screened and added to green liquor in the slakers. The wash water from lime mud washing is returned to the smelt dissolving tank as weak wash. The lime kilns also serve as a point of combustion for NCG incineration, and their exhaust gases are treated in scrubbers.

2.1.4 PAPER MACHINES

The papermaking operations at the Macon Mill consist of paper machines, coatings and additives systems, and storage silos. The first step is stock preparation, which involves pulp blending, diluting, refining, chemical addition and metering. Different combinations of pulp, chemicals, and additives are used to produce various grades of paper products. The majority of pulp consumed in the paper machines is generated on-site in either the pulp mill or recycle plant.

Pulp is fed to the paper machines where it is dewatered to form a paper sheet. In-line coaters are used to produce coated paperboard. The coating that is applied to the paper sheet is prepared in a separate building. The coatings are applied to the substrate using rod and air knife coaters. The coating is dried by natural gas dryers.

2.1.5 RECYCLE PLANT

The Macon Mill includes a recycling plant for utilizing used secondary fiber products in papermaking. Typically, secondary fiber bales are received in the warehouse by truck and rail car. These bales are conveyed to the hydro-pulpers where steam and Mill water are added to convert the recycled secondary fiber into useful fibers. The resulting product is passed through several stages of cleaning, screening, and thickening after which it is supplied to the paper machines.

2.1.6 UTILITIES

The steam generating units at the Macon Mill presently consist of two power boilers that primarily combust coal, recycled oil, and natural gas (Nos. 1 and 2 Power Boilers) and a biomass boiler (No. 2 Biomass Boiler) capable of firing biomass, coal, natural gas, recycled oil, and pulp mill residuals (WWTP sludge). The steam generated in these boilers is sent to a common header along with the steam generated in the No. 3 Recovery Boiler for distribution in the Mill. The exhaust gases from the power boilers and biomass boiler are treated in individual scrubber systems prior to discharging to the atmosphere.

The proposed project impacts the utilities section of the Mill and is described in Section 2.2.

2.1.7 MISCELLANEOUS UNITS

The Macon Mill also includes a wastewater pretreatment system, oil storage tanks, coal storage silos, and paper product storage areas. The wastewater pretreatment system consists of neutralization followed by primary clarification and biological treatment. The pretreated wastewater is discharged to the Macon Water Authority’s Rocky Creek wastewater treatment system. Additional auxiliary and miscellaneous equipment will be installed as part of the proposed project, described further in Section 2.2.

2.2 PROJECT DESCRIPTION

GPI is proposing to install a new BFB boiler, steam turbine generator, and associated emission units at the Macon Mill. The proposed No. 3 Biomass Boiler, to be rated at approximately 620 MMBtu/hr, will be designed to combust a variety of fuels and will be equipped with flue gas recirculation, a baghouse, and SNCR. GPI is proposing installation of SNCR, to be relied upon as-needed, to ensure that annual NO_X emissions for the proposed No. 3 Biomass Boiler remain below levels necessary to ensure NSR permitting is not required for NO_X or $PM_{2.5}$ for the project. In addition, the proposed boiler could potentially be equipped with a sorbent duct injection system to provide additional control of hydrogen chloride (HCl). GPI is also evaluating the need for powder activated carbon injection. Presently, GPI is proposing to install a sorbent duct injection system and/or a powder activated carbon injection system only if necessary. GPI intends to exhaust the No. 3 Biomass Boiler through the existing Nos. 1 and 2 Power Boilers stack.

The primary fuel will be biomass, with the ability to combust mill WWTP sludge. To ensure the proposed No. 3 Biomass Boiler is not considered a Commercial and Industrial Solid Waste

Incineration (CISWI) unit, GPI will combust clean cellulosic biomass materials defined by U.S. EPA as follows:[7]

> *Clean cellulosic biomass means those residuals that are akin to traditional cellulosic biomass such as forest-derived biomass (e.g., green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials), corn stover and other biomass crops used specifically for energy production (e.g., energy cane, other fast growing grasses), bagasse and other crop residues (e.g., peanut shells), wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, clean biomass from land clearing operations, and clean construction and demolition wood. These fuels are not secondary materials or solid wastes unless discarded. Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials.*

Natural gas will be utilized for startups and during some normal operating scenarios if there is an interruption in biomass fuel supply. The boiler will have three natural gas startup burners with a maximum heat input capacity of 45 MMBtu/hr (135 MMBtu/hr total) and two natural gas load burners with a maximum heat input capacity of 122 MMBtu/hr (244 MMBtu/hr total). GPI will restrict operation of the burners such that the maximum heat input capacity of natural gas that can be fired at a given time does not exceed 249 MMBtu/hr. The "worst-case" natural gas firing scenario is a cold-start up of the No. 3 Biomass Boiler utilizing solely natural gas in the three startup burners plus one load burner and then moving to load burning of natural gas without any biomass firing.[8] GPI anticipates one complete shutdown and startup per year, with possible unplanned incidents stemming from malfunction events. Annual natural gas usage will be limited to 10 percent of the maximum heat input capacity of the unit, although actual usage is expected to be considerably smaller as it is more economical to combust biomass than natural gas.

GPI will be retiring the existing No. 1 Power Boiler and limiting the No. 2 Power Boiler to just natural gas (i.e., removing coal and fuel oil combustion capabilities).[9] In addition, once the No. 2 Power Boiler is only firing natural gas, the existing scrubber will no longer be utilized.

The new steam turbine generator, to be rated at 40 MW of electrical output, will be fed exclusively by the new No. 3 Biomass Boiler. It will be utilized to primarily generate electricity for Mill use; however, GPI may sell some portion of the electricity generated to the utility grid. The casing of the electric generator for the steam turbine is cooled with air. Therefore, since a flammable gas such as

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[7] *Identification of Non-Hazardous Secondary Materials that are Solid Waste* (solid waste definition), as published in the Federal Register on March 21, 2011 (Volume 76, No. 54, pages 15456 – 15551).

[8] Although the maximum heat input capacity of the worst-case scenario is 257 MMBtu/hr, GPI will limit the natural gas input to 249 MMBtu/hr.

[9] During construction, it will be necessary to disconnect the power boilers from their existing stack in order to tie in the proposed No. 3 Biomass Boiler. At this time, GPI will install stub stacks on each power boiler, and the units will only combust natural gas and will no longer route through the scrubbers. Note the No. 1 Power Boiler must remain in operation until shakedown of the No. 3 Biomass Boiler is complete to support facility operations. Upon completion of the shakedown period, the No. 1 Power Boiler will be permanently shutdown.

hydrogen is not used as coolant air, there is no need to periodically purge the generator casing during steam turbine shutdowns for maintenance with an inert gas such as CO_2. In some cases, circuit breakers such as the ones associated with the electrical distribution systems for this project may use sulfur hexafluoride (SF_6), a GHG, as a gaseous dielectric and an arc quenching medium. Fugitive leaks of SF_6 can occur with these types of breakers. However, with regard to this project, there will not be any SF_6 compounds in any of the electrical equipment.

In addition to the new boiler and steam turbine generator, new ancillary equipment will also be required to support the proposed project. The existing biomass fuel storage and handling system will be supplemented with new conveyors to transport biomass to the No. 3 Biomass Boiler. Additionally, the existing bark hog tower and hammer hog and truck dump will experience throughput increases to accommodate the proposed boiler. The proposed boiler design includes a bed comprised of sand, and thus a new sand silo with a fabric filtration system and associated conveyors will be installed. Because the new biomass boiler will use a dry control device system to reduce PM emissions, a new fly ash handling system and ash storage silo with a fabric filtration system will be constructed. In addition, bottom ash and boiler hopper ash handling equipment will be installed to remove and store the bottom ash generated by the boiler. The proposed bottom ash and boiler hopper ash handling equipment will include a container located in the boiler house as well as transfer points from the boiler discharge. If needed, a sorbent handling system and storage silo equipped with a fabric filtration system may be installed to store the alkaline sorbent (i.e., Trona or similar sorbent material) that could be injected into the boiler flue gas stream immediately after the boiler as part of a duct sorbent injection system for HCl control. Also, a small aqueous ammonia day tank will be added to the Macon Mill to store ammonia for usage in the SNCR. In order to support the new steam turbine generator, a new cooling tower and generator lube oil and hydraulic oil process tanks will also be installed.

As part of the proposed project, the facility will experience an increase in truck traffic on paved plant roads. The following materials will be delivered to the plant by truck on paved roadways:

- Biomass (increased delivery from existing)
- Sand
- Aqueous ammonia (increased delivery from existing)
- Alkaline sorbent (if sorbent injection system is installed)
- Miscellaneous materials and chemicals (e.g., lube oil and hydraulic oil for the steam turbine generator)

Additionally, ash generated by the boiler will potentially be removed from the plant by truck.

Note that there will be a reduction in actual throughput to the existing coal storage system (emission unit B004) because of the reduced coal demand due to the shutdown of the No. 1 Power Boiler and removal of coal combustion from the No. 2 Power Boiler.

3. EMISSIONS CALCULATIONS METHODOLOGY

This section presents the emissions analysis for the proposed biomass boiler project, with a particular focus on NSR calculations. The proposed new equipment and existing equipment changes result in an increase in emissions of some criteria pollutants, HAP, and GHG. Note that there will be no production increases at the Macon Mill and thus there will be no associated emission increases from the pulp and paper mill manufacturing sources. Therefore, manufacturing equipment is excluded from the emissions analysis.

3.1 NSR PERMITTING EVALUATION METHODOLOGY

The following sections discuss the methodology used in the project emissions increase evaluation calculations conducted to assess NSR applicability. The NSR permitting program generally requires that a source obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. Georgia has incorporated by reference 40 CFR §52.21 with several amended definitions, detailed herein.[10] NSR permitting requirements are discussed in more detail in Section 4.2.

3.1.1 DEFINING EXISTING VERSUS NEW EMISSION UNITS

Different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the proposed project is considered a new or existing emission unit.

40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units:

> (i) *A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> (ii) *An existing emissions unit is any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

Based on these definitions, the sources that will be impacted by the proposed project at the Macon Mill are classified as follows:

[10] GRAQC 391-3-1-.02(7)

- Existing Units: No. 1 Power Boiler and No. 2 Power Boiler, paved roads truck traffic, biomass handling and storage equipment
- New Units: No. 3 Biomass Boiler, ash storage and handling equipment, sand silo and handling equipment, dry sorbent (Trona) silo and handling equipment (if needed), cooling tower, process tanks (aqueous ammonia, lube oil, and hydraulic oil)

3.1.2 ANNUAL EMISSION INCREASE CALCULATION METHODOLOGY

As the Mill is classified as a major source for NSR, if the proposed project were classified as a *major modification*, then the full NSR permitting requirements would apply. GPI evaluated project increases to determine if the proposed project is a major modification using the applicable NSR calculation methodologies. As the proposed project involves new and existing emission units, the hybrid methodology was relied upon for estimating project emission increases.

For projects involving multiple types of emission units, NSR applicability using the hybrid test is defined at GRAQC 391-3-1-.02(7)(a)(3)(ii)(I):

> (f) *Hybrid test for projects that involve multiple types of emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(c) through (d)… for each type of emissions unit equals or exceeds the significant amount for that pollutant….*

Paragraph (a)(2)(iv)(c) provides the emission increase calculation method for existing units:

> (c) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant ….*

Paragraph (a)(2)(iv)(d) provides the emission increase calculation method for new emission units:

> (d) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s). A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit… from each new emissions unit… and the baseline actual emissions… equals or exceeds the significant rate for that pollutant….*

Major modification is defined by 40 CFR 52.21(b)(2)(i):

> *"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase … of a regulated NSR pollutant … and a significant net emissions increase of that pollutant …*

As the project is classified as a physical change, the project needs to be analyzed to determine if a significant net emissions increase will occur.

Net emissions increase (NEI) is defined by 40 CFR 52.21(b)(3)(i):

> *"Net Emissions Increase" means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:*
>
> > *(a) The increase in emissions … as calculated pursuant to paragraph (a)(2)(iv) [for existing units, calculated by actual-to-projected actual or actual-to-potential; for new units, calculated by actual-to-potential] of this section; and*
> >
> > *(b) Any other increases or decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…*

The first step (A) is commonly referred to as the "project emission increases" as it accounts only for emissions related to the proposed project itself. This first step in the analysis does not include the proposed shutdown of equipment associated with the project. If the emission increases estimated per step (A) exceed the major modification thresholds, then the applicant may move to step (B), commonly referred to as the 5-year netting analysis. The netting analysis includes all projects for which emission increases or decreases (i.e., equipment shutdown) occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting is required.

While the prior quotations only reference three components of the NEI calculation, there are actually four calculated components, with the additional component being a subset of the definition for *projected actual*. The four components are listed below and are discussed individually, as appropriate.

1. Baseline actual emissions (A)
2. Projected actual emissions (B)
3. "Could have accommodated" emissions exclusion (C) (commonly called the demand growth exclusion)
4. Potential emissions (D)

For this project, GPI has not relied upon projected actual emissions or the "could have accommodated" emissions exclusion. These methods could have been employed to estimate emissions for the No. 2 Power Boiler, but the more conservative baseline actual emissions-to-potential emissions methodology has been relied upon.

3.1.3 BASELINE ACTUAL EMISSIONS (A)

Baseline actual emissions are the most straightforward of the components, and are defined in GRAQC 391-3-1-.02(7)(a)(2)(i)(II).

> *For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Division for a permit required under this paragraph...*

Per GRAQC 391-3-1-.02(7)(a)(2)(i)(II)I.B.IV, when a project involves multiple emission units, only one consecutive 24-month period may be used to determine the baseline actual emissions for all of the emission units to be modified. However, a different consecutive 24-month period can be used for each pollutant.

3.1.4 POTENTIAL EMISSIONS (D)

Potential emissions are defined by GRAQC 391-3-1-.02(7)(a)(2)(v) where the potential to emit:

> *…means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollutant control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable or enforceable as a practical matter...*

Any modification to the facility that has the potential to increase emissions of any air pollutant(s) regulated under the PSD or NNSR program must be evaluated to determine if the changes are subject to PSD or NNSR. Per GRAQC 391-3-1-.01(pp), a "modification" is defined as:

> *…any change in or alteration of fuels, processes, operation or equipment, (including any chemical changes in processes or fuels) which affects the amount or character of any air pollutant emitted or which results in the emission of any air pollutant not previously emitted.*

The proposed changes to the Macon Mill qualify as a "modification" under this definition. Therefore, the proposed process changes are identified as a potential modification requiring evaluation under the NSR permitting program.

3.2 PROPOSED PROJECT EMISSIONS INCREASES

The following sections summarize the methods to estimate the emissions increases from the proposed project for comparison to the NSR permitting major modification thresholds.

3.2.1 NO. 3 BIOMASS BOILER (NEW UNIT)

The new No. 3 Biomass Boiler will combust biomass, natural gas, and sludge and emit criteria pollutants, HAP, and GHG. The potential emissions from the proposed boiler for each pollutant were assumed to be the maximum emissions of the potential fuel firing scenarios. Potential emissions from the proposed biomass boiler were estimated based on a combination of applicable regulatory emission standards, vendor data, NSR avoidance emission factors, and emission factors established by the U.S. EPA. Refer to Section 3.4 for a summary of the potential HAP emissions calculations.

Potential CO emissions were calculated based on the proposed primary CO BACT limit of 0.15 lb/MMBtu (discussed in Section 6.5.6) and the boiler's maximum heat input capacity. Potential annual CO emissions were estimated assuming 8,760 hours of operation per year.

Potential annual NO_X emissions were established to ensure NSR avoidance for NO_X and $PM_{2.5}$ for the proposed project. To ensure compliance with the proposed annual NO_X limitation, GPI is proposing installation of an SNCR to be operated as necessary (i.e., not necessarily continuously). Similarly, potential annual sulfuric acid mist (H_2SO_4) emissions were established to ensure NSR avoidance for H_2SO_4 for the proposed project.

The filterable PM emission factor is the applicable NSPS Subpart Db requirement of 0.030 lb/MMBtu. The emission factor for condensable particulate matter (CPM) was taken from U.S. EPA's AP-42, Fifth Edition, Volume I, Chapter I, Section 1.6, *Wood Residue Combustion in Boilers*.[11] Total PM emissions were estimated as the sum of the filterable PM and CPM emissions. Emission factors for total PM_{10} and total $PM_{2.5}$ were established to avoid NSR permitting for PM_{10} and $PM_{2.5}$ for the proposed project. GPI will achieve compliance with these limitations through the operation of a baghouse.

SO_2 emissions are based on an emission factor of 0.32 lb/MMBtu, which presumes that the boiler's emissions are less than the NSPS Subpart Db SO_2 emissions threshold that requires an SO_2 limitation. This SO_2 emission factor is supported by information provided by the boiler vendor (Andritz) based on the potential fuels' sulfur contents.

[11] Versions dated September 2003. Note that the CPM emission factor for natural gas combustion per U.S. EPA's AP-42 Section 1.4, *Natural Gas,* dated July 1998, is lower than the biomass combustion emission factor; thus, GPI conservatively estimated potential CPM emissions based on the maximum value.

VOC emissions are based on the boiler vendor's guaranteed emission rates. The emission factor for lead (Pb) was taken from U.S. EPA's AP-42, Fifth Edition, Volume I, Chapter I, Section 1.6, *Wood Residue Combustion in Boilers*.[12]

On July 20, 2011, U.S. EPA published the *Deferral for CO_2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs* (Biomass Deferral) to postpone the inclusion of carbon dioxide (CO_2) emissions from bioenergy and other biogenic stationary sources in PSD and Title V permitting assessments for a period of three years.[13] Accordingly, GPI has estimated the boiler's maximum potential GHG emissions excluding CO_2 emissions from biomass combustion. Emission of methane (CH_4) and nitrous oxide (N_2O) from biomass combustion were based on data provided by the boiler vendor (Andritz), and emissions of CO_2, CH_4, and N_2O from natural gas combustion were estimated using emission factors per 40 CFR 98 Subpart C, Tables C-1 and C-2. Maximum potential emissions for each GHG pollutant were selected as the higher emissions between biomass and natural gas combustion. Carbon dioxide equivalent (CO_2e) emissions were calculated based on the global warming potentials (GWP) provided in 40 CFR 98 Subpart A, Table A-1.

Table 3-1 summarizes the No. 3 Biomass Boiler's potential emissions.

TABLE 3-1. NO. 3 BIOMASS BOILER POTENTIAL EMISSIONS

Pollutant	Worst-Case Potential Emissions (lb/hr)	(tpy)
CO	93.00	407.34
NO_X	92.38	404.62
SO_2	198.40	868.99
VOC	6.20	27.16
PM filterable	18.60	81.47
CPM	10.54	46.17
Total PM	29.14	127.63
Total PM_{10}	30.38	133.06
Total $PM_{2.5}$	24.80	108.62
Pb	0.03	0.13
H_2SO_4	3.01	13.17
H_2S	-	-
Fluoride (non-HF)	-	-
$CO_2e_{\text{non-biogenic}}$	34,936.45	153,021.65

[12] Versions dated September 2003. Note that the CPM emission factor for natural gas combustion per U.S. EPA's AP-42 Section 1.4, *Natural Gas,* dated July 1998, is lower than the biomass combustion emission factor; thus, GPI conservatively estimated potential CPM emissions based on the maximum value.

[13] Federal Register Vol. 76, No. 139, July 20, 2011.

Note that potential emissions from the No. 3 Biomass Boiler assume the unit operates continuously at maximum capacity because the number of startups and shutdowns per year cannot be easily defined/anticipated for an industrial unit (refer to Section 2.2).

3.2.2 NO. 2 POWER BOILER (EXISTING UNIT)

The No. 2 Power Boiler is currently capable of firing coal, fuel oil, and natural gas. As a result of the proposed project, GPI will limit fuel combustion to natural gas and no longer combust coal or oil in this boiler. GPI considers the No. 2 Power Boiler to be an associated emissions unit that is realizing a change in emissions from the removal of coal and oil combustion as a result of the proposed installation of the No. 3 Biomass Boiler. GPI has conservatively represented this associated emissions change relying on the actual-to-potential emissions increase evaluation to determine the project emission increases for the No. 2 Power Boiler.

Past actual emissions from the No. 2 Power Boiler can be represented as the maximum two-year annual emissions averaged over the previous ten year period from the date of application submittal (i.e., looking back to 2001) as discussed in Section 3.1.3. Past actual annual emissions of criteria pollutants and HAP from the boiler were estimated based on actual fuel usage and emission factors for coal, fuel oil, and natural gas from U.S. EPA's AP-42, Fifth Edition, Volume I, Chapter I, Section 1.1, *Bituminous and Subbituminous Coal Combustion,* Section 1.3, *Fuel Oil Combustion*, and Section 1.4, *Natural Gas Combustion,* respectively.[14] Past actual emissions of GHG pollutants, specifically CO_2, CH_4, and N_2O, were estimated using the fuel-specific emission factors from 40 CFR 98 Subpart C, Tables C-1 and C-2, and CO_2e emissions were calculated based on the GWP provided in 40 CFR 98 Subpart A, Table A-1.

Potential emissions from the combustion of natural gas were estimated based on the AP-42 Section 1.4 emission factors and the boiler's maximum heat input capacity. Note that once the No. 2 Power Boiler is only firing natural gas, the existing scrubber will no longer be utilized.

Table 3-2 summarizes the past actual emissions and future potential emissions from the No. 2 Power Boiler.

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[14] Versions dated September 1998, May 2010, and July 1998, respectively.

TABLE 3-2. NO. 2 POWER BOILER EMISSIONS INCREASES

Pollutant	Potential Emissions (tpy)	Past Actual Emissions (tpy)	Net Emissions Increase[1] (tpy)
CO	20.33	8.85	11.47
NO_X	143.98	262.49	-118.51
SO_2	0.51	674.97	-674.46
VOC	4.66	1.30	3.36
Total PM	6.44	97.32	-90.88
Total PM_{10}	6.44	77.67	-71.23
Total $PM_{2.5}$	6.44	64.56	-58.13
Pb	4.23E-04	7.33E-03	-6.90E-03
H_2SO_4	-	3.24	-3.24
Fluoride (non-HF)	-	1.65E-04	-1.65E-04
CO_2e	101,470.20	92,572.06	8,898.14

1. The net emissions increases from the No. 2 Power Boiler is equal to the future potential emissions minus the past actual emissions.

3.2.3 ANCILLARY EQUIPMENT EMISSIONS INCREASES

New ancillary equipment sources will be installed to support the proposed No. 3 Biomass Boiler. In addition, existing emission sources at the Mill will realize associated emission increases to accommodate increased road traffic and increased raw material storage and handling. Note that GPI has conservatively not included associated emissions decreases due to the reduced coal storage system throughput. Additionally, none of the pulp and paper manufacturing equipment is impacted by the proposed project, and there will not be an increase in pulp or paper production as a result of the proposed project. Hence, no associated emission increases from manufacturing equipment is included in the net emission increase analysis.

3.2.3.1 BIOMASS HANDLING AND STORAGE (EXISTING)

The proposed biomass boiler will necessitate additional conveyors and transfer points in the existing biomass handling and storage system. PM, PM_{10}, and $PM_{2.5}$ emissions from the additional drop and transfer points to accommodate the new biomass boiler were calculated per AP-42 Section 13.2.4, *Aggregate Handling and Storage Piles*. In addition, the bark hog tower and hammer hog used to resize oversized bark chips will experience an increase in throughput to accommodate the No. 3 Biomass Boiler.[15] PM emissions increases from the

[15] The existing bark hog is part of the North Biomass Feed System and has potential PM emissions of 6.36 tpy. The unit will experience a potential PM emissions increase of 4.38 tpy from the increased throughput to accommodate the No. 3 Biomass Boiler. Accordingly, the bark hog is considered a Title V significant emission unit due to total potential emissions of 10.74 tpy. GPI is adding this unit as a significant emission unit in the proposed permit conditions and Title V application database included in Appendix E.

bark hog were estimated based on the emission factor for log debarking per AP-42 Section 10.3-1, *Wood Products Industry*, Table 10.3-1.[16] PM_{10} emissions were assumed equal to 60% of PM based on the Bay Area Air Quality Management District *Permit Handbook*, and $PM_{2.5}$ emissions were conservatively assumed to equal PM_{10}.[17] Note only filterable PM, filterable PM_{10}, and filterable $PM_{2.5}$ are emitted from the biomass handling and storage sources.

3.2.3.2 SAND HANDLING AND STORAGE (NEW UNIT)

The proposed sand handling and storage system will include a silo as well as conveyors to transfer sand between the proposed biomass boiler, silo, and truck load out. GPI plans to enclose or control all sand handling conveyors, and thus, particulate emissions are not expected from the sand handling equipment. The proposed sand collection silo will be equipped with a dust collector to minimize particulate emissions. The dust collector will have a maximum exit grain loading of 0.01 grains per dry standard cubic feet (gr/dscf). Potential emissions were evaluated by using the exit grain loading and the exhaust flow rate of 8.3 cubic feet per minute. GPI has conservatively assumed that PM_{10} and $PM_{2.5}$ emissions are equivalent to PM emissions from the silo. It was conservatively assumed that the sand handling and collection system will operate continuously over 8,760 hours per year. Note only filterable PM, filterable PM_{10}, and filterable $PM_{2.5}$ will be emitted from the sand handling and storage sources.

3.2.3.3 ASH HANDLING AND STORAGE (NEW UNIT)

The proposed fly ash handling system will include an ash silo as well as conveyors to transfer fly ash between the proposed biomass boiler, ash silo, and truck load out. Note that the fly ash silo discharge will be equipped with an unloading conditioner to wet the material, and the conveyors will all be enclosed; thus, particulate emissions are not expected from the fly ash handling equipment. The proposed ash collection silo will be equipped with a dust collector to limit particulate emissions. The dust collector will have a maximum exit grain loading of 0.01 gr/dscf. Potential emissions were evaluated by using the exit grain loading and the exhaust flow rate of 1,000 cubic feet per minute. GPI has conservatively assumed that PM_{10} and $PM_{2.5}$ emissions are equivalent to PM emissions from the silo. It was conservatively assumed that the ash handling and collection system will operate continuously over 8,760 hours per year. Note only filterable PM, filterable PM_{10}, and filterable $PM_{2.5}$ will be emitted from the ash handling and storage sources.

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[16] Version dated September 1985. www.epa.gov/ttn/chief/old/ap42/4th_edition/ap42_4thed_withsuppsa_f.pdf. Also recommended by Bay Area Air Quality Management District (BAAQMD) Permit Handbook for biomass tub grinding operations. www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_11_13.pdf.

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

The proposed bottom ash and boiler hopper ash handling equipment will include a container located in the boiler house as well as transfer points from the boiler discharge. However, the bottom ash and boiler hopper ash will be significantly more dense than fly ash, consist of primarily sand and small rocks, and consequently result in unquantifiable fugitive emissions; therefore, GPI has assumed that the PM emissions are negligible from the bottom ash system.

3.2.3.4 SORBENT HANDLING AND STORAGE (NEW UNIT)

The proposed dry sorbent inject system (if necessary) will require a sorbent handling and storage system. The proposed system would include a silo as well as conveyors to transfer sorbent between the proposed biomass boiler sorbent injection system, silo, and truck load out. GPI plans to enclose or control all sorbent handling conveyors, and thus, particulate emissions are not expected from the handling equipment. The proposed sorbent silo would be equipped with a dust collector to minimize particulate emissions. The dust collector will have a maximum exit grain loading of 0.01 gr/dscf. Potential emissions were evaluated by using the exit grain loading and the exhaust flow rate of 16.7 cubic feet per minute. GPI has conservatively assumed that PM_{10} and $PM_{2.5}$ emissions are equivalent to PM emissions from the silo. It was conservatively assumed that the sorbent handling and collection system would operate continuously over 8,760 hours per year. GPI has conservatively included emission increases from these possible units in the net emission increase analysis even though GPI is not yet certain such emission units will be required. Note only filterable PM, filterable PM_{10}, and filterable $PM_{2.5}$ will be emitted from the sorbent handling and storage sources.

3.2.3.5 SORBENT USAGE (NEW UNIT)

The usage of the proposed dry sorbent injection system (if necessary) will result in potential CO_2 emissions due to the chemical reaction between the sorbent used and HCl, the pollutant for which sorbent may be utilized to control.[18] GPI estimated the potential emissions according to the mass balance equation provided in 40 CFR 98.33(d)(1), assuming Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) will be used as the sorbent. HCl is removed from the exhaust stream when reacted with the dry sorbent and CO_2 is released according to the following equation:[19]

$$\mathrm{Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O + 3HCl \rightarrow 3NaCl + 2CO_2\ + 4\ H_2O}$$

Estimated emissions of CO_2 are predicated based on an assumed annual quantity of Trona injected. Detailed calculations are presented in Appendix B.

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[18] Sorbent injection would also provide SO_2 reduction benefits in addition to acid gas removal.

[19] NaCl and H_2O are not considered air pollutants.

3.2.3.6 COOLING TOWER (NEW UNIT)

A new 38,000 gallon per minute cooling tower will be added to the Macon Mill to support the new steam turbine generator. Cooling towers produce a small amount of PM emissions when water droplets evaporate, leaving the dissolved solids in the water as PM. Emissions from the cooling towers were based on less than 0.005% drift loss, a design circulation rate of 38,000 gallons per minute (gpm), and an estimated maximum total dissolved solids (TDS) content of 2,500 mg/L.[20] Note PM, PM_{10}, and $PM_{2.5}$ emitted from the cooling tower will include filterable and condensable particulate.

3.2.3.7 PROCESS TANKS (NEW UNITS)

The proposed turbine lube oil and turbine hydraulic oil tanks will be process tanks, meaning that the oils will not leave the system. Thus, these proposed tanks will not experience turnover like a typical storage tank. Therefore, potential emissions were not calculated.

While a new ammonia day tank will be installed to support the SNCR system, ammonia is not an organic compound, hence there are no criteria pollutant emission increases resulting from either the new day tank or the increased throughput of ammonia through the existing ammonia storage tank.

3.2.3.8 ROADS (EXISTING)

Fugitive PM emissions from the increased truck traffic on the facility roadways were estimated based on the vehicle miles travelled (VMT) by trucks that will transport additional materials to and from the facility. Vehicle miles traveled on site were estimated based on the distance of the anticipated truck route for each material and the number of trips necessary to support continuous operation of the No. 3 Biomass Boiler. Emission calculations for fugitive paved road dust emissions were developed based on AP-42, Section 13.2.1, *Paved Roads*; detailed calculations are included in Appendix B.[21] Note only filterable PM, filterable PM_{10}, and filterable $PM_{2.5}$ are emitted from the truck traffic on the facility roadways.

3.2.4 PROJECT EMISSIONS INCREASES

The following table summarizes the total emissions increase from the proposed project and compares to the applicable NSR major modification thresholds.

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

[21] U.S. EPA AP-42, Section 13.2.1, *Paved Roads*, January 2011.

TABLE 3-3. PROPOSED PROJECT EMISSION INCREASES

Pollutant	No. 3 Biomass Boiler PTE (tpy)	Ancillary Equipment PTE Increase (tpy)	No. 2 Power Boiler PTE Increase[1] (tpy)	Total Project Emissions (tpy)	NSR Major Modification Threshold (tpy)	Project PTE Exceed NSR Threshold? (Yes/No)
CO	407.3	-	11.5	418.8	100	**Yes**
NO_X	404.6	-	-118.5	286.1	40	**Yes**
SO_2	869.0	-	-674.5	194.5	40	**Yes**
VOC	27.2	-	3.4	30.5	40	No
Total PM	127.6	11.0	-90.9	47.8	25	**Yes**
Total PM_{10}	133.1	6.9	-71.2	68.7	15	**Yes**
Total $PM_{2.5}$	108.6	5.1	-58.1	55.6	10	**Yes**
Pb	0.1	-	-	0.1	0.6	No
H_2SO_4	13.2	-	-3.2	9.9	7	**Yes**
H_2S	-	-	-	-	10	No
Fluoride[2]	-	-	-	-	3	No
$CO_2e_{\text{non-biogenic}}$[3]	153,021.6	142.1	8,898.1	162,061.9	75,000	**Yes**

1. Represents baseline actual to new potential analysis.
2. Excluding hydrogen fluoride, which is regulated per Clean Air Act Section 112.
3. CO_2e emissions exclude biogenic CO_2 emissions; CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

As shown in Table 3-3, emissions increases from the proposed project alone (Step (A) of the NEI analysis) exceed the major modification thresholds for CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e, and thus, GPI evaluated the change in emissions from projects completed during the previous five-year contemporaneous period (Step (B) of the NEI analysis) as discussed in the following sections.

3.3 CONTEMPORANEOUS NETTING ANALYSIS

GPI reviewed all projects completed at the Macon Mill within the past five years to determine the total emissions increases of CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e for comparison to the applicable NSR thresholds for Step (B). As the proposed project will begin construction in 2011, the five calendar year period to review includes 2007 through 2011. Should the total emissions increases of any pollutant within the contemporaneous period exceed the respective major modification threshold, then the proposed project is subject to NSR permitting for that pollutant.

Table 3-4 details the projects at the Macon Mill with emissions changes since 2007.[22] In addition, Table 3-4 summarizes the total net emissions change over the contemporaneous period for CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e, which includes the proposed project.

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[22] Please refer to Appendix B for detailed calculations of the emissions decrease from the shutdown of the No. 1 Power Boiler planned after the installation of the No. 3 Biomass Boiler.

TABLE 3-4. 5-YEAR CONTEMPORANEOUS NETTING ANALYSIS

Date	Project	Emissions (tpy) CO	NO_X	SO_2	Total PM	Total PM_{10}	Total $PM_{2.5}$	H_2SO_4	*$CO_2e_{\text{non-biogenic}}$ [1]
2007	Stacker/Reclaimer System Addition	-	-	-	-	-	-	-	-
2010	No. 1 Paper Machine Steam Upgrades	12.1	14.2	14.37	7.45	4.4	4.1	0.2	**
2011	North Biomass Feed System Restoration	-	-	-	6.4	3.8	3.8	-	-
2011/2012	No. 1 Power Boiler Shutdown	-9.2	-262.1	-668.8	-75.5	-62.5	-53.9	-3.2	-93,412.4
2011/2012	Proposed Project (No. 3 Biomass Boiler)	418.8	286.1	194.5	47.8	68.7	55.6	9.9	162,061.9
Total Contemporaneous Period Emissions (tpy)		421.7	38.3	-459.9	-13.9	14.5	9.6	6.9	68,649.5
PSD/NNSR Major Modification Threshold (tpy)		100	40	40	25	15	10	7	75,000
PSD/NNSR Permitting Required?		**Yes**	No	No	No	No	No	No	No

* NSR permitting for greenhouse gases (i.e., CO_2e) is required if the total contemporaneous period emissions exceed the CO_2e major modification threshold AND if NSR permitting is triggered for any other pollutant and the permit application is submitted after January 2, 2011 but before July 1, 2011.

** Some CO_2e emissions may have occurred from the No. 1 Paper Machine steam upgrades project that were not required to be quantified.

1. CO_2e emissions exclude biogenic CO_2 emissions; CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

As shown in Table 3-4, the NO_X, SO_2, total PM, total PM_{10}, total $PM_{2.5}$, H_2SO_4, and CO_2e emissions increases are less than the applicable major modification thresholds, and thus, NSR permitting is not required for these pollutants. However, the CO emissions increases exceed the applicable PSD major modification threshold, and thus NSR permitting is required for CO.

3.4 HAP AND TAP EMISSIONS

GPI has estimated HAP and toxic air pollutant (TAP) emissions from the proposed new equipment and changes to existing units and determined that increases in emissions will result from the proposed project.[23] Specifically, GPI calculated HAP emissions from the No. 3 Biomass Boiler and No. 2 Power Boiler and emissions decreases from the No. 1 Power Boiler.

The potential emissions from the No. 3 Biomass Boiler for each pollutant were assumed to be the maximum emissions of the potential fuel firing scenarios. Emission factors for the No. 3 Biomass Boiler were estimated based on a combination of emission factors established by the U.S. EPA, proposed emissions limits, and GPI refined emission factors. Potential hydrogen chloride (HCl) emissions were based on an annual emission limit of 9.9 tpy. For select organic pollutants for which GPI felt AP-42 overestimated emissions (acetaldehyde, acrolein, benzene, formaldehyde, hydrogen fluoride [note an AP-42 factor is not listed for this pollutant], styrene, and toluene) custom factors were developed that were specific to fluidized bed boilers based on data from the AP-42 background database, original Boiler Maximum Achievable Control Technology (MACT) database from 2000, and reproposed Boiler MACT database from 2010. Similarly, GPI also evaluated a custom factor for manganese that considered only emissions from boilers in the 2010 Boiler MACT database that employ ESPs or baghouses. Note that AP-42 factors are dominated by stoker boilers, yet fluidized bed combustion boilers have better combustion characteristics and thus fewer organics emissions. In addition, the AP-42 factors are dominated by units employing multiclones and/or scrubbers, but ESPs and baghouses provide superior PM and inorganic HAP/TAP control. Refer to Appendix B for a detailed summary of the emission factor refinements. Potential emissions of all other HAP were estimated based on emission factors per U.S. EPA's AP-42 Sections 1.4 and 1.6.[24] The sum of all HAP potential emissions from the No. 3 Biomass Boiler are 22.46 tpy, and the maximum potential emissions from any individual HAP are 9.9 tpy HCl.

Past actual emissions from the combustion of coal, fuel oil, and natural gas for the No. 1 Power Boiler and No. 2 Power Boiler and future potential emissions from the combustion of natural gas from the No. 2 Power Boiler were estimated as discussed in Section 3.2.2.

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[23] GPI will submit a toxics impact analysis under separate cover to demonstrate that the increases in certain TAP will not cause adverse impacts according to the *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* published by Georgia EPD in June 21, 1998.

[24] U.S. EPA's AP-42 Section 1.4, *Natural Gas,* dated July 1998, and Section 1.6, *Wood Residue Combustion in Boilers,* dated September 2003.

4. FEDERAL REGULATORY APPLICABILITY ANALYSIS

The Macon Mill is subject to certain federal and state air regulations. This section of the application summarizes the air permitting requirements and key air quality regulations that apply to the facility under both federal and state permitting programs. Federal permitting programs comprise requirements for construction of new sources or modification of existing sources (NSR, including implications of the new Tailoring Rule) and for operation of major sources of air pollutants (Title V Operating Permit Program). The applicability and requirements of these programs are discussed in the following sections.

GPI also assessed the potential applicability of regulatory requirements for the proposed project under the following programs: New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), Acid Rain Program (ARP), Clean Air Interstate Rule (CAIR), and the proposed Transport Rule.

4.1 U.S. EPA'S TAILORING RULE

On May 13, 2010, the U.S. EPA issued the Tailoring Rule which establishes an approach to addressing GHG from stationary sources under the Clean Air Act (CAA) permitting programs (PSD and Title V).[25] GHG become subject to regulation under the CAA on January 2, 2011 when U.S. EPA's Light Duty Vehicle Rule takes effect. Recognizing that the existing statutory major source thresholds established under the CAA of 100 and 250 tpy for regulated pollutants, while appropriate for criteria pollutants, are not feasible for GHG which are emitted in much higher volumes, the U.S. EPA is phasing in the CAA permitting of GHG sources via this rule. The rule establishes a schedule for the phase-in of CAA permitting requirements for GHG via two initial steps: Step 1 - For the time period from January 2, 2011 through June 30, 2011; and Step 2 - For the time period from July 1, 2011 through June 30, 2013.

4.1.1 TITLE V PERMITTING IMPLICATIONS

With respect to Title V permitting, starting January 2, 2011, sources that are required to have Title V permits due to potential emissions of non-GHG pollutants, are required to address GHG when applying for, renewing, or revising their permits. In Step 2, starting July 1, 2011, sources with a potential to emit greater than or equal to 100,000 tons per year CO_2e will be considered a major source under Title V and will be required to obtain a permit if they do not already have one.

The Macon Mill has an existing Title V permit. Therefore, GPI has included relevant CO_2e emissions as part of this application related to units impacted by the proposed project.

[25] Rule was published in the Federal Register on June 3, 2010, and became effective August 2, 2010. Federal Register Vol. 75, No. 106, June 3, 2010, pages 31541 – 31608. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf

4.1.2 MAJOR NSR PERMITTING IMPLICATIONS

The Tailoring Rule also addresses PSD permitting with respect to GHG emissions. The rule establishes multiple implementation phases (i.e., steps) for PSD permitting for GHG. The applicable implementation phase depends on the date that the final permit is issued. Step 1 and Step 2 of the PSD permitting program for GHG under the Tailoring Rule each establish unique applicability criteria, as described below.

The Step 1 phase of the Tailoring Rule implementation applies to final PSD permits issued on or after January 2, 2011 but before July 1, 2011. An existing major PSD source for non-GHG pollutants will trigger PSD permitting for GHG under Step 1 if a proposed project meets the following three criteria:

1. A PSD significant net emissions increase is projected for at least one non-GHG pollutant (i.e., a non-GHG pollutant triggers PSD permitting);
2. A GHG emissions increase (or net emissions increase) of 0 tpy or more is projected, calculated as the sum of six well-mixed GHG on a mass basis (e.g., GWPs are not applied to each GHG); and
3. A GHG emissions increase (or net emissions increase) of 75,000 tpy CO_2e or more is projected, calculated as the sum of six well-mixed GHGs on a CO_2e basis (e.g., GWPs are applied to each GHG to determine CO_2e emissions).

Since dispersion modeling is not required for GHG under the PSD program, PSD permitting for GHG focuses on BACT assessments. As demonstrated in Section 3.3 this project triggers PSD permitting for CO and therefore is subject to the GHG PSD permitting (e.g., BACT) requirements under Step 1 of the Tailoring Rule.

4.1.3 DEFERRAL FOR BIOGENIC SOURCES

On July 20, 2011, U.S. EPA published a rulemaking to defer GHG permitting requirements for three years for CO_2 emissions from biomass-fired and other biogenic sources.[26] The purpose of the deferral is to allow for additional time for U.S. EPA to seek further independent scientific analysis, complete a detailed examination of the science associated with biogenic CO_2 emissions, and consider the technical issues the agency must resolve to account for biogenic CO_2 emissions in ways that are both scientifically sound and manageable in practice. U.S. EPA intends to then issue a second rulemaking with a determination of how to account for CO_2 emissions from biogenic sources under GHG permitting requirements. Accordingly, biogenic CO_2 emissions are excluded from the project CO_2e emissions.

4.2 NEW SOURCE REVIEW – REGULATED POLLUTANTS OTHER THAN GHG

The NSR permitting program generally requires a source to obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results

[26] Federal Register Vol. 76, No. 139, July 20, 2011.

in the potential to emit air pollution in excess of certain threshold levels. The NSR program is comprised of two elements: NNSR and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area the facility is located is classified as "nonattainment" for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as "attainment" or "unclassifiable".

The Macon Mill is located in Bibb County, which has been designated as "attainment" or "unclassifiable" for all criteria pollutants except $PM_{2.5}$.[27] Therefore, modifications made to the facility are potentially subject to PSD permitting requirements for all pollutants covered under this program except $PM_{2.5}$.

Note that while formal designations for the new 1-hour National Ambient Air Quality Standard (NAAQS) for NO_2, effective January 22, 2010, have not yet been completed, 2006-2008 monitor information available for Georgia indicates that existing monitors do not indicate any NAAQS exceedances (i.e., no nonattainment areas).[28] Similarly, designations have not been completed for the new 1-hour SO_2 NAAQS, effective August 23, 2010, but it is unlikely that Bibb County would have SO_2 emissions causing or contributing to a NAAQS violation based on 2007-2009 monitor data for Georgia.[29] Lastly, U.S. EPA has also proposed revisions to the existing 8-hour ozone NAAQS. Based on the proposed range of values, the Macon area may be determined to be nonattainment; however, the designations will be based on more recent data and are not expected to be in effect until after issuance of the permit for the proposed project.[30] Therefore PSD permitting is currently still evaluated for these pollutants.

The PSD program only regulates emissions from "major" stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant exceed the major source thresholds. The PSD major source emission threshold is 250 tpy of a non-GHG criteria pollutant unless the source belongs to one of 28 specifically defined industrial source categories for which the major source threshold is 100 tpy.[31] Pulp and paper mills are included in the "List of 28"; thus, the PSD major source threshold for the Macon Mill is 100 tpy. The Macon Mill's potential emissions of non-GHG PSD regulated pollutants exceed 100 tpy for several pollutants.[32]

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[27] 40 CFR 81.311

[28] http://www.epa.gov/air/nitrogenoxides/pdfs/NO2_final_designvalues_0608_Jan22.pdf Values shown are for the metro-Atlanta area, which is expected to have higher background NO_X emissions than Bibb County due to the mobile sources present in Atlanta.

[29] http://www.epa.gov/airquality/sulfurdioxide/pdfs/20100602table0709.pdf Value shown for Bibb County is well below the 75 ppb standard and would not be expected to increase to above 75 ppb when using a more recent 3-year period.

[30] http://www.epa.gov/air/ozonepollution/pdfs/CountyPrimaryOzoneLevels0608.pdf

[31] 40 CFR 52.21(b)(1)(i)(a)

[32] The PSD program regulates the emissions of all criteria pollutants and several non-criteria pollutants such as total reduced sulfur compounds, sulfuric acid mist, and fluorides (not including hydrogen fluoride).

The NNSR program regulates emissions increases of only those pollutants for which the area is designated as nonattainment. In 2004, Bibb County was designated as a $PM_{2.5}$ nonattainment area. In May 2008, U.S. EPA promulgated a rule to implement the NSR program for $PM_{2.5}$.[33] The rule specifies $PM_{2.5}$ includes both directly emitted $PM_{2.5}$ (primary $PM_{2.5}$) and its precursors, including SO_2 and NO_X. The Macon Mill potential $PM_{2.5}$ emissions exceed the 100 tpy major source threshold, making it a major NNSR source for $PM_{2.5}$.

In addition to criteria pollutants, NSR requires evaluation of other "regulated" pollutants such as H_2SO_4 and fluorides. Fluorides in general are regulated under PSD. However, since hydrogen fluoride (HF) is on the CAA Section 112(b)(1) HAP list, emissions of HF are not regulated via PSD. Thus, the PSD-regulated pollutant related to fluorine is fluorides except HF.[34] For combustion sources, most or all of the fluorine compounds emitted are expected to be in the form of HF, which is not regulated under PSD.

As the Macon Mill is a major PSD source and a major NNSR source for $PM_{2.5}$, the net emissions increase from the proposed project must be compared to the major modification thresholds to determine if PSD or NNSR permitting is required. The net emission increase analysis was presented in Sections 3.2 and 3.3 of this report. Table 4-1 presents a summary of the analysis.

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[33] 73 Federal Register Vol. 73, No. 96, May 16, 2008, p. 28321-28350.

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

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

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

TABLE 4-1. PROPOSED PROJECT NET EMISSION INCREASES

Pollutant	Emissions (tpy)	NSR Major Modification Threshold (tpy)	Exceed NSR Threshold? (Yes/No)
Project Potential Emissions Increases			
VOC	30.5	40	No
Pb	0.1	0.6	No
H_2S	-	10	No
Fluoride[1]	-	3	No
Net Emissions Increase			
CO	421.7	100	Yes
NO_X	38.3	40	No
SO_2	-459.9	40	No
Total PM	-13.9	25	No
Total PM_{10}	14.5	15	No
Total $PM_{2.5}$	9.6	10	No
H_2SO_4	6.9	7	No
CO_2e[2]	68,649.5	75,000	No

1. Excluding hydrogen fluoride, which is regulated per Clean Air Act Section 112.

2. NSR permitting for greenhouse gases (i.e., CO_2e) is required if NSR permitting is triggered for any other pollutant and the permit application is submitted after January 2, 2011 but before July 1, 2011. CO_2e emissions exclude biogenic CO_2 emissions per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

As illustrated in Table 4-1, the proposed project net emission increases exceed the major modification threshold for CO. Accordingly, PSD permitting is required for this pollutant.

4.3 NEW SOURCE PERFORMANCE STANDARDS

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions.

4.3.1 40 CFR 60 SUBPART A, GENERAL PROVISIONS

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

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

NSPS Subpart D, *Standards of Performance for Fossil Fuel Fired Steam Generators for which Construction is Commenced after August 17, 1971*, provides standards of performance for fossil fuel-fired and wood-fired steam generating units for which construction commenced after August 17, 1971.[35] This subpart applies to steam generating units having a maximum rated heat input capacity in excess of 250 MMBtu/hr from fossil fuel.

Although the proposed No. 3 Biomass Boiler will have a maximum heat input capacity greater than 250 MMBtu/hr, can combust fossil fuel, and will be constructed after 1971, it is not subject to NSPS Subpart D since NSPS Subpart Db will apply to the proposed boiler. NSPS Subpart Db states in 40 CFR 60.40b(j) that any unit subject to Subpart Db that was constructed, modified, or reconstructed after June 19, 1986, is not subject to Subpart D. Furthermore, the No. 3 Biomass Boiler will be limited to a maximum fossil fuel heat input less than 250 MMBtu/hr, and the No. 3 Biomass Boiler will not meet the affected source definition.[36]

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

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978*, applies to electric utility steam generating units with capacities greater than 250 MMBtu/hr of fossil fuel for which construction, modification, or reconstruction commenced after September 18, 1978.[37,38] 40 CFR 60.41a defines an electric utility steam generating unit (EUSGU) as "constructed for the purpose of supplying more than one-third of its potential electric output capacity [PEOC] and more than 25 MW net electrical output [gross electric sales to the utility power distribution system minus purchased power] to any utility power distribution system for sale."

As the Macon Mill will potentially sell electricity to the grid upon completion of this project, applicability of NSPS Subpart Da must be considered for the proposed No. 3

[35] 40 CFR 60.40(a)

[36] The worst-case short-term heat input capacity is three startup burners (total 135 MMBtu/hr) and one load burner (122 MMBtu/hr) firing simultaneously; however, GPI will restrict burner operation such that the total natural gas heat input capacity is less than 250 MMBtu/hr.

[37] 40 CFR 60.40a(a)

[38] U.S. EPA has clearly defined the applicability requirement that fossil fuel capability must exceed 250 MMBtu/hr. Refer to U.S. EPA ADI Control Number NB12, a letter from Rizalino Castanares regarding the Detroit Resource Recovery Facility, dated April 3, 1986.

Biomass Boiler. An analysis is also presented for the No. 2 Power Boiler, although the unit is not technically being modified per the NSPS definition:[39]

- The No. 2 Power Boiler is rated at 198 MMBtu/hr and was constructed in the late 1940s and has not been modified or reconstructed after September 18, 1978. This unit is clearly not an EUSGU under NSPS Subpart Da since it does not meet the minimum fossil fuel heat input capacity requirement of 250 MMBtu/hr.
- The No. 3 Biomass Boiler will provide dedicated steam to the proposed 40 MW steam turbine. The PEOC for the proposed No. 3 Biomass Boiler is 60.6 MW; making it capable of generating more than 25 MW of electricity for sale to the grid.[40] One-third of the PEOC is 20.2 MW. Therefore, the No. 3 Biomass Boiler could potentially provide more than 25 MW net electrical output to the utility grid as well as one-third of its PEOC, although it is not being constructed for that purpose. Additionally, the No. 3 Biomass Boiler will be limited to a maximum heat input capacity of natural gas not to exceed 249 MMBtu/hr. Therefore, since potential fossil fuel heat input is less than 250 MMBtu/hr, the new boiler will not be an EUSGU under NSPS Subpart Da.

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

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[41] The proposed No. 3 Biomass Boiler will be constructed after 1984, will have a heat input capacity greater than 100 MMBtu/hr, and will generate steam. The proposed No. 3 Biomass Boiler will be subject to the more stringent requirements of the standard as it is being constructed post-February 2005. Table 4-2 presents a summary of the potentially applicable requirements of NSPS Subpart Db for the proposed boiler.

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[39] Per 40 CFR 60.2, modification means *any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted*.

[40] PEOC is estimated per 40 CFR 60.41a(a) based on the following equation (where Q is the maximum design heat input capacity):

$$PEOC = \left(\frac{Q}{3}\right)\left(\frac{10^6\,\text{Btu}}{\text{MMBtu}}\right)\left(\frac{1\text{kW}-\text{hr}}{3{,}413\text{Btu}}\right)\left(\frac{1\text{MW}}{1{,}000\text{kW}}\right)$$

[41] 40 CFR 60.40b(a)

TABLE 4-2. NSPS SUBPART DB APPLICABLE REQUIREMENTS

Pollutant	Limitation	Monitoring	Notes
PM[1]	0.030 lb/MMBtu	PM CEM (PS-11) or COMS (PS-1)	
Opacity	20% except for one 6-minute period per hour of not more than 27%	Refer to PM requirements	
SO_2 – natural gas only	N/A	Fuel records, site-specific weekly fuel analysis	Exemption from limit per 40 CFR 60.42b(k)(2)
SO_2 – natural gas mixed with fuels with potential $SO_2 \leq$ 0.32 lb/MMBtu	N/A		Exemption from limit per 40 CFR 60.42b(k)(2)
SO_2 – natural gas mixed with fuels with potential uncontrolled SO_2 > 0.32 lb/MMBtu[2]	0.20 lb/MMBtu	SO_2 CEM (PS-2, PS-3)	
NO_X – 10% fossil fuel annual capacity limit	N/A	Fuel records	Capacity limit applies to coal, oil, and natural gas.
NO_X – no fossil fuel annual capacity limit[3]	0.20 lb/MMBtu	NO_X CEMS	

1. PM requirements per 40 CFR 60.43b(f)-(h). The limitations apply at all times except startup, shutdown, or malfunction.
2. Per 40 CFR 60.42b(k)(1), an SO_2 limit of 0.20 lb/MMBtu applies when combusting "coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels." 30-day rolling average.
3. NO_X limitations per 40 CFR 60.44b(l)(1). 30-day rolling average.

The No. 3 Biomass boiler will be subject to the PM emission standard of 0.030 lb/MMBtu and the opacity standard of 20% (except for one 6-minute period per hour of not more than 27%). These limits apply at all times except during periods of startup, shutdown or malfunction. A continuous opacity monitoring system (COMS) will be installed per the requirements of NSPS Subpart Db.

If natural gas is not combusted with other fuels, there is clearly no SO_2 limitation. If natural gas is combusted with a mixture of other fuels, the uncontrolled potential emissions of SO_2 dictate applicability of the 0.20 lb/MMBtu SO_2 requirement. Anticipated uncontrolled emissions from the mixture of biomass, sludge, and natural gas will be less than or equal to the threshold of 0.32 lb SO_2/MMBtu. The proposed No. 3 Biomass Boiler will not be able to combust natural gas with mill sludge only. Accordingly, the No. 3 Biomass Boiler is not subject to an SO_2 emission standard per this subpart. GPI will be required to develop a site-specific fuel analysis plan for review and approval at least 60 days prior to demonstrating compliance. The plan must include a minimum initial requirement of weekly testing and each analysis report must demonstrate the potential emissions rate of the representative fuel mixture, the methodology employed, and the ratio of fuels in the fuel mixture.[42] GPI will likely petition for approval of monthly or quarterly sampling in lieu of weekly sampling as allowed per 40 CFR 60.49b(r)(2)(iv).

[42] 40 CFR 60.45b(k), 40 CFR 60.49(r)(2)(i)–(iii).

With respect to the NO_X requirements, GPI is requesting a 10% annual capacity factor for fossil fuel (i.e., natural gas) for the proposed No. 3 Biomass Boiler. Accordingly, there is no applicable NO_X emission limit per NSPS Subpart Db, and the Macon Mill will retain required fuel records needed to calculate the fossil fuel annual capacity factor.

The No. 2 Power Boiler is presently not subject to the requirements of NSPS Subpart Db. As the proposed project is removing the capability of the unit to combust coal and oil, but retaining natural gas capability, there will not be an increase in short-term emissions resulting from the proposed changes. Accordingly, the No. 2 Power Boiler is not undergoing a modification as defined per 40 CFR 60.2, and the unit is not subject to the requirements of NSPS Subpart Db.[43]

4.3.5 40 CFR SUBPART E, INCINERATORS

NSPS Subpart E, *Standards of Performance for Incinerators*, is applicable to incinerators charging more than 50 tons/day and that were constructed after August 17, 1971. 40 CFR 60.51(a) specifically defines an incinerator as "any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste," while solid waste is defined in 40 CFR 60.51(b) as "refuse, more than 50 percent of which is <u>municipal type</u> waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles and noncombustible materials such as glass and rock."

U.S. EPA also has determined that materials without any noncombustibles do not constitute solid waste and are not subject to NSPS Subpart E.[44] Thus, waste must be a mixture of materials, combustible and noncombustible, to be considered solid waste. In this regard, the new No. 3 Biomass Boiler will not combust any solid waste and thus does not meet the definition of an incinerator under NSPS Subpart E and is not subject to this subpart.

4.3.6 40 CFR SUBPART EB, LARGE MUNICIPAL WASTE COMBUSTORS

NSPS Subpart Eb, *Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for which Modification or Reconstruction is Commenced After June 19, 1996*, applies to municipal waste combustor units with capacities greater than 250 tons per day of municipal solid waste.

As discussed previously, the new No. 3 Biomass Boiler will not combust any municipal solid waste as determined by U.S. EPA and thus will not be subject to this subpart.

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[43] Per 40 CFR 60.2, modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

[44] Refer to U.S. EPA ADI Control Number EO14, a letter from Mr. Edward Reich to Mr. Dennis Santella, dated May 10, 1978.

4.3.7 40 CFR 60 Subpart O, Sewage Treatment Plants

NSPS Subpart O, *Standards of Performance for Sewage Treatment Plants*, is applicable to incinerators combusting wastes containing more than 10 percent sewage sludge produced by a municipal WWTP or each incinerator that charges more than 2,205 lb/day of municipal sewage sludge (dry basis) and commences construction or modification after June 11, 1973.

The new No. 3 Biomass Boiler will not combust any municipal sewage sludge and therefore will not be subject to this subpart.

4.3.8 40 CFR 60 Subpart BB, Kraft Pulp Mills

NSPS Subpart BB, *Standards of Performance for Kraft Pulp Mills*, provides performance standards for emission units at Kraft pulp mills, including the digester system, brownstock washer system, multiple-effect evaporator system, recovery boiler, smelt dissolving tank, lime kiln, and condensate stripper system (including the stripper condenser, feed tank, and column, condensate tanks). Applicability is limited to emission units constructed or modified after September 24, 1976.[45]

The proposed No. 3 Biomass Boiler will not be used for the combustion of the total reduced sulfur-containing (TRS) process gases required to be collected and destroyed for subject sources at the Mill. Accordingly, NSPS Subpart BB will not apply to the proposed boiler or other equipment being proposed as part of the project.

4.3.9 40 CFR 60 Subpart GG, Stationary Gas Turbines

NSPS Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired that are constructed, modified, or reconstructed after October 3, 1977.[46] As the proposed new turbine will be a steam turbine not a combustion turbine, this subpart will not apply to the steam turbine.

4.3.10 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants

NSPS Subpart OOO, *Standards of Performance for Nonmetallic Mineral Processing Plants*, establishes requirements for affected facilities being constructed on or after August 31, 1983 (note separate requirements apply to sources constructed, reconstructed or modified after April 22, 2008).[47] An affected facility in this subpart is defined as a facility that uses any combination of equipment to crush or grind any nonmetallic material.

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[45] 40 CFR 60.280

[46] 40 CFR 60.330(a), (b)

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

GPI is evaluating various designs related to the sorbent injection system. Presently, GPI does not anticipate that the sorbent injection system will include any crushing or grinding operations; rather, GPI will purchase sorbent sized appropriately for the injection system. In this scenario, the affected facility definition under Subpart OOO will not be met, and this Subpart will not apply. Should GPI opt to pursue a system with grinding, applicability of Subpart OOO will be reassessed and Georgia EPD notified of possible changes.

4.3.11 40 CFR 60 SUBPART AAAA, SMALL MUNICIPAL WASTE COMBUSTION UNITS

NSPS Subpart AAAA, Standards of Performance for Small Municipal Waste Combustion Units for which Construction is Commenced After August 30, 1999 or for which Modification or Reconstruction is Commenced After June 6, 2001, establishes requirements for planning, constructing, and operating a small municipal waste combustion unit.

As discussed previously, the new No. 3 Biomass Boiler will not combust any municipal solid waste as determined by U.S. EPA and thus will not be subject to this subpart.

4.3.12 40 CFR 60 SUBPART CCCC, COMMERCIAL AND INDUSTRIAL SOLID WASTE INCINERATORS

On March 21, 2011, U.S. EPA published three related final rules, intended to reduce the emission of HAP from industrial, commercial, and institutional boilers and process heaters as well as commercial and industrial solid waste incinerators (CISWI).[48] Simultaneously, U.S. EPA also finalized a definition of solid waste that would dictate applicability of the CISWI NSPS requirements in lieu of NESHAP established per Section 112 of the Clean Air Act for boilers combusting solid waste (40 CFR Part 241).[49] These actions replace the NESHAP for new and existing boilers and process heaters that was previously promulgated in 2004 and vacated by the court in 2007. The newly finalized rules include:

- NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT)
- NESHAP for Area Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Area Source Boiler MACT)
- Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units (CISWI Rule; NSPS Subpart CCCC)

[48] *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units* (CISWI standards), published in the Federal Register on March 21, 2011 (Volume 76, No. 54, pages 15704 – 15790).

[49] *Identification of Non-Hazardous Secondary Materials that are Solid Waste* (solid waste definition), as published in the Federal Register on March 21, 2011 (Volume 76, No. 54, pages 15456 – 15551).

On May 18, 2011, the effective dates of the Boiler MACT and CISWI Rule were stayed pending reconsideration of elements of the regulations.[50,51] However, the definition of solid waste per 40 CFR Part 241 remains final, and units which combust solid waste will be applicable to the requirements of CISWI once the rule becomes effective. The definitions of 40 CFR 241 Subpart A clearly state that traditional fuels as defined within the Part are not solid wastes. Natural gas and cellulosic biomass qualify as traditional fuels according to the following definition per 40 CFR 241.2:

> *Traditional fuels means materials that are produced as fuels and are unused products that have not been discarded and therefore, are not solid wastes, including: (1) Fuels that have been historically managed as valuable fuel products rather than being managed as waste materials, including fossil fuels (e.g., coal, oil and natural gas), their derivatives (e.g., petroleum coke, bituminous coke, coal tar oil, refinery gas, synthetic fuel, heavy recycle, asphalts, blast furnace gas, recovered gaseous butane, and coke oven gas) and cellulosic biomass (virgin wood); and (2) alternative fuels developed from virgin materials that can now be used as fuel products, including used oil which meets the specifications outlined in 40 CFR 279.11, currently mined coal refuse that previously had not been usable as coal, and clean cellulosic biomass. These fuels are not secondary materials or solid wastes unless discarded.*

40 CFR 241.2 also includes a definition for clean cellulosic biomass which is one of the alternative fuels which are also not considered solid waste:

> *Clean cellulosic biomass means those residuals that are akin to traditional cellulosic biomass such as forest-derived biomass (e.g., green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials), corn stover and other biomass crops used specifically for energy production (e.g., energy cane, other fast growing grasses), bagasse and other crop residues (e.g., peanut shells), wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, clean biomass from land clearing operations, and clean construction and demolition wood. These fuels are not secondary materials or solid wastes unless discarded. Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials.*

The proposed No. 3 Biomass Boiler will burn cellulosic biomass (i.e., virgin wood) and clean cellulosic biomass material which are each considered a non-solid waste material. In addition to biomass, GPI is also proposing to combust pulp and paper mill residuals (i.e., mill WWTP sludge). Pulp and paper mill residuals are not considered a traditional fuel. 40 CFR 241.3(b) identifies the non-hazardous secondary materials that are not considered

[50] Federal Register Volume 76, No. 96, pages 28662 – 28664, published on May 18, 2011.

[51] Note the effective date of the Area Source Boiler MACT was not delayed.

solid wastes when combusted. For the purpose of determining if mill WWTP sludge is considered a solid waste, 40 CFR 241.3(b)(i) is critical:

> *(b) The following non-hazardous secondary materials are not solid wastes when combusted:*
>
> > *(1) Non-hazardous secondary materials used as a fuel in a combustion unit that remain within the control of the generator and that meet the legitimacy criteria specified in paragraph (d)(1) of this section.*

Accordingly, to be excluded as a solid waste, the sludge must remain within the control of the generator AND meet the "legitimacy criteria". The legitimacy criteria for fuel include the following elements as specified in 40 CFR 241.3(d)(1):

1. Manage as a valuable commodity (storage on-site limited to a reasonable timeframe, handled to prevent loss of material)
2. Have meaningful heat content (not defined, U.S. EPA possibly considering greater than 5,000 Btu/lb, although methods are available for documenting that fuel with a heat content less than that provides heat input of value to the energy recovery unit)
3. Contain contaminants at levels comparable to or lower than those of traditional fuels the unit is designed to burn. Note this is not an emissions comparison, but a comparison of what the fuel contains. "Contaminants" means any of the Section 112(b) pollutants or the Section 129(a)(4) pollutants.

If it is determined that WWTP sludge is not considered a solid waste, GPI will proceed with combustion of these residuals in the proposed No. 3 Biomass Boiler. However, if pulp and paper mill residuals are classified as solid waste, GPI will not combust the sludge in the proposed No. 3 Biomass Boiler. <u>In short, the intended applicability is for the proposed No. 3 Biomass Boiler to not be subject to the requirements of CISWI, but instead be regulated by the Boiler MACT</u>. Therefore, this application is submitted based on the presumption that CISWI does not apply to the No. 3 Biomass Boiler, but Boiler MACT will apply when finalized.

4.3.13 40 CFR 60 SUBPART EEEE, OTHER SOLID WASTE INCINERATION UNITS

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

As discussed previously, the new No. 3 Biomass Boiler will not combust any municipal solid waste as determined by U.S. EPA and thus will not be subject to this subpart. Further, the new No. 3 Biomass Boiler will be subject to 40 CFR 63 Subpart DDDDD (proposed). 40 CFR 60.2887 of Subpart EEEE specifically exempts boilers that are regulated under 40 CFR 63 Subpart DDDDD. As such, the No. 3 Biomass Boiler will not be subject to NSPS Subpart EEEE.

4.3.14 40 CFR 60 Subpart KKKK, Stationary Combustion Turbines

NSPS Subpart KKKK, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18, 2005.[52] Since the proposed new turbine will be a steam turbine not a combustion turbine, Subpart KKKK will not apply to the unit.

4.4 National Emission Standards for Hazardous Air Pollutants

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

4.4.1 40 CFR 61 Subpart A, General Provisions

40 CFR 61 Subpart A provides the general provisions for which each source subject to another Part 61 subpart must comply unless specifically excluded by the applicable subpart. These provisions include initial notification and performance testing, recordkeeping, and monitoring requirements for all other subparts as applicable.

4.4.2 40 CFR 61 Subpart E, Mercury

40 CFR 61 Subpart E, *National Emission Standard for Mercury*, limits mercury emissions from several types of operations including combustion of WWTP sludge. The new No. 3 Biomass Boiler will combust sludge from the Mill's WWTP. Accordingly, the boiler will be subject to the requirements of 40 CFR 61 Subpart E. This regulation limits mercury emissions from the new No. 3 Biomass Boiler to 7.1 pounds per 24-hour period.[53]

Subpart E requires that GPI complete initial stack testing or sludge sampling within 90 days of startup. Additional compliance testing may also be required based on the results of the initial testing. GPI intends to conduct sludge test sampling per the requirements of 40 CFR 61.54.

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[52] 40 CFR 60.4305(a), (b)

[53] 40 CFR 61.52(b)

4.4.3 40 CFR 61 SUBPART M, ASBESTOS

40 CFR 61 NESHAP Subpart M, *National Emission Standards for Asbestos,* applies to various industrial facilities that handle, process, or manufacture asbestos. 40 CFR 61.145, the only Subpart M provision potentially applicable to the Mill, applies to the owner or operator of a demolition or renovation activity where asbestos may be disturbed. When the Macon Mill engages in demolition or renovation activities involving asbestos, activities must be completed in full compliance with the provisions of 40 CFR 61.145. GPI does not anticipate any activities involving asbestos as part of the proposed construction activities.

4.4.4 40 CFR 63 SUBPART A, GENERAL PROVISIONS

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

4.4.5 40 CFR 63 SUBPART B, 112(G) CASE-BY-CASE MACT

Section 112(g) of the 1990 Clean Air Act Amendments (codified at 40 CFR 63 Subpart B, *Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections*), is known as the case-by-case MACT. The NESHAP regulating boilers (Subpart DDDDD) has been vacated and specific standards are not yet promulgated.[54] Thus, at this time, case-by-case MACT is potentially applicable to new boilers. Case-by-case MACT is applicable to newly constructed major sources of HAP emissions. "Construct a major source" is defined as follows per Subpart B:[55]

> *… (2) To fabricate, erect, or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP, ….*

Therefore, to be subject to the case-by-case MACT requirement, HAP emissions from the No. 3 Biomass Boiler alone must be major. As discussed previously in this application, anticipated HAP emissions from the No. 3 Biomass Boiler do not exceed the 10/25 tpy HAP major source thresholds. Therefore, case-by-case MACT does not apply to the proposed boiler.

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[54] U.S. EPA reproposed the Boiler MACT rule in the Federal Register on June 4, 2010. *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (proposed Boiler MACT), (Volume 75, No. 107, pages 32006 – 32073). However, the final rule has yet to be promulgated, but is anticipated per court order by February 21, 2011. Therefore, while the No. 3 Biomass Boiler is anticipated to be regulated via the Boiler MACT, the requirements are not yet promulgated. GPI will update this application submittal following promulgation of the Boiler MACT standard.

[55] 40 CFR 63.41

4.4.6 40 CFR 63 Subpart Q, Cooling Towers

40 CFR 63 Subpart Q, *NESHAP for Industrial Process Cooling Towers*, applies to cooling towers operating with chromium-based water treatment chemicals that are located at facilities that are major sources of HAP. The new cooling tower water treatment chemicals will not be chromium based, and hence the facility will not be subject to this subpart.

4.4.7 40 CFR 63 Subpart S, Pulp and Paper Industry

40 CFR 63 Subpart S, *NESHAP from the Pulp and Paper Industry*, requires that various pulping process air emissions and process condensate emissions at pulp mills that are major HAP sources be collected and treated. The Macon Mill is a major source of HAP emissions, and therefore, is subject to the NESHAP Subpart S regulations.

Similar to NSPS Subpart BB, NESHAP Subpart S does not specifically list biomass boilers as affected sources or establish any emission limits. As GPI does not intend to use the proposed No. 3 Biomass Boiler for combustion of regulated process gases, Subpart S will not apply to the proposed boiler.

4.4.8 40 CFR 63 Subpart MM, Pulp Mill Recovery Combustion Sources

40 CFR 63 Subpart MM, *NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills*, requires the reduction of HAP emissions from the chemical recovery combustion sources at pulp mills that are major HAP sources. Biomass boilers are not affected sources under Subpart MM; therefore, no requirements under this rule will apply to the proposed boiler.

4.4.9 40 CFR 63 Subpart YYYY, Turbines

40 CFR 63 Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limits for stationary combustion turbines located at HAP major sources. Since the proposed new turbine will be a steam turbine, Subpart YYYY will not apply.

4.4.10 40 CFR 63 Subpart DDDDD, Industrial Boilers (Proposed)

40 CFR 63 Subpart DDDDD, *NESHAP for Industrial-Commercial-Institutional Boilers and Process Heaters* (Boiler MACT), was originally promulgated on September 13, 2004, and regulated HAP emissions from solid, liquid, and gaseous fuel-fired boilers and process heaters at facilities that are a major source of HAP. However, in June 2007, the U.S. Court of Appeals for the District of Columbia Circuit ruled to vacate Subpart DDDDD in its entirety, and the mandate was issued July 30, 2007.[56]

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

Boiler MACT was most recently finalized on March 21, 2011, with an effective date of May 20, 2011. However, on May 18, 2011, the effective date of the Boiler MACT was stayed pending reconsideration of elements of the regulation.[57] GPI will review applicability and requirements upon promulgation of the final standard following reconsideration and will comply with any requirements that are applicable.

4.5 COMPLIANCE ASSURANCE MONITORING

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

For an emission unit whose post-controlled emissions are greater than the major source thresholds (referred to as large pollutant-specific emission units [PSEU] in the rule) at a facility that already has a Title V operating permit, a CAM plan is required to be submitted with the next Title V operating permit significant modification application for the subject large PSEU(s) or with the next Title V operating permit renewal application, whichever is first. For emission units whose post-controlled emissions are less than the major source emission thresholds, a CAM plan is not required to be submitted until the next Title V operating permit renewal application.[58]

The proposed No. 3 Biomass Boiler has pre-controlled emissions greater than 100 tpy for NO_X, filterable PM, and total $PM_{10}/PM_{2.5}$ and will be subject to limits for these pollutants. Pre-controlled emissions of HCl will possibly be greater than 10 tpy, the single HAP major source threshold. If required, HCl emissions will be reduced via a sorbent injection system. SNCR will be used to reduce NO_X emissions and a baghouse will be used to control predominately filterable PM, with possible reductions of total $PM_{10}/PM_{2.5}$ emissions. As such, the boiler will require CAM Plans specific to NO_X, filterable PM, and total $PM_{10}/PM_{2.5}$, unless a specific exemption under 40 CFR 64.2(b) is met. None of the other NSR-regulated pollutants utilize a control device to meet an emission limit.

40 CFR 64.2(b) lists a number of exemptions from CAM applicability. Key exemptions considered include:

- Emission limits proposed by U.S. EPA after November 15, 1990 under Sections 111 or 112 of the Clean Air Act.
- Emission limits or standards for which a Title V operating permit specifies a continuous compliance demonstration method (i.e., continuous parameter, opacity, or emissions monitoring)

[57] Federal Register Volume 76, No. 96, pages 28662 – 28664, published on May 18, 2011.

[58] 40 CFR 64.5(a)-(b)

Any limits for the No. 3 Biomass Boiler that are exclusively from post-November 15, 1990 NSPS or NESHAP limits are excluded from CAM applicability (i.e., NSPS Subpart Db filterable PM limit for post-2005 units). However, additional PM related limit(s) will apply based on the GRAQC regulations and/or NSR-avoidance, and such limits are not excluded from CAM applicability. However, GPI will be utilizing continuous parameter monitoring systems, a COMS, to ensure compliance with the filterable PM and total $PM_{10}/PM_{2.5}$ limits, also meeting the continuous compliance demonstration method exemption. Therefore, the No. 3 Biomass Boiler will be exempt from CAM requirements for filterable PM and total $PM_{10}/PM_{2.5}$.

GPI is proposing to utilize a NO_X CEMS to demonstrate compliance with the proposed NO_X limit; usage of the CEMS will be included in the Title V operating permit, meeting the continuous compliance demonstration method exemption.

If duct sorbent injection is required to ensure HCl emissions remain below the required 10 tpy limit, GPI will be using a continuous parameter monitoring system to monitor the sorbent injection rate, meeting the continuous compliance demonstration method exemption. If duct sorbent injection is not used, CAM will not apply since a control device is not employed for HCl.

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

In the 2005 Title V operating permit renewal application, GPI documented the inapplicability of CAM to the existing Nos. 1 and 2 Power Boilers due to the continuous scrubber parameter monitoring. The inapplicability will remain in effect for the No. 2 Power Boiler upon removal of the coal and fuel oil combustion capabilities as part of this proposed project as the unit will no longer employ a control device.

4.6 RISK MANAGEMENT PROGRAM

Subpart B of 40 CFR Part 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at the facility. GPI has evaluated the amount of Section 112(r) substances currently stored at the facility and proposed to be stored upon completion of this proposed project. GPI is presently not subject to the RMP requirements of Part 68; however, the facility is subject to the provisions of the CAA General Duty Clause, Section 112, as it pertains to accidental releases of hazardous materials. GPI is assessing strategies related to storage of aqueous ammonia presently used on the paper machines and to be used for the SNCR on the proposed No. 3 Biomass Boiler. Aqueous ammonia with a concentration of 20% or greater stored in quantities exceeding

20,000 pounds is a listed substance per Part 68. As GPI finalizes plans for the concentration and on-site storage quantities of ammonia, RMP requirements will be reassessed.

4.7 ACID RAIN PROGRAM

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

40 CFR 72.6 defines affected sources under the ARP and also lists specific exemptions for cogeneration. The Macon Mill is not a listed source in Tables 1 or 2 of 40 CFR 73.10, and the facility does not currently generate electricity for sale. Electricity sales to the grid are being contemplated following completion of the proposed project. As the existing emission units at the Mill are all cogeneration units, the cogeneration exemption of 40 CFR 72.6(b)(4) must be evaluated:

> *A cogeneration facility which:*
>
> *(i) For a unit that commenced construction on or prior to November 15, 1990, was constructed for the purpose of supplying equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis).*
>
> *(ii) For units which commenced construction after November 15, 1990, supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis)*

Therefore, in order for a cogeneration unit to be affected by the ARP, the unit must combust fossil fuel (**<u>in any amount</u>**) and annual **<u>gross</u>** sales of more than 1/3 of the PEOC, totaling more than 219,000 MW-hr (equivalent to 25 MW), must be sold to the grid.[59] As the Macon Mill will potentially be distributing electricity for sale to the utility grid following this proposed project, applicability of the ARP to all possible affected sources, existing and proposed, must be evaluated at this time.

Existing cogeneration sources serving steam turbines at the Mill include the No. 2 Biomass Boiler, the Nos. 1 and 2 Power Boilers, and the No. 3 Recovery Boiler. All of these units have the ability to combust fossil fuel. The No. 2 Biomass Boiler and the Nos. 1 and 2 Power Boilers were all installed prior to November 15, 1990 and were constructed for the purpose of supplying steam and electricity to Mill processes. As these units have never sold electricity to the grid, they clearly do not meet the qualifying distinction for such units of being constructed *"for the purpose of supplying…electric*

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[59] The 219,000 MW-hrs value is arrived at by multiplying the minimum nameplate capacity subject to regulation (25 MW) by the number of hours in a year (8,760).

output…to any utility power distribution system for sale…" and therefore are exempt cogeneration units per 40 CFR 72.6(b)(4)(i).

The No. 3 Recovery Boiler is the only unit installed after November 15, 1990 and thus the "for the purpose of" qualifier does not apply. Steam generated by the No. 3 Recovery Boiler and the other existing Mill cogeneration sources feed a common multi-header steam system which then distributes steam to the four existing steam turbines at the Mill. As established in the U.S. EPA *Acid Rain Guidelines* for a multi-headered system, if the ratio of the total generator nameplate capacity to the combined PEOC is less than one-third of the combined PEOC, the units feeding the multi-headered system are generally not affected units under the ARP.[60] Table 4-3 provides the estimated combined PEOC and the resulting comparison to the total nameplate capacity for the existing units.

TABLE 4-3. COMBINED HEADER PEOC ESTIMATE

Unit	Heat Input Capacity (MMBtu/hr)	Individual PEOC[1] (MWe)	1/3 of Individual Unit PEOC (MWe)	1/3 of Individual Unit PEOC (MWe-hr)	Combined PEOC[2] (MWe)	Total Turbine Rating[3] (MWe)	1/3 of Combined PEOC (MWe)	1/3 of Combined PEOC (MWe-hr)
No. 1 Power Boiler	198	19.3	6.4	56,466	192	45	64.0	560,672
No. 2 Power Boiler	198	19.3	6.4	56,466				
No. 3 Recovery Boiler	1,050	102.5	34.2	299,443				
No. 2 Biomass Boiler	520	50.8	16.9	148,296				

1. PEOC is estimated per 40 CFR 72.2 and Appendix D to 40 CFR Part 72:

$$PEOC = \left(\frac{Q}{3}\right)\left(\frac{10^6\,\text{Btu}}{\text{MMBtu}}\right)\left(\frac{1\text{kW}-\text{hr}}{3{,}413\text{Btu}}\right)\left(\frac{1\text{MW}}{1{,}000\text{kW}}\right)$$

where Q represents the Maximum Designed Heat Input (MMBtu/hr).

2. Combined PEOC was estimated per guidance from *Do the Acid Rain SO_2 Regulations Apply to You? A Guide for Utilities and Other Electricity Generators*," EPA Office of Air and Radiation, Acid Rain Division, #430-R-94-002, February 1994, pg. 13.

3. Based on total of the existing 4 turbines as a common steam header and electricity distribution system are used.

As shown in Table 4-3, one-third of the combined PEOC exceeds the total turbine electricity generating capacity. Accordingly, the multi-header system is not capable of supplying more than one-third of its PEOC for sale to the utility grid. Accordingly, the No. 3 Recovery Boiler is also not subject to the requirements of the ARP as it meets the cogeneration unit exemption per 40 CFR 72.6(b)(4)(ii).

The No. 3 Biomass Boiler, which will be capable of combusting a fossil fuel, will provide dedicated steam to the proposed 40 MW steam turbine as well as process steam. The PEOC for the proposed No. 3 Biomass Boiler is 60.6 MWe; making it capable of generating more than 219,000 MWe-hr of electricity for sale to the grid.[61] One-third of the PEOC is 20.2 MWe (176,952 MWe-hr). As it is serving a turbine generator with a 40 MW nameplate capacity, it is capable of generating more than one-third of its PEOC for sale to the grid. Accordingly, GPI is requesting a direct electricity sales

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[60] U.S. EPA Office of Air and Radiation - Acid Rain Division, *Do the Acid Rain SO_2 Regulations Apply to You? A Guide for Utilities and Other Electricity Generators,* (Washington D.C.: U.S.EPA EPA-No. 430-R-94-002, February 1994), p. 13-14.

[61] 60.6 MWe * 8,760 hours/year = 530,856 MWe-hr.

limitation for the proposed No. 3 Biomass Boiler of 219,000 MWe-hr such that the unit qualifies for the cogeneration unit exemption. As electricity passing to the grid cannot presently be traced back to a specific generating unit, the proposed direct electricity sales limit is proposed as a facility-wide limit.

4.8 CLEAN AIR INTERSTATE RULE

CAIR, 40 CFR 96, calls for reductions in SO_2 and NO_X by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call/NO_X Budget program, and the name of 40 CFR 96 (NO_X Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

In general, a fossil fuel-fired emissions unit that serves a generator with a nameplate capacity of 25 MW or greater and sells any electricity is subject to CAIR.[62] However, if a unit qualifies as a cogeneration unit, it may sell up to one-third of the unit's PEOC, where PEOC is defined in an identical manner as under the ARP. However, there is a major distinction in the definition of a cogeneration unit under the ARP and under CAIR. Under ARP, a cogeneration unit is determined by what it is capable of doing. Under CAIR, a cogeneration unit is instead defined based on what a unit actually does. **Therefore, any limits taken to avoid ARP applicability also ensure the CAIR is avoided.**

The electricity limitation proposed for the No. 3 Biomass Boiler may not actually be required for avoidance of CAIR requirements. As promulgated, CAIR defined NO_X and SO_2 affected sources in 40 CFR 96.104(a) and 40 CFR 96.204(a), respectively, as "Except as provided in paragraph (b),…any stationary, fossil-fuel-fired boiler…serving at any time, since the later of November 15, 1990 or the startup of the unit's combustion chamber, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale." Exemptions in 40 CFR 96.104(b) and 40 CFR 96.201(b) include "qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity; and not…supplying in any calendar year more than one-third of the unit's potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale." A cogeneration unit is defined in 40 CFR 96.102 and 40 CFR 96.202 as follows:

> *A stationary, fossil-fuel-fired boiler... (1) having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and …(2)(ii) for a bottoming-cycle cogeneration unit [unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production], the useful power is not less than 45 percent of total energy input… (3) provided that the total energy input… shall equal the unit's total energy input from all fuels except biomass if the unit is a boiler.*

[62] 40 CFR 96.104(a), 40 CFR 96.204(a).

This definition did not originally include the biomass exemption; in October 2007, this definition was amended to specifically exclude biomass from the energy efficiency determination.[63] Given this biomass exclusion, the proposed No. 3 Biomass Boiler would potentially meet the cogeneration exemption included in CAIR.

Note the U.S Court of Appeals issued an opinion on July 11, 2008 that CAIR should be vacated.[64] As challenged by the State of North Carolina, the court determined that emission reductions or budgets must be directly tied to the impact of a specific state on a specific nonattainment area, not the region wide approach used by CAIR. While the court noted that one could arrive at the same conclusions via either method, the court believes that the state-by-state approach is mandated by the Clean Air Act. Following the logic of the court's state-by-state mandate, the court then noted that the emissions trading program is illegal. Further, the court noted that the Clean Air Act allows no consideration of equity when establishing state emission budgets, a challenge brought by power generators that primarily use gas or oil. Recognizing that it costs more to control a coal unit than an oil or gas unit, U.S. EPA discounted the emission budgets for gas or oil sources compared to coal sources. The court found U.S. EPA's fairness rationale arbitrary and unlawful and remanded CAIR to U.S. EPA without vacatur because it found that ''allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR.'' CAIR currently remains in effect then until the new Transport Rule (40 CFR 97) takes effect. (As proposed, sources subject to the Transport Rule will be required to comply by January 1, 2012 and January 1, 2014 for the first and second phases, respectively.)

4.9 TRANSPORT RULE

On August 2, 2010, U.S. EPA proposed the long awaited replacement for CAIR, which was rejected in 2008 by the D.C. Circuit Court of Appeals.[65] Now called the Transport Rule (TR), the new 40 CFR 97 Subparts AAAAA through DDDDD revise the CAIR approach to conform with the court ruling. In this first version (Round 1) of TR, overall emission budgets for NO_X are similar to the initial period in CAIR; overall SO_2 budgets are approximately 50% of the initial CAIR budget; and only utilities are regulated. However, U.S. EPA has stated its intention in Round 2 to revise TR at a minimum to consider additional NO_X reductions to assist at least two (likely three) metropolitan areas in meeting the 1997 ozone NAAQS of 0.08 ppm, for which an impact of 84 ppb was acceptable.

Unlike Round 1, Round 2 is expected to require many industrial NO_X emitters to reduce emissions.[66] Further, U.S. EPA has clearly designed TR to be readily adaptable to future NAAQS revisions and is

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[63] Federal Register Vol. 72, No. 202, October 19, 2007, pages 59190-59207.

[64] *State of North Carolina v. U. S. EPA*, U.S. Court of Appeals for the District of Columbia Circuit, No. 05-1244, decided July 11, 2008.

[65] Federal Register Vol. 75, No. 147, August 2, 2010, pages 45210 – 45465.

[66] U.S. EPA did not have adequate time to consider higher thresholds for the Round 1 rulemaking, and plans a future rulemaking to consider whether reductions at a higher cost per ton are appropriate for utilities and other source categories. Based on the current $500/ton threshold used for Round 1, all areas except Houston, TX and Baton Rouge, LA will be in attainment with the ozone NAAQS, while New York, NY flirts with nonattainment based on historical year-to-

defining the process for future TR versions in the initial rulemaking. As proposed, the TR only seeks to remove upwind pollution that "significantly contributes to or interferes with maintenance of" the 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS, and the 2006 24-hr $PM_{2.5}$ NAAQS, each of which is currently under review. A new ozone standard and new $PM_{2.5}$ standards are expected in 2011, which may lead to TR Round 3. U.S. EPA expects to propose revised TR requirements approximately one year after new NAAQS designations, with a final rule one year later.

As the TR is currently proposed, neither the existing units nor the proposed No. 3 Biomass Boiler at the Macon Mill are regulated sources for the same reason that CAIR does not currently apply (i.e., they meet the cogeneration unit exemption). Upon finalization of the rule (and upon finalization of subsequent revisions), GPI will reevaluate applicability.

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year ozone levels. For areas that contribute to Houston or Baton Rouge (and potentially areas that contribute to New York), U.S. EPA plans a review of additional reductions that could be achieved at more than $500/ton and at least up to $3,200/ton. At the highest cost thresholds, U.S. EPA expects to consider NO_X reductions from (1) industrial boilers, (2) reciprocating internal combustion engines (RICE), (3) portland cement manufacturing, (4) petroleum refining, (5) glass manufacturing, (6) pulp and paper production, and (7) iron and steel production.

In addition to federal air regulations, Georgia Rules for Air Quality Control (GRAQC) Chapter 391-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level. The rules also contain requirements related to the need for construction and/or operating permits.

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

This regulation limits the opacity from all sources to 40%, provided that the source is subject to some other emission limitation under GRAQC 391-3-1-.02(2).[67] The proposed No. 3 Biomass Boiler will be subject to another opacity limit under Rule (d); however, the proposed fly ash silo and fly ash handling units, bottom ash handling system, biomass handling units, sand storage and handling units, sorbent storage and handling units, hog tower, and proposed cooling tower will be subject to this general opacity limit.

5.2 GRAQC 391-3-1-.02(2)(C), INCINERATORS

This regulation limits the PM and visible emissions from incinerators. Per the GRAQC, an incinerator is defined as follows:

> *…all devices intended or used for the reduction or destruction of solid, liquid, or gaseous waste by burning.*[68]

Although the proposed No. 3 Biomass Boiler will combust pulp mill sludge, the main purpose of the boiler is not the destruction of solid waste. Boilers and industrial furnaces that burn non-hazardous waste as a fuel are specifically exempted by GRAQC 391-3-1-.02(2)(c)(6)(viii) from Rule (c) applicability. Therefore, Rule (c) will not apply to the proposed No. 3 Biomass Boiler.

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

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

> *…equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or superheating steam, heating air as in warm air furnaces,*

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

[68] GRAQC 391-3-1.01(hh)

furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls.[69]

The main usage of the proposed No. 3 Biomass Boiler will be the generation of steam, thus subjecting the boiler to this regulation. For the No. 3 Biomass Boiler, which will be constructed after January 1, 1972 and will be greater than 250 MMBtu/hr, Rule (d) establishes a PM limit of 0.10 lb/MMBtu and a 20% opacity limit (except one 6-minute period per hour of up to 27%).[70]

Rule (d) also establishes NO_X emission limitations for fuel-burning equipment with a heat input capacity equal to or greater than 250 MMBtu/hr. The rule specifically regulates NO_X emissions from the combustion of coal, oil, or natural gas. The rule does not regulate NO_X emissions from the combustion of biomass. While the overall capacity of the proposed No. 3 Biomass Boiler exceeds 250 MMBtu/hr, GPI will restrict operation of the burners such that the maximum heat input capacity of natural gas that can be fired at a given time does not exceed 249 MMBtu/hr.[71] Based on previous Georgia EPD guidance for similar other biomass boilers using fossil fuels as back-up fuels, the Rule (d) NO_X limits are intended to apply only to boilers with fossil fuel heat input capacities of greater than or equal to 250 MMBtu/hr as Rule (d) was patterned off of NSPS Subpart D, which includes a 0.30 lb/MMBtu NO_X limit for fuel oil, fuel oil with biomass, and natural gas with biomass).[72] Accordingly, GPI contends that the Rule (d) NO_X emission limitation of 0.2 lb/MMBtu does not apply to the proposed No. 3 Biomass Boiler.[73]

Requirements for the No. 2 Power Boiler will remain unchanged as a result of the conversion to natural gas firing only.

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

This regulation, commonly known as the process weight rule (PWR), establishes PM limits for all sources if not specified elsewhere. The PM emissions are limited based on the following equations (for equipment constructed or modified after July 2, 1968), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hr, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:[74]

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

[70] GRAQC 391-3-1-.02(2)(d)2(iii), 3

[71] GPI will restrict burner operation such that the total natural gas heat input does not exceed 249 MMBtu/hr during the worst-case operating scenario, which will occur when the three startup burners (total of 135 MMBtu/hr) and one load burner (122 MMBtu/hr) fire simultaneously.

[72] 40 CFR 60.44(a)(2)

[73] GRAQC 391-3-1-.02(2)(d)2(iii), 3, 4(iii)

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

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

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

Since the proposed No. 3 Biomass Boiler will be subject to a PM limit under Rule (d), this rule will only apply to the proposed fly ash silo and handling units, bottom ash handling system, biomass handling units, new sand storage and handling units, sorbent storage and handling units, and proposed cooling tower.

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

This regulation establishes SO_2 emission limits for fuel-burning sources, not "equipment". New fuel burning sources constructed after January 1, 1972, capable of firing fossil fuel at a rate exceeding 250 MMBtu/hr are subject to SO_2 lb/MMBtu emission limitations. As previously detailed, the proposed No. 3 Biomass Boiler will be limited to a maximum heat input rate less than 250 MMBtu/hr when combusting natural gas, the sole fossil fuel to be combusted by the unit. Accordingly, the SO_2 emission limitations of Rule (g) will not apply to the No. 3 Biomass Boiler.[75] As a fossil fuel-burning source with a heat input capacity above 100 MMBtu/hr, however, the proposed No. 3 Biomass Boiler will be limited to 3% sulfur content for any fuel fired.[76]

Requirements for the No. 2 Power Boiler will remain unchanged as a result of the conversion to natural gas firing only.

5.6 GRAQC 391-3-1-.02(2)(N) – FUGITIVE DUST

This regulation requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. The proposed ash silo and handling units, biomass handling units, sand storage and handling units, sorbent storage and handling units, hog tower, and cooling tower will be covered by this generally applicable rule. The Macon Mill will take the appropriate precautions to prevent fugitive dust from becoming airborne and to ensure that the percent opacity is less than 20 percent.

5.7 GRAQC 391-3-1-.02(2)(GG), KRAFT PULP MILLS

This regulation provides for TRS emissions limitations for sources at Kraft pulp mills that were in operation on September 24, 1976, and is similar to NSPS Subpart BB. The No. 3 Biomass Boiler will not be an affected source under this rule.

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

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

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

Rule (uu) requires Georgia EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). Since this project does not qualify as a major modification for visibility-impacting pollutants (NO_X, total PM_{10}, SO_2, and H_2SO_4), no visibility impact modeling will be performed.[77]

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

Rule (jjj) limits NO_X emissions from electric utility steam generating units located in or near the original Atlanta 1-hour ozone nonattainment area. The Macon Mill is not located within the geographic area covered by this rule.

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

Rule (lll) limits NO_X emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. The Macon Mill is not located within the geographic area covered by this rule, and further, the new No. 3 Biomass Boiler's capacity will be greater than 250 MMBtu/hr.

5.11 GRAQC 391-3-1-.02(2)(MMM), NO_X FROM STATIONARY GAS TURBINES

Rule (mmm) limits NO_X emissions from stationary gas turbines with capacities between 100 kW and 25 MW (inclusive) that are located in or near the original Atlanta 1-hour ozone nonattainment area. The Macon Mill is not located within the geographic area covered by this rule, and further, the proposed turbine will be a steam turbine, not a combustion turbine.

5.12 GRAQC 391-3-1-.02(2)(NNN), NO_X FROM LARGE STATIONARY GAS TURBINES

Rule (nnn) limits NO_X emissions from stationary gas turbines with capacities greater than 25 MW that are located in or near the original Atlanta 1-hour ozone nonattainment area. The Macon Mill is

[77] Additionally, based on the October 2010 guidance from the Federal Land Managers' (FLM Air Quality Related Values Work Group (FLAG), FLAG Phase I Report – Revised, October 28, 2010), detailed Air Quality Related Values (AQRV) modeling for visibility and deposition is not required for facilities located more than 50 km from the nearest Class I area and have a Q/d value of less than 10 [where Q is the sum of the short-term, daily maximum NO_X, PM_{10}, and SO_2, and H_2SO_4 project emission increases (expressed in tpy) and d is the distance to the Class I area (expressed in kilometers)]. This Q/d screening threshold was proposed since it is consistent with what was utilized by U.S. EPA in their 2005 Best Available Retrofit Technology (BART) guidelines. Using the project increases, Q equals 559 tpy. The closest Class I area to the Macon Mill is the Okefenokee Fish and Wildlife Refuge, located approximately 227 km from the Macon Mill. Thus, the Q/d value is 2.46, which is well below 10.

not located within the geographic area covered by this rule, and further, the proposed turbine will be a steam turbine, not a combustion turbine.

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

Rule (rrr) specifies requirements for fuel-burning equipment with capacities of less than 100 MMBtu/hr installed before May 1, 1999, or units with capacities less than 10 MMBtu/hr installed after May 1, 1999 located in or near the original Atlanta 1-hour ozone nonattainment area. The Macon Mill is not located within the geographic area covered by this rule, and further, the proposed No. 3 Biomass Boiler's capacity will be greater than 10 MMBtu/hr.

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

Rule (sss) establishes requirements to utilize certain control devices and effective dates for a number of coal-fired Georgia Power sources only; a periodic reevaluation is required by December 31, 2023 to determine if additional controls are needed from electric utility steam generating units. No requirements under this rule will apply to the proposed No. 3 Biomass Boiler at this time.

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

Rule (ttt) limits mercury emissions from coal-fired boilers installed on or after January 1, 2007 that produce electricity for sale and have a capacity of more than 25 MW. As the proposed No. 3 Biomass Boiler will not combust coal, it will not be subject to Rule (ttt).

5.16 GRAQC 391-3-1-.03(1), Construction Permitting

The proposed project will require physical construction activities to allow construction of the new No. 3 Biomass Boiler, ancillary equipment, and removal of the coal and oil combustion capabilities of the existing No. 2 Power Boiler. Emissions increases associated with the proposed project are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i).[78] Further, as discussed in Section 4.2, PSD permitting is required for CO. Therefore, a construction permit application is necessary and is included in Appendix D.

5.17 GRAQC 391-3-1-.03(10), Title V Operating Permits

The Mill is a major source since the potential emissions of regulated pollutants exceed the thresholds established by Georgia's Title V Operating Permit Program. The Mill operates under its renewal Title V permit, Permit No. 2631-021-0001-V-03-0, effective March 10, 2008. Modifications to existing permit conditions will be required as part of the proposed project as well as addition of new

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[78] Based on Georgia EPD guidance, usage of the *de minimis* permitting exemption thresholds must consider actual-to-potential emissions increases, not actual-to-projected actual emissions increases.

conditions to allow the project to avoid NSR permitting for certain pollutants and to establish appropriate BACT limits for pollutants undergoing NSR permitting. Therefore, the proposed project constitutes a Title V major modification, and GPI has included the Title V operating permit application database and proposed permit conditions in Appendix E.

5.18 INCORPORATION OF FEDERAL REGULATIONS BY REFERENCE

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

- GRAQC 391-3-1-.02(7) – PSD
- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-02(11) – CAM
- GRAQC 391-3-1-.02(12)-(13) – CAIR
- GRAQC 391-3-1-.13 – ARP

6. BACT ASSESSMENT

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

6.1 BACT DEFINITION

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

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

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

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

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

6.1.1 EMISSION LIMITATION

an emissions limitation

First and foremost, BACT is an emission limit. While BACT is prefaced upon the application of technologies to achieve that limit, the final result of BACT is a limit. In general, this limit would be an emission rate limit of a pollutant (i.e., lb/MMBtu).[79]

6.1.2 CASE-BY-CASE BASIS

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

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

> *The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]… The BACT analysis, therefore, involves judgment and balancing.*[80]

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[81] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

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

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

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

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

Step 1. Identify all possible control technologies;

Step 2. Eliminate technically infeasible options;

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

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

Step 5. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, [82] this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 6.1.1, the BACT limit is an emissions limitation and does not require the installation of any specific control device.

6.1.3 ACHIEVABLE

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

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

As discussed by the DC Circuit Court of Appeals,

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[83]

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

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the*

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[82] In November 2010, the U.S. EPA issued a guidance document for the permitting of GHGs that recommends that permitting authorities use the same top-down BACT process to determine BACT for GHGs. U.S. EPA Office of Air and Radiation, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases, November 2010,*page 18, http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf,

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

> *lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.* [84]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the emission unit must be in compliance with that limit for the lifetime of the unit on a continuous basis. Thus, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[85]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 6.2).

6.1.4 FLOOR

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

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

6.2 REDEFINING THE SOURCE

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

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

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

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

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[86]
>
> …
>
> *When the Administrator first developed* [U.S. EPA's policy against redefining the source] *in* Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit."*[87]

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

> *For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.*[88]

U.S. EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[89]

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

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

[88] U.S. EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30.

[89] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007, 499 F.3d 653 (7th Cir. 2007).

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

GPI defines the proposed source as a combined heat and power system with a 620 MMBtu/hr biomass boiler using bubbling fluidized bed combustion technology providing steam to a 40 MW steam turbine generator. While circulating fluidized bed (CFB) boilers are also sometimes used for biomass combustion, they are primarily used for either coal combustion or when a wide mix of fuel types are intended. Given the difference in design of a CFB, the additional circulating loop in the boiler results in additional station load, reducing the overall project efficiency. A CFB and a BFB provide essentially equivalent combustion, but the CFB requires additional equipment (for the circulating loop) with no gain in combustion quality.

In comparison to a stoker boiler, a BFB provides much better combustion, as the HAP emission factor discussion in Section 3.4 and Appendix B document. While a stoker can achieve generally similar controlled emissions of PSD-regulated pollutants, it cannot achieve the same low emissions of HAP. In addition, a stoker boiler provides less flexibility to adapt to normal variations in the biomass composition.

6.3 BACT REQUIREMENT

The BACT requirement applies to each new or modified emission unit from which there are emissions increases of pollutants subject to PSD review. The proposed project is subject to PSD permitting for CO, and thus, subject to BACT for this pollutant. The No. 3 Biomass Boiler and ancillary equipment are subject to BACT for each pollutant requiring PSD permitting that is emitted by the particular piece of equipment. The proposed No. 3 Biomass Boiler is the only new emissions unit associated with the proposed project that is a source of CO; project ancillary sources are not expected to emit CO.

Emission increases of CO have been conservatively predicted for the No. 2 Power Boiler as part of the emissions analysis detailed in Section 3 of this report. However, GPI maintains that the No. 2 Power Boiler is not a modified emissions unit as traditionally defined per the PSD program requirements, but is instead an associated emission unit. As a result of the proposed project, the No. 2 Power Boiler simply will retain the ability to combust natural gas, but will no longer combust coal or fuel oil. GPI is able to remove the prior fuel flexibility needed for the No. 2 Power Boiler as a result of using a more economical and renewable fuel, biomass, on the new No. 3 Biomass Boiler.
U.S. EPA has set a clear precedent that associated emission units are not subject to BACT review as part of the NSR permitting process.

Therefore, the BACT analysis only considers the No. 3 Biomass Boiler.

6.4 BACT ASSESSMENT METHODOLOGY

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed project. As previously noted, the minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable

NSPS or NESHAP emission rate for the source. No NSPS or NESHAP currently establish CO emission limits for the No. 3 Biomass Boiler. Upon promulgation of the final Boiler MACT, GPI anticipates that a CO limit will be established under that rule as a surrogate limit for organic HAP.

Note that on June 4, 2010, U.S. EPA proposed a Boiler MACT standard including a CO limit of 40 ppm 3% O_2 on a 30-day averaging period for new fluidized bed biomass boilers; the proposed limit would apply during all operating periods.[90] Numerous industry groups, including boiler manufacturers, GPI, and other pulp and paper companies in Georgia and throughout the U.S. submitted comments to U.S. EPA discussing the infeasibility of achieving such a limit and urging U.S. EPA to establish a limit that could be achieved in practice.[91] Appendix C contains extracts of relevant concerns addressing the CO limit from selected comment letters; these concerns can be summarized as follows:

- ▲ Major respected fluidized bed biomass boiler vendors are unable or unwilling to offer emission guarantees for the proposed limits based on economically feasible, commercially available technology, especially for CO limits for biomass units.
- ▲ The proposed limits did not properly account for the emissions variability during startup and low load operations. Rather limits were established based on stack testing during normal operations rather than usage of long-term CEMS data that encompasses startup, shutdown, and malfunction event emissions. Therefore, the proposed limits cannot reasonably be met during all periods of boiler operation.
- ▲ Biomass variability (type, origin, time of year harvested, moisture content, rainfall on outdoor storage piles) makes is difficult to predict and control CO emissions. U.S. EPA did not account for such variability in establishment of the CO limit. Higher moisture contents such as those found in bark result in higher CO emissions than dry biomass since the moisture causes less even combustion. Most fuels combusted in pulp and paper industry boilers are wet fuels.
- ▲ The CO limit for new fluidized bed biomass boilers was established based on an emission unit firing a blend of dry biomass, sludge, and almost twenty percent natural gas, which would have lower CO emissions than 100% wet biomass or a wet biomass/sludge blend. Therefore, this limit is too low for units not combusting a similar fuel mix containing dry biomass and natural gas.
- ▲ Low CO emissions will result in increased NO_X emissions as well as decreased boiler efficiency and increased fuel usage to offset the increased excess air. As the GPI Macon Mill is located in an area previously classified as nonattainment for ozone, it is desirable to minimize NO_X emissions. Additionally, increased fuel usage would result in increased

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[90] *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (proposed Boiler MACT), as published in the Federal Register on June 4, 2010 (Volume 75, No. 107, pages 32006 – 32073).

[91] Refer to Docket EPA-HQ-OAR-2002-0058, http://www.regulations.gov/#!docketDetail;dct=FR+PR+N+O+SR;rpp=10;so=DESC;sb=postedDate;po=0;D=EPA-HQ-OAR-2002-0058

overall boiler mass emissions, including GHG, since the total steam demand would not decrease.

- ▲ Transient conditions can occur during normal operations for boilers that are not base-loaded, and the fluctuations in load (i.e., when a paper machine goes down or suddenly starts up) can result in unstable operating conditions, making control of CO difficult. U.S. EPA did not account for such conditions in establishment of the CO limit.
- ▲ Emission limits were developed based on an emissions database that contained numerous errors identified by the respective facilities and/or industry groups that when corrected are expected to noticeably change the proposed emission limits. Such errors include assigning boilers to the wrong subcategories (both for fuels and combustion types), including duplicate test results, relying on test results obtained using test methods other than those specified by the proposed rule, inconsistent treatment of detection limits (including setting non-detects to zero for individual test runs), not combining individual stack results for units with multiple stacks (i.e., not summing the total emissions before converting to a lb/MMBtu basis), exclusion of test results for best performing units from testing situations developed to mimic upset conditions, and inclusion of data that did not meet QAQC standards.

Recognizing the challenges associated with the proposed rule after initial review of stakeholder comments submitted, on December 7, 2010, U.S. EPA requested a delay in the court-mandated schedule for issuance of the final Boiler MACT rule and an opportunity to re-propose the rule itself.[92] In their January 3, 2011 reply memorandum, U.S. EPA states:[93]

> *Based on its review to date of the over 4,800 individual comments received in response to the proposed emission standards under section 112(c)(6), EPA's preliminary assessment is that the comments may materially affect important decisions relating to the level of the emission standards at issue. Specifically, as EPA explained, the comments raise a number of complex and significant issues, several of which could not have been previously anticipated. These issues relate, for example, to source categorizations and the appropriate scope of coverage of the final emission standards. As a result of these significant issues, the Office of Air and Radiation has recommended to the Administrator certain changes to the major source boilers, area source boilers and CISWI rules and has further recommended that the rules be re-proposed because the recommended changes would change the direction from the proposals sufficiently to make additional notice and comment advisable.*
> …
> *Promulgating a flawed rule does nothing, however, to advance the goals of Congress. Such an action can ultimately delay implementation of effective standards. As indicated in the Supplemental Declaration of Mr. Tsirigotis, the Office of Air and Radiation has recommended to the Administrator certain changes to the rules "that could significantly change the direction from*

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[92] *EPA's Memorandum in Support of Motion to Amend Order of March 31, 2006.* Sierra Club v. Jackson, U.S. District Court for the District of Columbia, Case No. 1:01CV01537. Document 136-1, filed December 7, 2010.

[93] *EPA's Reply Memorandum in Support of Motion to Amend Order of March 31, 2006.* Sierra Club v. Jackson, U.S. District Court for the District of Columbia, Case No. 1:01CV01537. Document 144, filed January 3, 2011.

the proposals," Supp. Decl. ¶ 26, and this recommendation makes clear that EPA is seeking to avoid issuing flawed rules.

…

Many comments contained new emissions data; critiques of EPA's existing data and analytical approaches; and objections to EPA's method of categorizing sources. Id. ¶¶ 19, 21-22. Such input goes to the basic underpinnings of EPA's calculations of emission standards, which are premised on mathematical calculations based on data gathered from existing sources.

For the reasons summarized and as detailed further in the Appendix C comments provided by boiler vendors, industry trade groups, and pulp and paper facilities and in light of U.S. EPA's acknowledgement of flaws in the original proposed rule, U.S. EPA significantly modified the original proposal for new biomass BFB units and promulgated an emission limit of 260 ppm 3% O_2.[94] However, as previously detailed, the effective date of these standards has been stayed. Accordingly, U.S. EPA clearly no longer believes the proposed 40 ppm at 3% O_2 on a 30-day rolling average is demonstrated as achievable; therefore, it is not considered further in this BACT evaluation.

6.4.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNOLOGIES

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

Trinity performed searches of the RBLC database in December 2010 and January 2011 to start identifying the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed biomass boiler. The following categories were searched:

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

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[94] *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Boiler MACT), Table 1 – *Emission Limits for New or Reconstructed Boilers and Process Heaters*, as published in the Federal Register on March 21, 2011 (Volume 76, No. 54, pages 15687 – 15689).

- ▲ Miscellaneous Boilers, Furnaces, and Process Heaters (RBLC Code 19.600)

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

As noted previously, no other units are subject to BACT review. Therefore, no additional RBLC searches or other technical reviews were performed.

6.4.2 ECONOMIC FEASIBILITY CALCULATION PROCESS

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

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[95]

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

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

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

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

where i is the annual interest rate and n is the equipment life in years. The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For this analysis, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.[96]

Note that all economic calculations are based on 2010 dollars. Detailed cost analyses calculations are presented in Appendix C.

6.5 NO. 3 BIOMASS BOILER - CO BACT

6.5.1 BACKGROUND ON POLLUTANT FORMATION

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

6.5.2 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

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

- Oxidation Catalyst
- Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

6.5.2.1 OXIDATION CATALYST

A catalytic oxidation system is designed such that the combustion gas passes over a catalyst bed (usually a noble metal such as palladium or platinum) where CO is converted into carbon dioxide (CO_2). This process requires temperatures above 500°F to achieve conversion of CO.[97] To prevent fouling of the catalyst, catalytic oxidation units are typically installed downstream of the particulate control device, requiring significant auxiliary fuel input (such as natural gas) to raise the temperature of the flue gas to the required operational temperature.

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

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

6.5.2.2 GOOD DESIGN AND OPERATING PRACTICES

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

6.5.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

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

6.5.4 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 6-1.

TABLE 6-1. REMAINING CO CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	Oxidation Catalyst	0.075 lb/MMBtu
2	Good Design and Operating Practices	0.15 lb/MMBtu

6.5.5 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

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

6.5.5.1 OXIDATION CATALYST

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas. A stand-alone oxidation catalyst system would be expected to reduce CO emissions from the proposed biomass boiler to 0.075 lb/MMBtu.[98]

[98] This is the lowest value seen in the RBLC for units using oxidation catalysts (refer to Table 6-2). Further, this limit is for baseload utility boilers, not for an industrial boiler such as the No. 3 Biomass Boiler that would experience variability in fuels and loads and thus, higher CO emissions.

GPI evaluated the environmental, energy, and economic impacts related to operation of an oxidation catalyst system. Environmental and energy impacts stem from the use of auxiliary fuel to reheat the flue gas stream. Preliminary estimates indicate an additional 73,900 scf/hr of natural gas combustion would be required to provide reheating to a minimum catalytic oxidation requirement of 500°F.

Next, GPI evaluated the economic impact of an oxidation catalyst system. Based on estimated total capital costs and OAQPS Manual equations (details provided in Appendix C), the annualized costs for a stand-alone oxidation catalyst system would be expected to be more than $21,000 per ton of CO removed.

GPI has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses. In particular, the annualized cost for the stand-alone oxidation catalyst is well beyond the range of cost effectiveness. In addition, the use of a non-renewable fuel source to achieve emission reductions for a predominately renewable energy generation source presents a negative energy impact. Thus, GPI proceeded with evaluating the next most efficient control option presented in Table 6-1.

6.5.5.2 GOOD DESIGN AND OPERATING PRACTICES

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

6.5.6 SELECTION OF BACT (STEP 5)

Good design and operating practices to achieve minimum emissions of CO is determined as the BACT control for the proposed boiler. The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix C). The most stringent limits are shown in Table 6-2 and were considered by GPI in determining the appropriate emission rates to propose as BACT for the No. 3 Biomass Boiler.

TABLE 6-2. MOST STRINGENT RBLC ENTRIES FOR CO CONTROL

ID	State	Company/Facility	Boiler Type	New or Modified?	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Utility or Industrial?	Note(s)
MA-02a	MA	RUSSELL BIOMASS	BFB	New	740	Clean Wood	12/30/2008	0.075	Unknown	Good Combustion Practices	CEMS	Utility	
MA-02b	MA	RUSSELL BIOMASS	Stoker	New	740	Clean Wood	12/30/2008	0.075	Unknown	Oxidation Catalyst	CEMS	Utility	1
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	New	663	Wood	Application	0.075	Unknown	Oxidation Catalyst	CEMS	Utility	1
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	New	38 MW	Biomass	Application	0.075	Unknown	Oxidation Catalyst	CEMS	Utility	1
NH-0018	NH	BERLIN BIOPOWER	BFB	New	1013	Whole tree wood chips, low grade clean wood,	7/26/2010	0.075	Calendar Day	BFB Boiler Design and FGR	CEMS	Utility	
TX-0555	TX	ASPEN POWER - LUFKIN GENERATING PLANT	Stoker	New	693	Untreated Wood Waste	10/26/2009	0.075	Rolling 30-day	Oxidation Catalyst	CEMS	Utility	
GA-12	GA	OGLETHORPE POWER CORPORTATION	BFB	New	1,399	Woody biomass fuel blend, biodiesel, ULSD	12/22/2010	0.08	30-day average	Good Combustion Practices	CEMS	Utility	
CT-0156	CT	MONTVILLE POWER LLC	Stoker	Modified	600	Clean wood, NG, ULSD	4/6/2010	0.10	8-hour	Oxidation Catalyst	CEMS	Utility	
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	New	436	Biomass, Natural Gas (startup)	Draft 2009	0.10	8-hour	Good Combustion Practices	CEMS	Utility	
FL-0318	FL	HIGHLANDS ETHANOL FACILITY	BFB	New	198	Stillage cake, biomass, NG, ULSD, and biogas	12/10/2009	0.10	30-day rolling	Good Combustion Practices	CEMS	Industrial	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	New	768	Coal, Biomass, Petcoke, TDF	2/18/2009	0.10	30-day	Good Combustion Practices	CEMS	Industrial	
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	New	720	Wood, Coal	10/25/2004	0.10	24-hour	CFB Design	CEMS	Utility	
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	Modified	318	Wood	4/4/2006	0.10	30-day	Oxidation Catalyst	CEMS	Utility	
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	New	483	Biomass	Draft, 2007	0.105	30-day	Good Combustion Practices	CEMS	Utility	2
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	FB Gasification	New	523.1	Biomass, biodiesel	2008	0.105	30-day	Good Combustion Practices	CEMS	Utility	
GA-02	GA	YELLOW PINE ENERGY COMPANY	CFB	New	1450	Biomass, TDF, Propane, Fuel Oil	9/8/2010	0.149	30-day	Good Combustion Practices	CEMS	Utility	3
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BFB	New	400	Biomass, Oil/Grease/Fat, Biodiesel, Chicken Litter	7/29/2008	0.149	30-day	Oxidation Catalyst	CEMS	Utility	3
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BFB	New	1374	Biomass, Gas	3/1/2007	0.15	30-day	Good Combustion Practices	CEMS	Utility	
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB	New	996	Coal, Petcoke, Biomass, TDF	8/16/2006	0.154	24-hour	Good Combustion Practices	CEMS	Industrial	
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	Unknown	New	200	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	0.17	30-day	Good Combustion Practices	CEMS	Industrial	3
MI-0386	MI	RIPLEY HEATING PLANT	CFB	New	205	Wood, Coal, Gas	5/12/2008	0.17	3-hour	Good Combustion Practices	Stack Test	Institutional	

1. Part of an RSCR system (includes an SCR and an oxidation catalyst).
2. Based on lb/hr limit and maximum permitted capacity.
3. Case-by-case MACT limit

As seen from Table 6-2 and Table C-1, CO emission rates for biomass boilers vary based on a few major factors. Primarily, the amount of CO emissions is inversely related to the amount of NO_X emissions. This is due to the basic principles of NO_X and CO formation in combustion. In general, incomplete combustion leads to increased CO formation, while any amount of excess oxygen, which is needed for complete combustion, allows for the fuel-bound nitrogen to react with the oxygen to form fuel NO_X.

Additionally, CO formation will vary with the changes in boiler load and operating nature (i.e., baseload or swing loads). Baseload boilers (i.e., those at electrical generation facilities) operate at a consistent load and generally have a more uniform fuel mix than swing boilers which must continuously adjust their load with the steam demands of the industrial facility and generally have a less uniform fuel mix. With constant changes to the load and fuel mix, it is more difficult to adjust boiler operations to minimize CO formation as the fuel/air ratios are consistently changing. Therefore, with the steam demand changes and associated load swings, CO formation in a swing boiler is higher than that in a comparable baseload boiler. GPI's proposed No. 3 Biomass Boiler will operate in a swing fashion, adjusting steam production with the facility's steam demand, and it will also combust a mixture of biomass and mill sludge, resulting in a variable fuel mix.

In reviewing Table 6-2, a number of the most stringent limits are for boilers employing oxidation catalysts (often part of a system that is combined with a selective catalytic reduction system which is providing reheating of the exhaust stream). Such BACT determinations were not considered further by GPI as an oxidation catalyst was determined to be economically infeasible for this proposed project. Of the remaining most stringent limits, most of these are for boilers operating at a power generation utility facility and would be expected to operate in a baseload fashion, enabling them to achieve lower CO emissions than an industrial boiler operating with swing loads. The following units from Table 6-2 are utility units and are generally not comparable to the proposed GPI boiler in light of the swing loading requirement:

- ▲ Russell Biomass – BFB utility boiler with a 0.075 lb/MMBtu limit combusting clean wood (primarily whole trees with some municipal wood, stump grindings, and pallet grindings). Prior to being combusted in the boiler, the wood will be kept in covered storage for at least 3 days and mixed to ensure a consistent fuel mix is fed to the boiler. It appears the limit is applied based on a stack test (normal operations) and on a 12-consecutive month basis using the CEMS.
- ▲ Berlin Biopower – BFB utility boiler with a 0.075 lb/MMBtu calendar day limit combusting whole tree wood chips and low grade clean wood (chipped to a uniform size). The permit limits the boiler to operating at 70% load or higher except during startup and shutdown operations. The permit requires the permittee to submit data within 1 year of operations to establish the appropriate CO limit for startup and shutdown operations. Initially, startup and shutdown emissions are only included in the tpy BACT emission limit.

- Oglethorpe Power Corporation Warren Boiler – BFB utility boiler (baseload) whose 0.08 lb/MMBtu, 30-day averaging period, limit excludes periods of startup and shutdown.
- Watertown Renewable Power – FB gasification utility boiler meeting a 0.10 lb/MMBtu, 8-hr average period limit. Startup, shutdown, and malfunction events are limited to 3 hours in duration, and emissions from transient conditions are tracked separately with the option to establish separate permit limits that would apply during transient conditions.
- Schiller Station, Public Service of NH – CFB utility boiler with a 0.10 lb/MMBtu limit with a 24-hour averaging period combusting wood and coal. The limit applies regardless of fuel and only for periods of 50% load or greater.
- Western Water & Power Estancia Basin Biomass – BFB utility boiler with a 0.105 lb/MMBtu 30-day rolling average limit (limit is actually a lb/hr limit). Boiler combusts wood and up to 30% agricultural wastes. Stack testing is listed to demonstrate compliance with the lb/hr limit.
- Plainfield Renewable Energy – FB gasification utility boiler with a 0.105 lb/MMBtu 30-day rolling average limit, combusting biomass and clean and recycled wood. This limit excludes transient conditions (permit requires submittal of revised limits for transient conditions upon commencement of operation).
- Yellow Pine Energy Company – CFB utility boiler with a 0.149 lb/MMBtu 30-day rolling average limit that encompasses all periods of operation. Boiler permitted to combust biomass, TDF, propane, and fuel oil.
- Nacogdoches Power Plant – BFB utility boiler with a 0.15 lb/MMBtu 30-day rolling average limit that excludes periods of startup, shutdown, and malfunction.
- Northern Michigan University's Ripley Heating Plant – CFB institutional boiler with a 0.17 lb/MMBtu 3-hour average limit based on stack testing rather than continuous monitoring via a CEMS. Stack testing is conducted at normal operations; therefore, the limit inherently excludes periods of startup, shutdown, and malfunction. [Note that although this unit is located at an institution rather than a utility, it would be expected to operate in a baseload fashion as it serves as a "utility" for the university.]

In review of the industrial units in Table 6-2, GPI noted the following:

- Highlands Ethanol Facility – BFB industrial boiler with a 0.10 lb/MMBtu 30-day rolling average limit. The primary fuel is stillage cake from the ethanol process (75%), supplemented with WWTP biogas (18%) and limited amounts of supplemental biomass (6%) and natural gas for startup (1%).
- Archer Daniels Midland, Columbus – CFB industrial boiler whose permitted fuel is coal and up to 20% biomass/TDF/petcoke and whose 0.10 lb/MMBtu 30-day rolling average limit excludes periods of startup and shutdown.
- Roquette America, Inc. – CFB industrial boiler at a corn milling facility whose permitted fuels include coal, petcoke, biomass, and TDF and has a permit limit of 0.154 lb/MMBtu 24-hour averaging period. The permit describes the biomass combusted as "switchgrass, sugar cane, constalks, etc.", waste timber, and waste paper. Combusts predominately coal and petcoke with little actual biomass.
- Tate & Lyle Ingredients Americas, Inc. – industrial boiler of unknown type whose permitted fuels include corn fibers, natural gas, biogas, and process gas with an emission limit of 0.17 lb/MMBtu on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.

The Highlands Ethanol facility combusts a fuel mixture that differs from GPI's proposed fuel mixture. It is unclear how CO emissions from stillage cake (a byproduct of the ethanol process and the predominant fuel) at the Highlands Ethanol Facility would compare to those from GPI's proposed boiler. The other units identified also combust a substantially different fuel mixture which can make direct comparison of the BACT limits challenging.

GPI is proposing that a limit of 0.15 lb/MMBtu on a 30-day average for CO (as measured by a CEMS) is BACT for the proposed BFB No. 3 Biomass Boiler. This limit is amongst the limits shown in Table 6-2 for industrial boilers; it will be achieved without an oxidation catalyst, and will account for the proposed boiler's load and fuel variability. The BACT limit proposed for CO is for normal operation (i.e., not including startup, shutdown, or malfunction).

6.6 SUMMARY OF PROPOSED PRIMARY BACT LIMITS

Table 6-3 presents a summary of the proposed primary BACT determinations and limits for the proposed No. 3 Biomass Boiler.

TABLE 6-3. PROPOSED PRIMARY BACT DETERMINATIONS FOR NO. 3 BIOMASS BOILER

Pollutant	Limit	Units	Averaging Period	Control Technology
CO	0.15	Lb/MMBtu, CO	30-day	Good Design and Operating Practices

The proposed CO BACT limit would apply during normal operations only. A secondary BACT limit for CO to encompass periods of startup and shutdown events is discussed in Section 6.7.

As noted previously, the project ancillary equipment are not sources of CO and were therefore not subject to a BACT evaluation.

6.7 PROPOSED SECONDARY BACT LIMITS

The primary CO BACT emission limit discussed previously is a rate-based limit based on the boiler heat input (lb/MMBtu), which means that for every unit of heat consumed by the boiler, there will be no more than "X" amount of emissions. These limits reflect what are expected to be the achievable emission rates during periods of normal boiler operation. However, emission limits that directly correspond to the instantaneous heat input of the boiler may not be appropriate during periods of startup and shutdown. In these situations, the amount of fuel, and thus heat input, is lower than during typical operation, which therefore linearly decreases the emission limits. To keep in compliance with the lb/MMBtu limits during times of startup or shutdown, the boiler would have to sustain the expected combustion efficiency of normal operation, where the boiler is designed to operate, at much lower temperatures and flow rates. The non-steady state scenario makes it difficult, if not impossible for the boiler to comply with stringent BACT limits that are based on a heat input rate during startup and shutdown periods.

In the definition of BACT, it clearly states that a BACT limit is one that, "on a case-by-case basis is determined to be achievable."[99] Therefore, in order for GPI to propose limits that are both "achievable" and keep the boiler under a high degree of control during normal operation, GPI is proposing a secondary CO BACT limit to address periods of startup and shutdown. Permitting of separate secondary limits is consistent with what has been proposed and accepted by other power generating facilities. Prairie State Generating Company (Peabody), outside of Marissa, IL, was permitted using secondary BACT limits. This permit, issued April 24, 2005 by the Illinois Environmental Protection Agency (IEPA), was petitioned and taken to the U.S. EPA Environmental

[99] 40 CFR 52.21(b)(12)

Appeals Board (EAB) for review.[100] The EAB sided with the IEPA's issuing of the "secondary" BACT limits, stating that:

> *… adoption of an alternative method during these periods [startup and shutdown] "reflects Illinois EPA's experience with industrial boilers, which found that the rate-based compliance methodology of the NSPS[101] is problematic when applied to stringent BACT limits."… IEPA stated further that, "[w]ithout this provision for an alternative compliance methodology, the BACT limits for SO_2 and NO_X could not be extended with the necessary confidence that compliance is reasonably achievable with the BACT limits."*[102]

Although this statement just refers to SO_2 and NO_X limits, the EAB concurred with IEPA's ruling on lb/hr startup/shutdown BACT limits for CO.[103] Georgia EPD has concurred with this logic based on the issued permit for the Warren County Biomass Energy Facility, with a similar bubbling fluidized bed biomass boiler.[104]

It is GPI's determination that not only is a secondary CO BACT limit justified, but that it is required to ensure with a necessary degree of confidence that the stringent primary BACT limit proposed is achievable given the continuous compliance demonstration method proposed. GPI is proposing a secondary CO limit that is mass-based on an annual (tpy) basis, with compliance determined via CEMS. GPI anticipates that short-term mass emissions during periods of startup and shutdown would not exceed those allowed during normal operating modes.[105] While GPI anticipates lb/MMBtu emissions would exceed the primary BACT limit during startup and shutdown periods, the heat input to the boiler would be much lower than normal operating periods. Given the swing nature of this boiler and the need for flexibility at a manufacturing facility of this type, GPI is not able to reasonably predict the number of startup and shutdown events in a given year, nor the time necessary to complete such activities. Accordingly, GPI is proposing a secondary BACT limit of 407.3 tpy, equivalent to the maximum mass hourly emission rate allowed by the primary BACT limit, presuming 8,760 hours of operation a year. The proposed 407.3 tpy secondary limit would apply at all times.

In determining compliance with the primary BACT limit for CO, GPI would exclude any hours from the average where the steam load was less than 50%. Compliance with BACT during these periods would instead be met by the proposed secondary tpy BACT limit.

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

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

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

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

[104] Georgia Air Permit No. 4911-301-0016-P-01-0, effective December 17, 2010.

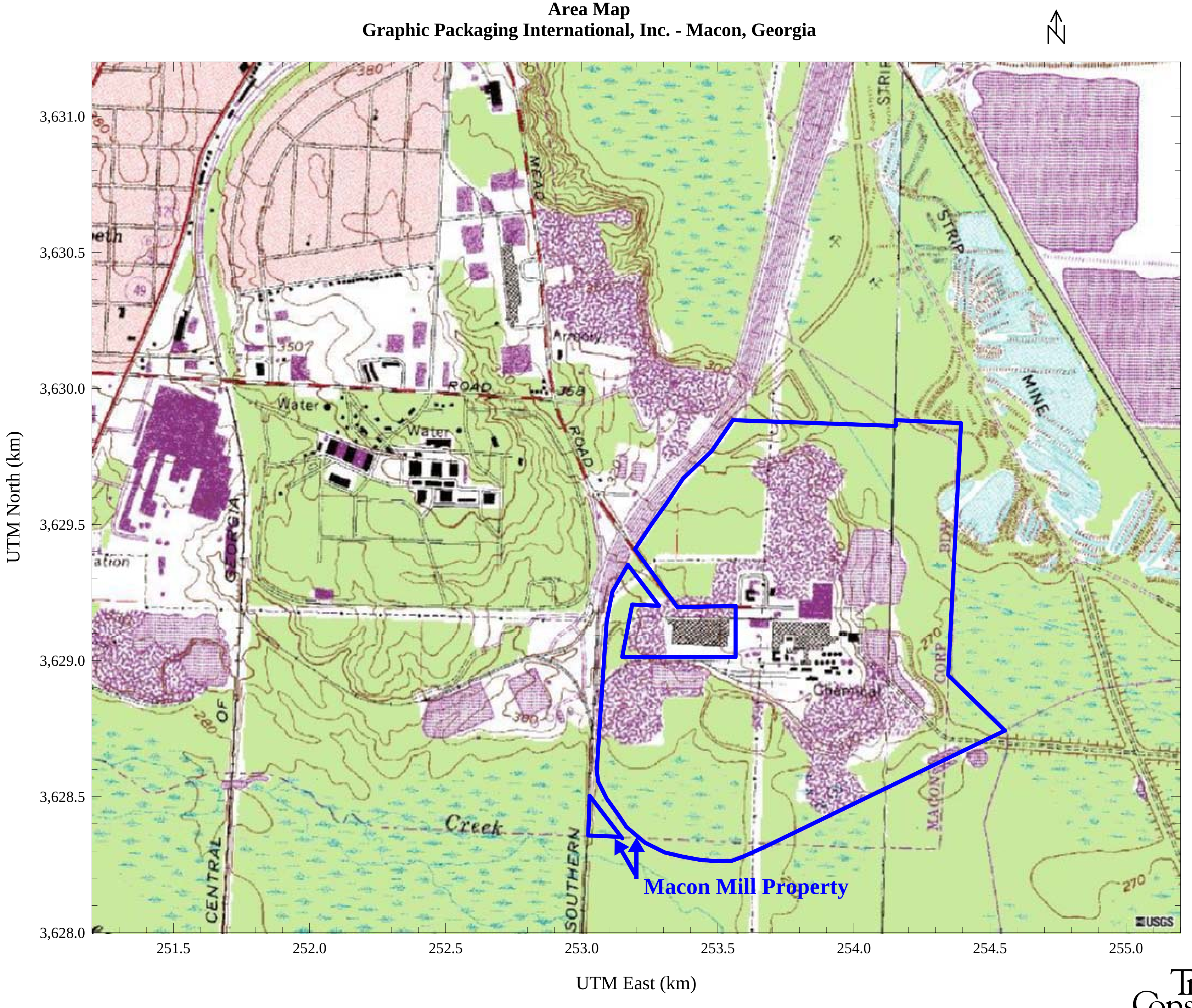
[105] GPI is proposing a 0.15 lb/MMBtu CO primary BACT limit. If operating at maximum load, the equivalent mass emission rate equals 0.15 lb/MMBtu * 620 MMBtu/hr = 93 pounds per hour.

APPENDIX A

FACILITY INFORMATION

Area Map
Site Layout

Area Map
Graphic Packaging International, Inc. - Macon, Georgia



UTM coordinates shown for Zone 17, NAD 83.

Trinity Consultants
Areamap.srf

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Larson Engineering, Inc.
Project Number: 46090902
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REFERENCES & NOTES:
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NO.	DATE	BY	REVISION
C	1/24/2011	HRK	CONVEYOR ROUTING
B	11/19/2010	PAD	FOR ENVIRONMENTAL PERMIT
A	11/10/2010	HRK	ISSUED FOR REVIEW

APPROVED

DRAWN BY: MJT	CHECKED BY:		
DATE: XX/XX/XXXX	JOB NO.:		
SCALE: N/A	ACCOUNT NO.:		

GRAPHIC PACKAGING INTERNATIONAL, INC.
100 Graphic Packaging Int'l Way
Macon, Georgia 31206

RENEWABLE ENERGY PROJECT
OVERALL SITE PLAN

DRAWING NO.
REV. C
M-200

APPENDIX B

EMISSIONS CALCULATIONS

FACTOR DEVELOPMENT FOR BOILER HAP BIOMASS EMISSIONS

Based on AP-42 background data as well as engineering knowledge from boiler manufacturers, fluidized bed combustion (FBC) boilers have more complete combustion than other biomass boiler types and thus, lower organic compound emissions.[106] Emissions data for organic compounds from non-FBC boilers therefore are not expected to be representative of the proposed No. 3 Biomass Boiler organic compound emissions and will likely overestimate such emissions.

In contrast to organic compounds, the variations in boiler combustion technologies are not expected to have much impact on filterable particulate compounds. Rather, the control technology employed will primarily impact the emissions of filterable particulate compounds. ESPs and baghouses (fabric filters) are commonly employed for new biomass boilers and are superior to venturi scrubbers and multiclones. As such, all biomass boilers with ESPs or baghouses would be expected to be representative of the No. 3 Biomass Boiler's particulate emissions (though recognizing that the proposed boiler will have higher particulate removal efficiency than most or all existing units).

GPI initially estimated HAP emissions using emission factors per U.S. EPA's AP-42 Section 1.6, *Wood Residue Combustion in Boilers,* dated September 2003, Tables 1.6-3 and 1.6-4.[107] Review of the potential HAP emissions estimated using conservative AP-42 factors reveals particularly high emissions for several HAP; such emissions are not expected to be appropriate for a new BFB boiler employing a new baghouse since the AP-42 emission factor database is 10 years old and is dominated by stoker boilers and boilers employing multiclones and/or scrubbers. Thus, the proposed No. 3 Biomass Boiler would be expected to have smaller organic and metal HAP emissions.

GPI has reviewed and refined the emission factors for all HAP with potential emissions greater than 1 tpy (based on the conservative AP-42 factors) to be more representative of the proposed No. 3 Biomass Boiler.[108] Specifically, GPI has updated the emission factors for the following pollutants:

- Acetaldehyde
- Acrolein
- Benzene
- Formaldehyde
- Hydrogen Fluoride (note that an AP-42 factor was not included for this pollutant)
- Manganese

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[106] For example, refer to the Babcock & Wilcox BFB technical paper: DeFusco, J.P. et al. *BFB or Stoker – Which is the Right Choice for Your Renewable Energy Project?* May 2007. Available at: http://www.babcock.com/library/pdf/BR-1802.pdf

[107] U.S. EPA, *Wood Residue Combustion in Boilers,* September 2003. Available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf

[108] A refined emission factor for hydrogen chloride, which using the emission factor listed in AP-42 Section 1.6 Table 1.6-3 results in potential emissions greater than 1 tpy, was not developed since GPI is proposing a permit limit. Similarly, a refined factor for chlorine was not considered as no representative boilers were included in the databases evaluated; the default AP-42 factor was utilized. Lastly, the methanol factor was set equivalent to the NCASI factor used for the existing No. 2 Biomass Boiler; methanol emission factor data were not included in the AP-42 or Boiler MACT databases.

- ▲ Styrene
- ▲ Toluene

Note that although GPI only refined the emission factors for HAP with significant emissions, the remaining HAP emissions estimated using AP-42 emission factors are still expected to over-estimate emissions from a FBC boiler employing a baghouse.

The following sections detail the emission factors refinement methodologies.

AP-42 SECTION 1.6 EMISSION FACTORS

U.S. EPA's AP-42 Section 1.6, dated September 2003, includes emission factors for the combustion of wood residue in industrial boilers.[109] Tables 1.6-3 and 1-6.4 include emission factors for a number of speciated organic and metal compounds, respectively. Although Section 1.6 is dated September 2003, the introductory text in this chapter notes that the emission factors were last updated in July 2001.

AP-42 Factor Development Methodology

As part of the background data for AP-42 Section 1.6, U.S. EPA makes available a background report as well as an emission factor spreadsheet containing the test data analyzed during the emission factor development process.[110] The report outlines the sources of the test data as well as how the data were analyzed. The background report specifies the following criteria were used in the development of the emission factors:

- ▲ Incomplete data were deleted and not considered further.
- ▲ Sources determined to be combusting non-representative wood residues were excluded (i.e., sources with large percentage of urban wood).
- ▲ F-factor of 9,240 dscf/MMBtu (from Method 19 of Appendix A of 40 CFR 60) was used to convert data to lb/MMBtu basis if site-specific F-factor was unavailable.
- ▲ Non-detect values were not used in the average factor development when they were greater than detect values.
- ▲ Non-detect values that were less than the cumulative average value were divided in half and used in the average factor development.
- ▲ For test runs with 3 non-detect values that yielded an average that was the maximum of all the data sets considered, the test was excluded.

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[109] U.S. EPA, *Wood Residue Combustion in Boilers,* September 2003. Available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf

[110] Eastern Research Group, *Background Document Report on Revisions to 5th Edition AP-42 Section 1.6 Wood Residue Combustion in Boilers*. July 2001. Report available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/bgdocs/b01s06.pdf Emission factor file available on-line at: http://www.epa.gov/ttn/chief/ap42/ch01/related/c01s06.html

- ▲ In general, separate factors for FBC and non-FBC boilers were not established. Only a separate CO emission factor is provided for FBC boilers.
- ▲ All factors for speciated organic compounds were grouped together, regardless of boiler type, since they were relatively small.

Review of Data Sources

The PROCESS tab of the AP-42 Section 1.6 background data emission workbook lists the individual test reports (not emission factors) evaluated for the AP-42 factor development and assessment. Table 1 lists the breakdown of the boiler types associated with each of these test reports.

TABLE 1. AP-42 SECTION 1.6 TEST REPORTS EVALUATED

Boiler Type	Number of Tests	Percentage of Tests
Stoker	263	59.8%
Dutch Oven	33	7.5%
Gasifier	1	0.2%
FBC	34	7.7%
Not Reported	109	24.8%
Total	440	100%

As Table 1 illustrates, the overwhelming majority of the test reports evaluated for inclusion in the September 2003 version of AP-42 Section 1.6 are from stoker boilers; FBC boilers comprised less than 8% of the test reports evaluated.

Given the dominance of non-FBC boiler test and emission factor data as well as the relatively poor ratings for most of the AP-42 emission factors, one may question whether the AP-42 factors (which lump the data) are representative of the No. 3 Biomass Boiler's anticipated emissions.

OTHER DATA SOURCES REVIEWED

Original Boiler MACT Database[111]

During the development of the original 40 CFR 63 Subpart DDDDD, Boiler MACT, U.S. EPA prepared an emissions database that contains some of the same test data as the AP-42 Section 1.6 database plus additional test data.[112] The database was downloaded, and a query used to create a table containing the relevant emission factor, process, and facility information. The data were then copied into Excel and edited to remove all non-wood or non-biomass test results; results for combination firing of wood or biomass with other fuels (i.e., coal) were also removed. Next, GPI evaluated the specific combustor design for each pollutant test data set and removed all non-fluidized bed boilers.

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[111] Data evaluated are those associated with the Boiler MACT as originally promulgated in 2004. Since that time, the rule was vacated.

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

Note that while the Boiler MACT data set appears to have included many more data than the AP-42 Section 1.6 emissions factor development data set, overlap between the two sets does exist. To identify data that overlapped, GPI looked at the ID numbers themselves between the two data sets as well as comparing the facility/location/tested unit name/similar results. For example, the test set with AP22 as the AP-42 ID and E266 as the Boiler MACT ID were determined to be the same even though the name was not reported in the AP-42 test set; however, the boiler sizes, fuel descriptions, steaming rates (capacity and actual during test run), and location all aligned.[113]

The Boiler MACT data set includes FBC test results from some facilities with multiple tests at the facilities. In considering these facilities, GPI did not exclude any as non-representative of the proposed boiler even though some units may burn fuels such as urban wood waste or agricultural waste (hulls, pits) that may not be a permitted fuel for the No. 3 Biomass Boiler.

2010 Boiler MACT Database[114]

For the development of the revised 40 CFR 63 Subpart DDDDD, Boiler MACT, U.S. EPA prepared an emissions database that contains additional test data to the original Boiler MACT database.[115] The database was downloaded, and a query used to create a table containing the relevant emission factor, process, and facility information. The data were then copied into Excel and edited to remove all non-wood or non-biomass test results; results for combination firing of wood or biomass with other fuels (i.e., coal) were also removed. Next, GPI evaluated the specific combustor design for each pollutant test data set and removed all non-fluidized bed boilers for the evaluation of organic pollutants.[116] For the evaluation of manganese (the only metal pollutant evaluated), GPI considered all boiler types and removed units that did not employ an ESP, a baghouse, or a scrubber.

Maine DEP Acrolein Emission Factor

Concern has been expressed by the Maine Department of Environmental Protection (Maine DEP) to U.S. EPA on the appropriateness of the AP-42 Section 1.6 acrolein factor:[117]

> *…the emission factor for the largest Maine acrolein source category, wood/biomass boilers, is 4.04E-03 lb/MMBtu in AP-42, compared to the Boiler MACT emission factor of 9.47E-06 lb/MMBtu. The consequences of using an emission factor that may be orders of*

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[113] Note that the emission rates between these sources did not perfectly align in the two databases. The AP-42 test values were slightly higher than the Boiler MACT factors, likely due to usage of different heat input factors or other data used to convert ppm or lb/ton factors to a lb/MMBtu basis. AP-42 factors were conservatively used since they were higher in magnitude.

[114] Data evaluated are those associated with the Boiler MACT proposed in 2010; additional data was collected by the U.S. EPA in Fall 2008, to prepare a new version of the original Boiler MACT.

[115] April 2010 database available on-line at: http://www.epa.gov/ttn/atw/boiler/boilerpg.html

[116] Note units without entries or that listed "N/A" were included in GPI's emission factor analysis.

[117] Letter from Mr. David P. Littell (Maine DEP) to Mr. Steve Page (U.S. EPA OAQPS), dated April 19, 2006. Available on-line at: http://maine.gov/dep/air/toxics/SAS_Ltr_to_S_Page.doc

magnitude different than actual emissions include inaccurate risk assessments, poor resource allocation, and improper regulatory oversight.

In a response letter, U.S. EPA does not specifically comment on the acrolein factor but does note:[118]

My office is in the process of revamping the emissions factors program in order to address concerns such as those expressed by your Committee. … as mentioned in the Introduction to AP-42, Volume I, Fifth Edition, the use of emissions factors may not be appropriate in all situations, particularly for emissions limits, standards, source-specific permit limits, and/or in compliance determinations… users should be aware of the limitations in accurately representing a particular facility.

The Maine Air Toxics Inventory (MATI) in fact uses two different acrolein factors for wood combustion emissions. For pulp and paper mill boilers, MATI uses a National Council on Air and Stream Improvements (NCASI) factor of 7.8E-05 lb/MMBtu of wood combustion and a factor of 0.036 lb/ton of wood based on the AP-42 factor and 9 MMBtu/ton wood.[119] The NCASI factor is 50 times smaller than the AP-42 factor of 4.03E-03 lb/MMBtu. To help address these discrepancies, Maine DEP had facilities conduct acrolein testing in 2006 and 2007; these tests yielded emissions ranging from <2.46E-07 to <1.45E-04 lb/MMBtu with an average of <2.98E-05 lb/MMBtu and a median of <9.86E-07 lb/MMBtu.[120]

Maine DEP has recently revised their recommended acrolein factor for biomass combustion in the 2008 annual emissions inventory factor workbook to 7.40E-04 lb/ton of wood based on NCASI guidance.[121] Using the same AP-42 heat input factor of 9 MMBtu/ton of wood, this is equivalent to 8.2E-05 lb/MMBtu, significantly lower than the AP-42 factor. Note that none of the other pollutants listed in the Maine DEP 2008 annual inventory factor workbook utilize NCASI factors.

While the Maine DEP test data and factors can be used to help describe the apparent flaws with the AP-42 emission factor, these data are from boilers of unknown types. As such, the data were not included in GPI's assessments.

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[118] Letter to Mr. David P. Littell (Maine DEP) from Mr. Steve Page (U.S. EPA OAQPS), dated October 2, 2006. Available on-line at: http://maine.gov/dep/air/toxics/mati_docs/EPA-EF-letter-10-12-06.pdf

[119] Refer to the Excel workbook of MATI emissions. Available on-line at: http://maine.gov/dep/air/toxics/MATI_Inventory_Tox_Weight_.001_v3b.zip

[120] Maine Air Toxics Advisory Committee, *Recommended Air Toxics Strategy*, September 17, 2007 Revision. Refer to Table 3 in Appendix I. Available on-line at: http://mainegov-images.informe.org/dep/air/toxics/mati_docs/ATAC_2DEP_2007-06-26_v7.pdf

[121] Maine DEP Default Emission Factors for the Reporting of HAP in the 2008 Annual Emissions Inventory, March 2009. Available on-line at: http://maine.gov/dep/air/emissions/docs/DEP_Default_HAP_EFs%20revised.xls

DEVELOPMENT OF CUSTOM EMISSION FACTORS

Using the AP-42 Section 1.6, original Boiler MACT, and 2010 proposed Boiler MACT background datasets, custom fluidized bed combustion (FBC) boiler organic emission factors were derived based solely on FBC boiler data.

As discussed in the previous sections, FBC boiler data that are likely to be representative of the No. 3 Biomass Boiler were identified for consideration in custom organic HAP emission factors while biomass boilers employing similar PM control device(s) were considered for the custom manganese factor. Care was taken to ensure that overlap between data sets was identified and duplicate entries were not double-counted.

The AP-42 and Boiler MACT FBC boiler test results were combined and sorted via pollutant name. For units with results that were below detection level (BDL), half of the detection level was used for the factor, consistent with U.S. EPA's approach for AP-42. Factors were then averaged to determine a representative factor for the No. 3 Biomass Boiler.

All FBC boiler test factors were used to calculate the average organic pollutant factor as the newer 2010 Boiler MACT database contained very little speciated organic factor data (therefore necessitating usage of the older AP-42 and original Boiler MACT emissions data). However, the acrolein test factor cited as an outlier in Maine DEP memo was excluded as it was more than 1,000 times higher than other FBC boiler test data.[122]

For the manganese factor, only data from the 2010 Boiler MACT database were considered as it included 66 different sets of test data and constitutes newer data than that included in the AP-42 and original Boiler MACT databases.

Table 2 presents a summary of the custom boiler emission factors.

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[122] Memo to Maine DEP MATI Emissions Inventory Subcommittee from Mr. David Dixon, *Dealing with Uncertainty of Acrolein Emissions in MATI Inventory*, dated November 1, 2005. Available on-line at: http://www.dirigo-air.com/news_and_views.htm

TABLE 2. CUSTOM HAP EMISSION FACTORS

Pollutant	Refined Emission Factor (lb/MMBtu)
Acetaldehyde	4.66E-05
Acrolein	9.17E-06
Benzene	2.53E-05
Formaldehyde	2.29E-04
Hydrogen Fluoride	2.22E-04
Manganese	3.61E-04
Styrene	5.60E-07
Toluene	5.72E-06

Appendix B - No. 3 Biomass Boiler Project
Graphic Packaging International, Inc. - Macon, Georgia

Table B-1. Project Potential Emissions (PTE) Summary (Step A)

Pollutant	No. 3 Biomass Boiler PTE (tpy)	Ancillary Equipment PTE Increase (tpy)	No. 2 Power Boiler PTE Increase[1] (tpy)	Total Project Emissions (tpy)	NSR Major Modification Threshold (tpy)	Project PTE Exceed NSR Threshold? (Yes/No)
CO	407.3	-	11.5	418.8	100	**Yes**
NO_X	404.6	-	-118.5	286.1	40	**Yes**
SO_2	869.0	-	-674.5	194.5	40	**Yes**
VOC	27.2	-	3.4	30.5	40	No
Total PM	127.6	11.0	-90.9	47.8	25	**Yes**
Total PM_{10}	133.1	6.9	-71.2	68.7	15	**Yes**
Total $PM_{2.5}$	108.6	5.1	-58.1	55.6	10	**Yes**
Pb	0.1	-	-	0.1	0.6	No
H_2SO_4	13.2	-	-3.2	9.9	7	**Yes**
H_2S	-	-	-	-	10	No
Fluoride[2]	-	-	-	-	3	No
$CO_2e_{\text{non-biogenic}}$[3]	153,021.6	142.1	8,898.1	162,061.9	75,000	**Yes**

1. Represents baseline actual to new potential analysis.
2. Excluding hydrogen fluoride, which is regulated per Clean Air Act Section 112.
3. CO_2e emissions exclude biogenic CO_2 emissions; CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Table B-2. Net Five-Year Contemporaneous Period Projects Emissions Summary (Step B) - CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e

		Emissions (tpy)							
Date	**Project**	**CO**	**NO_X**	**SO_2**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**H_2SO_4**	**$^*CO_2e_{\text{non-biogenic}}$[1]**
2007	Stacker/Reclaimer System Addition	-	-	-	-	-	-	-	-
2010	No. 1 Paper Machine Steam Upgrades[2]	12.1	14.2	14.37	7.45	4.4	4.1	0.2	**
2011	North Biomass Feed System Restoration	-	-	-	6.4	3.8	3.8	-	-
2011/2012	No. 1 Power Boiler Shutdown	-9.2	-262.1	-668.8	-75.5	-62.5	-53.9	-3.2	-93,412.4
2011/2012	Proposed Project (No. 3 Biomass Boiler)	418.8	286.1	194.5	47.8	68.7	55.6	9.9	162,061.9
Total Contemporaneous Period Emissions (tpy)		421.7	38.3	-459.9	-13.9	14.5	9.6	6.9	68,649.5
PSD/NNSR Major Modification Threshold (tpy)		100	40	40	25	15	10	7	75,000
PSD/NNSR Permitting Required?		**Yes**	No	No	No	No	No	No	No

* NSR permitting for greenhouse gases (i.e., CO_2e) is required if the total contemporaneous period emissions exceed the CO_2e major modification threshold AND if NSR permitting is triggered for any other pollutant and the permit application is submitted after January 2, 2011 but before July 1, 2011.
** Some CO_2e emissions may have occurred from the No. 1 Paper Machine steam upgrades project that were not required to be quantified.
1. CO_2e emissions exclude biogenic CO_2 emissions; CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.
2. Refer to application submitted to Georgia EPD on September 14, 2010, for detailed calculations.

Table B-3. No. 3 Biomass Boiler Potential Emissions

Rated Capacity, Total	620.00	MMBtu/hr
Rated Capacity, Natural Gas	249.00	MMBtu/hr
Potential Operation	8,760	hr/yr

Pollutant	Worst-Case Emission Factor (lb/MMBtu)	Worst-Case Emission Factor Basis	Worst-Case Potential Emissions (lb/hr)	Worst-Case Potential Emissions (tpy)
CO	0.15	BACT limit	93.00	407.34
NO_X	0.149	NSR avoidance limit	92.38	404.62
SO_2	0.32	Presumes emissions are less than the NSPS Subpart Db SO_2 emissions threshold which requires an SO_2 limitation; supported by vendor information[1]	198.40	868.99
VOC	0.01	Vendor guarantee[1]	6.20	27.16
PM filterable	0.030	NSPS Subpart Db limit	18.60	81.47
CPM	0.017	AP-42 Section 1.6, Table 1.6-1	10.54	46.17
Total PM	0.047	Sum of PM filterable limit and CPM	29.14	127.63
Total PM_{10}	0.049	NSR avoidance limit	30.38	133.06
Total $PM_{2.5}$	0.040	NSR avoidance limit	24.80	108.62
Pb	4.80E-05	AP-42 Section 1.6, Table 1.6-4	0.03	0.13
H_2SO_4	4.85E-03	NSR avoidance limit	3.01	13.17
H_2S	-	N/A - not anticipated	-	-
Fluoride (non-HF)	-	N/A - not anticipated	-	-
CO_2e non-biogenic[2]	See Table B-3a; converted to CO_2e per 40 CFR 98 Table A-1[3]		34,936.45	153,021.65

1. Emissions guarantee provided by the boiler vendor (Andritz).
2. CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.
3. Global warming potentials (GWP) per 40 CFR 98 Table A-1 are as follows: 1 CO_2 = 1 CO_2e; 21 CH_4 = 1 CO_2e; 310 N_2O = 1 CO_2e.

Table B-3a. No. 3 Biomass Boiler Potential GHG Emissions

Pollutant	Emission Factor (lb/MMBtu)		Potential Emissions (lb/hr)[3]			Potential Emissions (tpy)[3,4]		
	Wood[1]	Gas[2]	Wood	Gas	Maximum	Wood	Gas	Maximum
CO_2	-	116.89	-	29,105.35	29,105.35	-	127,481.43	127,481.43
CH_4	5.00E-03	2.20E-03	3.10	0.55	3.10	13.58	2.40	13.58
N_2O	3.00E-02	2.20E-04	18.60	0.05	18.60	81.47	0.24	81.47
$CO_2e_{\text{non-biogenic}}$[1]					**34,936.45**			**153,021.65**

1. Emission factors provided by boiler vendor. CO_2 emissions from biogenic sources are not considered per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.
2. Emission factors per 40 CFR 98 Tables C-1 and C-2.
3. Potential emissions from each fuel are based on the fuel-specific emission factor and the fuel's maximum heat input capacity to the boiler.
4. Potential annual emissions are based on 8,760 hours of operation per year.
5. CO_2e emissions calculated based on global warming potentials (GWP) per 40 CFR 98 Table A-1 as follows: 1 CO_2 = 1 CO_2e; 21 CH_4 = 1 CO_2e; 310 N_2O = 1 CO_2e.

Table B-4. Power Boilers Heat Input Capacities and Maximum Fuel Usage

Unit	Boiler Rating[1] (MMBtu/hr)	Natural Gas[2] (MMscf/hr)	Fuel Oil[3] (Mgal/hr)	Coal[4] (ton/hr)
No. 1 Power Boiler	198	0.19	1.40	7.80
No. 2 Power Boiler	198	0.19	1.40	7.80

1. Boiler rating is the maximum heat input demonstrated by the power boilers during stack test in 2005, 2007, and 2009, averaged for the three test runs, or the rated capacity, whichever is lowest.
2. Based on GPI actual usage of natural gas per Consolidated Emissions Reporting Rule (CERR) heat content data (1,024 Btu/scf).
3. Based on GPI actual usage of fuel like No. 2 fuel oil per CERR heat content data (141 MMBtu/Mgal).
4. Based on GPI actual usage of coal per CERR heat content data (25.4 MMBtu/ton).

Table B-5. Criteria Pollutant Fuel Emission Factors

Pollutant	Natural Gas[1] (lb/MMscf)	Fuel Oil[2] (lb/Mgal)	Coal[3] (lb/ton)
CO	24	5.00	0.50
NO_X	170	32.00	15.00
SO_2	0.6	See Table B-5b	See Table B-5b
VOC	5.5	0.28	0.06
Filterable PM	1.9	2.00	See Table B-5b
Filterable PM_{10}	1.9	1.00	See Table B-5b
Filterable $PM_{2.5}$	1.9	0.25	See Table B-5b
CPM	5.7	1.50	See Table B-5b
Total PM	7.6	3.50	See Table B-5b
Total PM_{10}	7.6	2.50	See Table B-5b
Total $PM_{2.5}$	7.6	1.75	See Table B-5b
Pb	5.00E-04	1.51E-04	4.20E-04
H_2SO_4	-	See Table B-5b	See Table B-5b
Fluoride (non-HF)	-	3.73E-03	-
CO_2e[4]	119,812	23,422	5,084

1. Natural gas emission factors per AP-42 Section 1.4, Table 1.4-1 for tangential fired, uncontrolled boiler, and Table 1.4-2, July 1998.
2. Fuel oil emission factors per AP-42 Section 1.3 Tables 1.3-1 and 1.3-3 for No. 6 fuel oil, tangentially fired boiler and Table 1.3-6.
3. Coal emission factors per AP-42 Section 1.1 Tables 1.1-3, 1.1-5, and 1.1-19 for PC, dry bottom, tangentially fired boilers and Table 1.1-6.
4. Greenhouse gas emission factors per 40 CFR 98 Tables A-1, C-1, and C-2.

Table B-5a. Nos. 1 and 2 Power Boilers (B001, B002) - Past Actual Particulate Matter Emission Factors

Pollutant	Natural Gas[1] (lb/MMscf)	Fuel Oil[2] (lb/Mgal)
Filterable PM	0.19	0.20
Filterable PM_{10}	0.19	0.10
Filterable $PM_{2.5}$	0.19	0.025
CPM	0.57	0.15
Total PM	0.76	0.35
Total PM_{10}	0.76	0.25
Total $PM_{2.5}$	0.76	0.18

1. Natural gas emission factors per AP-42 Section 1.4, Table 1.4-2, July 1998, with 90% scrubber control efficiency applied.
2. Fuel oil emission factors per AP-42 Section 1.3, Tables 1.3-6 and 1.3-3, May 2010, for No. 6 fuel oil with 90% scrubber control efficiency applied.

Table B-5b. Nos. 1 and 2 Power Boilers (B001, B002) - Past Actual Emission Factors that Vary from Year-to-Year

Fuel	Pollutant	Emission Factor Units	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Coal[1]	SO_2	lb/ton	38.00	39.14	52.44	38.00	39.14	37.62	36.86	35.72	36.48	36.48
	B001 - Filterable PM	lb/MMBtu	0.086	0.086	0.160	0.160	0.140	0.140	0.050	0.050	0.070	0.070
	B002 - Filterable PM	lb/MMBtu	0.092	0.092	0.160	0.160	0.140	0.140	0.050	0.050	0.070	0.070
	B001 - Filterable PM_{10}	lb/MMBtu	0.060	0.060	0.112	0.112	0.098	0.098	0.035	0.035	0.049	0.049
	B002 - Filterable PM_{10}	lb/MMBtu	0.064	0.064	0.112	0.112	0.098	0.098	0.035	0.035	0.049	0.049
	B001 - Filterable $PM_{2.5}$	lb/MMBtu	0.043	0.043	0.080	0.080	0.070	0.070	0.025	0.025	0.035	0.035
	B002 - Filterable $PM_{2.5}$	lb/MMBtu	0.046	0.046	0.080	0.080	0.070	0.070	0.025	0.025	0.035	0.035
	CPM	lb/MMBtu	0.07	0.07	0.11	0.07	0.07	0.07	0.07	0.06	0.07	0.07
	B001 - Total PM	lb/MMBtu	0.156	0.159	0.268	0.230	0.213	0.209	0.117	0.114	0.136	0.136
	B002 - Total PM	lb/MMBtu	0.162	0.165	0.268	0.230	0.213	0.209	0.117	0.114	0.136	0.136
	B001 - Total PM_{10}	lb/MMBtu	0.130	0.133	0.220	0.182	0.171	0.167	0.102	0.099	0.115	0.115
	B002 - Total PM_{10}	lb/MMBtu	0.134	0.137	0.220	0.182	0.171	0.167	0.102	0.099	0.115	0.115
	B001 - Total $PM_{2.5}$	lb/MMBtu	0.113	0.116	0.188	0.150	0.143	0.139	0.092	0.089	0.101	0.101
	B002 - Total $PM_{2.5}$	lb/MMBtu	0.116	0.119	0.188	0.150	0.143	0.139	0.092	0.089	0.101	0.101
	H_2SO_4	lb/ton	0.18	0.19	0.25	0.18	0.19	0.18	0.18	0.17	0.17	0.17
Fuel Oil[2]	SO_2	lb/Mgal	73.79	72.22	72.22	64.84	54.95	54.95	51.81	47.10	34.54	43.96
	H_2SO_4	lb/Mgal	1.06	1.04	1.04	0.93	0.79	0.79	0.75	0.68	0.50	0.63

1. Coal emission factors per AP-42 Section 1.1 Tables 1.1-3, 1.1-5, and 1.1-19 for PC, dry bottom, tangentially fired boilers and Table 1.1-6.
The SO_2, H_2SO_4, and CPM emission factors rely on the maximum actual sulfur content of the coal fired at the mill during the year.
The filterable total PM (TSP) emission factor is based on the actual stack testing at the mill in a given year. As testing is required beinnually, each test factor is relied upon for a two year period.
2. Fuel oil emission factors per AP-42 Section 1.3 Tables 1.3-1 and 1.3-3 for No. 6 fuel oil, tangentially fired boiler and Table 1.3-6.
The H_2SO_4 emission factor uses the maximum actual sulfur content of the oil fired at the mill during the year.

Table B-6. No. 1 Power Boiler (B001) - Past Actual Emissions*

	Actual Annual Emissions[1]										2-Year Average Annual Actual Emissions									
Pollutant	**2001 (tpy)**	**2002 (tpy)**	**2003 (tpy)**	**2004 (tpy)**	**2005 (tpy)**	**2006 (tpy)**	**2007 (tpy)**	**2008 (tpy)**	**2009 (tpy)**	**2010 (tpy)**	**2001-2002 (tpy)**	**2002-2003 (tpy)**	**2003-2004 (tpy)**	**2004-2005 (tpy)**	**2005-2006 (tpy)**	**2006-2007 (tpy)**	**2007-2008 (tpy)**	**2008-2009 (tpy)**	**2009-2010 (tpy)**	**Maximum (tpy)**
CO	9.75	8.56	6.29	5.68	4.32	5.87	4.08	6.71	5.56	6.27	9.15	7.42	5.98	5.00	5.10	4.98	5.40	6.14	5.92	**9.15**
NO_X	270.42	253.70	184.01	165.33	125.89	173.69	119.87	199.12	113.83	174.03	262.06	218.86	174.67	145.61	149.79	146.78	159.50	156.48	143.93	**262.06**
SO_2	678.09	659.53	638.40	414.98	325.47	433.67	292.54	472.56	237.83	412.82	668.81	648.97	526.69	370.23	379.57	363.10	382.55	355.20	325.33	**668.81**
VOC	1.17	1.04	0.78	0.70	0.54	0.72	0.50	0.82	0.90	0.82	1.10	0.91	0.74	0.62	0.63	0.61	0.66	0.86	0.86	**1.10**
Total PM[2]	69.83	68.06	82.87	63.80	44.99	61.20	23.59	38.31	22.53	39.10	68.94	75.46	73.34	54.40	53.09	42.39	30.95	30.42	30.82	**75.46**
Total PM_{10}[2]	58.28	57.01	68.03	50.49	36.12	48.90	20.57	33.27	19.06	33.06	57.65	62.52	59.26	43.30	42.51	34.73	26.92	26.17	26.06	**62.52**
Total $PM_{2.5}$[2]	50.57	49.65	58.13	41.61	30.20	40.70	18.55	29.91	16.75	29.04	50.11	53.89	49.87	35.91	35.45	29.63	24.23	23.33	22.90	**53.89**
Pb	7.42E-03	7.08E-03	5.12E-03	4.59E-03	3.50E-03	4.84E-03	3.34E-03	5.56E-03	2.78E-03	4.76E-03	7.25E-03	6.10E-03	4.85E-03	4.04E-03	4.17E-03	4.09E-03	4.45E-03	4.17E-03	3.77E-03	**7.25E-03**
H_2SO_4	3.33	3.16	3.06	1.99	1.56	2.08	1.40	2.26	1.14	1.98	3.25	3.11	2.52	1.77	1.82	1.74	1.83	1.70	1.56	**3.25**
Fluoride (non-HF)	4.51E-04	-	3.73E-06	-	4.10E-06	-	-	-	6.72E-05	9.16E-06	2.25E-04	1.87E-06	1.87E-06	2.05E-06	2.05E-06	-	-	3.36E-05	3.82E-05	**2.25E-04**
CO_2e	97,343.22	89,481.58	65,165.45	58,632.73	44,656.42	61,305.01	42,409.37	70,211.84	45,783.30	62,683.36	93,412.40	77,323.52	61,899.09	51,644.57	52,980.72	51,857.19	56,310.61	57,997.57	54,233.33	**93,412.40**

*The No. 1 Power Boiler emissions decreases are included in Step (B) (i.e., five-year netting analysis). As this is a shutdown unit in Step (B), the selected baseline periods do not have to match those for the No. 2 Power Boiler. For each pollutant, a different baseline period may be chosen.

1. Actual annual emisisons calculated based on AP-42 and 40 CFR 98 emission factors (refer to Table B-5) and past actual fuel data.
2. Actual annual PM, PM_{10}, and $PM_{2.5}$ emissions are based on emission factors developed per site-specific test data and AP-42 emission factor for CPM.

Table B-6a. No. 1 Power Boiler (B001) - Past Actual Production Data

	Year									
Parameter	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Actual Fuel Oil Usage (Mgal)	241.70	-	2	-	2.20	-	-	-	36.04	4.91
Actual Fuel Oil Usage (MMBtu)[1]	34,079.70	-	282.00	-	310.20	-	-	-	5,081.08	692.87
Actual Coal Usage (MMBtu)[2]	894,563	856,005	618,363	554,761	422,351	585,597	403,174	672,059	330,251	574,700
Actual Natural Gas Usage (MMscf)	28.3	11.10	16.40	17.90	13.50	9.10	9.64	8.03	185.21	50.021
Actual Natural Gas Usage (MMBtu)[3]	28,979.20	11,366.40	16,793.60	18,329.60	13,824.00	9,318.40	9,866.24	8,220.67	189,659.14	51,221.50
Actual Fuel Sulfur Content - Coal	1.00	1.03	1.38	1.00	1.03	0.99	0.97	0.94	0.96	0.96
Actual Fuel Sulfur Content - Fuel Oil	0.47	0.46	0.46	0.41	0.35	0.35	0.33	0.30	0.22	0.28

1. Fuel oil usage converted from Mgal to MMBtu based on fuel oil heating value of 141 MMBtu/Mgal.
2. Coal usage can be converted from MMBtu to ton based on coal heating value of 25.4 MMBtu/ton.
3. Natural gas usage converted from MMscf to MMBtu based on natural gas heating value of 1,024 Btu/scf.

Table B-7. No. 2 Power Boiler (B002) - Past Actual Emissions*

	Actual Annual Emissions[1]										2-Year Average Annual Actual Emissions									
Pollutant	**2001 (tpy)**	**2002 (tpy)**	**2003 (tpy)**	**2004 (tpy)**	**2005 (tpy)**	**2006 (tpy)**	**2007 (tpy)**	**2008 (tpy)**	**2009 (tpy)**	**2010 (tpy)**	**2001-2002 (tpy)**	**2002-2003 (tpy)**	**2003-2004 (tpy)**	**2004-2005 (tpy)**	**2005-2006 (tpy)**	**2006-2007 (tpy)**	**2007-2008 (tpy)**	**2008-2009 (tpy)**	**2009-2010 (tpy)**	**Maximum (tpy)**
CO	7.88	4.60	6.70	7.00	10.71	5.09	8.51	8.68	8.57	7.37	6.24	5.65	6.85	8.85	7.90	6.80	8.60	8.63	7.97	**8.85**
NO_X	220.42	134.55	189.78	207.50	317.47	150.47	253.15	258.55	140.96	199.02	177.48	162.16	198.64	262.49	233.97	201.81	255.85	199.75	169.99	**262.49**
SO_2	552.84	348.77	657.40	523.83	826.12	375.58	620.71	614.27	257.26	468.79	450.80	503.09	590.62	674.97	600.85	498.15	617.49	435.77	363.03	**674.97**
VOC	0.95	0.56	0.80	0.85	1.29	0.62	1.03	1.05	1.55	0.97	0.76	0.68	0.82	1.07	0.96	0.82	1.04	1.30	1.26	**1.30**
Total PM[2]	59.24	37.30	84.72	80.52	114.11	53.00	50.03	49.80	24.40	44.33	48.27	61.01	82.62	97.32	83.56	51.52	49.91	37.10	34.37	**97.32**
Total PM_{10}[2]	49.15	31.06	69.54	63.72	91.61	42.35	43.62	43.25	20.65	37.49	40.11	50.30	66.63	77.67	66.98	42.98	43.43	31.95	29.07	**77.67**
Total $PM_{2.5}$[2]	42.42	26.90	59.43	52.51	76.61	35.25	39.34	38.88	18.16	32.93	34.66	43.17	55.97	64.56	55.93	37.30	39.11	28.52	25.54	**64.56**
Pb	6.06E-03	3.74E-03	5.24E-03	5.79E-03	8.86E-03	4.20E-03	7.07E-03	7.22E-03	3.05E-03	5.41E-03	4.90E-03	4.49E-03	5.51E-03	7.33E-03	6.53E-03	5.63E-03	7.15E-03	5.14E-03	4.23E-03	**7.33E-03**
H_2SO_4	2.71	1.67	3.20	2.51	3.96	1.80	2.97	2.94	1.24	2.25	2.19	2.44	2.85	3.24	2.88	2.39	2.96	2.09	1.75	**3.24**
Fluoride (non-HF)	3.07E-04	2.26E-05	2.57E-04	5.09E-06	4.18E-05	-	1.39E-05	7.05E-07	1.33E-04	8.34E-05	1.65E-04	1.40E-04	1.31E-04	2.34E-05	2.09E-05	0.00	0.00	6.70E-05	1.08E-04	**1.65E-04**
CO_2e	79,145.32	47,660.83	67,859.82	73,186.83	111,957.28	53,124.88	89,184.08	91,062.04	62,193.34	72,314.32	63,403.07	57,760.32	70,523.32	92,572.06	82,541.08	71,154.48	90,123.06	76,627.69	67,253.83	**92,572.06**

*The No. 2 Power Boiler emissions increases are included in Step (A) (i.e., project emissions increases) of the net emissions increase evaluation. For each pollutant, a different baseline period may be chosen.
1. Actual annual emisisons calculated based on AP-42 and 40 CFR 98 emission factors (refer to Table B-5) and past actual fuel data.
2. Actual annual PM, PM_{10}, and $PM_{2.5}$ emissions are based on emission factors developed per site-specific test data and AP-42 emission factor for CPM.

Table B-7a. No. 2 Power Boiler (B002) - Past Actual Production Data

	Year									
Parameter	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Actual Fuel Oil Usage (Mgal)	164.60	12.10	137.6	2.73	22.40	-	7.43	0.38	71.48	44.73
Actual Fuel Oil Usage (MMBtu)[1]	23,208.60	1,706.10	19,401.60	384.93	3,158.40	-	1,048.19	53.30	10,079.24	6,306.93
Actual Coal Usage (MMBtu)[2]	730,936	452,095	632,028	700,151	1,071,423	507,162	855,193	873,582	356,362	651,408
Actual Natural Gas Usage (MMscf)	23	10.20	11.20	8.50	8.80	8.40	6.09	6.97	406.99	70.147
Actual Natural Gas Usage (MMBtu)[3]	23,552.00	10,444.80	11,468.80	8,704.00	9,011.20	8,601.60	6,233.09	7,132.16	416,757.76	71,830.53
Actual Coal Sulfur Content (%S)	1.00	1.03	1.38	1.00	1.03	0.99	0.97	0.94	0.96	0.96
Actual Fuel Oil Sulfur Content (%S)	0.47	0.46	0.46	0.41	0.35	0.35	0.33	0.30	0.22	0.28

1. Fuel oil usage converted from Mgal to MMBtu based on fuel oil heating value of 141 MMBtu/Mgal.
2. Coal usage can be converted from MMBtu to ton based on coal heating value of 25.4 MMBtu/ton.
3. Natural gas usage converted from MMscf to MMBtu based on natural gas heating value of 1,024 Btu/scf.

Table B-8. No. 2 Power Boiler (B002) Potential Emissions - After Project

Pollutant	Natural Gas Potential Emissions (lb/hr)[1]	(tpy)[2]
CO	4.64	20.33
NO_X	32.87	143.98
SO_2	0.12	0.51
VOC	1.06	4.66
Filterable PM	0.37	1.61
Filterable PM_{10}	0.37	1.61
Filterable $PM_{2.5}$	0.37	1.61
CPM	1.10	4.83
Total PM[3]	1.47	6.44
Total PM_{10}[3]	1.47	6.44
Total $PM_{2.5}$[3]	1.47	6.44
Pb	9.67E-05	4.23E-04
H_2SO_4	-	-
H_2S	-	-
Fluoride (non-HF)	-	-
CO_2e	23,166.71	101,470.20

1. The maximum future hourly emissions are calculated as the future potential emissions.
2. Potential annual emissions are based on 8,760 hours per year of operation.
3. Total particulate emissions are the sum of the filterable particulate and CPM.

Table B-9. No. 2 Power Boiler (B002) Associated Emissions Increase

Pollutant	Potential Emissions (tpy)	Past Actual Emissions (tpy)	Net Emissions Increase[1] (tpy)
CO	20.33	8.85	11.47
NO_X	143.98	262.49	-118.51
SO_2	0.51	674.97	-674.46
VOC	4.66	1.30	3.36
Total PM[2]	6.44	97.32	-90.88
Total PM_{10}[2]	6.44	77.67	-71.23
Total $PM_{2.5}$[2]	6.44	64.56	-58.13
Pb	4.23E-04	7.33E-03	-6.90E-03
H_2SO_4	-	3.24	-3.24
Fluoride (non-HF)	-	1.65E-04	-1.65E-04
CO_2e	101,470.20	92,572.06	8,898.14

1. The net emissions increases from the No. 2 Power Boiler is equal to the future potential emissions minus the past actual emissions.
2. Total particulate emissions are the sum of the filterable particulate and CPM.

Table B-10. Bark Transfer and Handling (A910) Potential Emissions Increases from Proposed Project

Hourly Bark Throughput Increase[1] (ton/hr)			83.24
Annual Bark Throughput Increase[2] (tpy)			729,216
No. Additional Transfer Points in System[3]			9
Pollutant	**Emission Factor[4] (lb/ton)**	**Potential Emissions[5] (lb/hr)**	**(tpy)**
Filterable PM	4.82E-05	3.61E-02	1.58E-01
Filterable PM_{10}	2.28E-05	1.71E-02	7.47E-02
Filterable $PM_{2.5}$	3.45E-06	2.58E-03	1.13E-02

1. Hourly bark throughput increase based on boiler's wood heat input capacity (620 MMBtu/hr) and wood's heat content (7.45 MMBtu/ton).
2. Annual bark throughput increase assumes 8,760 hours per year of operation.
3. Number of additional transfer points provided via email from Paul Douglas (Larson Engineering) on January 24, 2011.
4. Emission factor per AP-42 Section 13.2.4, *Aggregate Handling and Storage Piles* , Predictive Emission Factor Equations, November 2006, as follows:

E = k(0.0032)[(U/5)^1.3]/[(M/2)^1.4]

where E = emission factor in pounds per ton

k = particle size multiplier as follows:

	0.74	for PM
	0.35	for PM_{10}
	0.053	for $PM_{2.5}$
U =	8	mph; average wind speed for Macon, GA
M =	50	%; moisture content

5. Potential emissions = Emission factor (lb/ton) × Bark throughput (ton/time period) × No. of transfer points.

Table B-11. Bark Hog Tower and Hammer Hog (A911) Potential Emissions Increases from Proposed Project

Hourly Bark Throughput Increase[1] (ton/hr)			41.62
Annual Bark Throughput Increase[2] (tpy)			364,608
Pollutant	**Emission Factor[3,4,5] (lb/ton)**	**Potential Emissions[6] (lb/hr)**	**(tpy)**
Filterable PM	2.4E-02	1.00	4.38
Filterable PM_{10}	1.4E-02	0.60	2.63
Filterable $PM_{2.5}$	1.4E-02	0.60	2.63

1. Hourly bark throughput increase based on boiler's wood heat input capacity (620 MMBtu/hr) and wood's heat content (7.45 MMBtu/ton), and conservatively assumes that 50% of the bark will be resized in the bark hog per email from Paul Douglas (Larson Engineering) on December 21, 2010.

2. Annual bark throughput increase assumes 8,760 hours per year of operation.

3. TSP emission factor for "log debarking" based on U.S. EPA AP-42, Section 10.3-1, *Wood Products Industry,* Table 10.3-1, September 1985. www.epa.gov/ttn/chief/old/ap42/4th_edition/ap42_4thed_withsuppsa_f.pdf. Also recommended by Bay Area Air Quality Management District (BAAQMD) Permit Handbook for biomass tub grinding operations. www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_11_13.pdf.

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

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

6. Potential emissions = Emission factor (lb/ton) × Bark Throughput (ton/time period).

Table B-12. Fly Ash Silo (B903) Potential Emissions

Pollutant	Exhaust Flow Rate[1] (acfm)	Exit Grain Loading[1] (gr/ft^3)	Potential Emissions (lb/hr)[2]	Potential Emissions (tpy)[3]
Filterable PM	1,000	0.01	0.09	0.38
Filterable PM_{10}		0.01	0.09	0.38
Filterable $PM_{2.5}$		0.01	0.09	0.38

*Note that the fly ash silo discharge is equipped with an unloading conditioner to wet the material, and all fly ash conveyors are enclosed. Thus, there are no fugitive emissions from fly ash handling. Additionally, bottom ash and boiler hopper ash are not dusty and will be discharged into a bin inside the boiler house; thus, potential emissions are assumed to be negligible.

1. Exhaust flow rate and exit grain loading provided via email from Paul Douglas (Larson Engineering) on December 21, 2010.
2. Potential emissions (lb/hr) = Exhaust flow rate (acfm) × Exit grain loading ($grain/ft^3$) × (1 lb/7,000 grains) × (60 min/hr).
3. Annual emissions based on 8,760 hours of operation per year.

Table B-13. Sand Silo (B904) Potential Emissions

Pollutant	Exhaust Flow Rate[1] (acfm)	Exit Grain Loading[1] (gr/ft^3)	Potential Emissions (lb/hr)[2]	(tpy)[3]
Filterable PM		0.01	7.14E-04	3.13E-03
Filterable PM_{10}	8.33	0.01	7.14E-04	3.13E-03
Filterable $PM_{2.5}$		0.01	7.14E-04	3.13E-03

*Note that the sand handling and transfer will occur in an enclosed system. Thus, there are no fugitive emissions from sand handling.

1. Exhaust flow rate and exit grain loading provided via email from Paul Douglas (Larson Engineering) on December 21, 2010; assumes the silo only exhausts during filling, which occurs over the period of one hour.
2. Potential emissions (lb/hr) = Exhaust flow rate (acfm) × Exit grain loading ($grain/ft^3$) × (1 lb/7,000 grains) × (60 min/hr).
3. Annual emissions based on continuous operation 8,760 hours per year, although actual operation is anticipated to be less as the control device will only operate while the silo is filled.

Table B-14. Cooling Tower (CT01) Potential Emissions

Cooling Tower Capacity[1] (gpm)	Total Dissolved Solids[1] (mg/L)	Drift Loss[1] (%)	Drift Mass Governed by Atmospheric Dispersion[2] (%)	Drift Mass Flow Rate[3] (lb/hr)	Total PM/PM_{10} Potential Emissions[4,5]		Total $PM_{2.5}$ Potential Emissions[5,6]	
					(lb/hr)	(tpy)	(lb/hr)	(tpy)
38,000	2,500	0.005%	31.3%	951.33	0.74	3.26	0.45	1.96

1. Provided via email from Paul Douglas (Larson Engineering) on December 21, 2010.
2. Based on *Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1* Technical Report EPA 600 7-79-251a, November 1979.
3. Drift mass flow rate (lb/hr) = Cooling tower capacity (gpm) x Density of water (8.34 lb/gal) x 60 min/hour x Drift loss (%) .
4. Hourly PM/PM_{10} emission rate (lb/hr) = Drift mass flow rate (lb/hr) x Dispersion Factor (%) x TDS (mg/L)/(1,000,000).
5. Annual PM/PM_{10} emission rate (ton/yr) = Hourly emission rate (lb/hr) x 8,760 (hours/yr)/(2000 lb/ton).
6. Hourly and annual $PM_{2.5}$ emission rate = 60% * PM_{10} emission rate (lb/hr). $PM_{2.5}$ fraction of PM_{10} in cooling tower exhaust was obtained from California Emissions Inventory Development and Reporting System (CEIDARS).

Table B-15. Sorbent Silo (B905) Potential Emissions

Pollutant	Exhaust Flow Rate[1] (acfm)	Exit Grain Loading[1] (gr/ft^3)	Potential Emissions (lb/hr)[2]	Potential Emissions (tpy)[3]
Filterable PM	16.67	0.01	1.43E-03	6.26E-03
Filterable PM_{10}		0.01	1.43E-03	6.26E-03
Filterable $PM_{2.5}$		0.01	1.43E-03	6.26E-03

*Note that the sorbent handling and transfer will occur in an enclosed system. Thus, there are no fugitive emissions from sorbent handling.

1. Exhaust flow rate and exit grain loading provided via email from Paul Douglas (Larson Engineering) on December 21, 2010; assumes the silo only exhausts during filling, which occurs over the period of one hour.

2. Potential emissions (lb/hr) = Exhaust flow rate (acfm) × Exit grain loading ($grain/ft^3$) × (1 lb/7,000 grains) × (60 min/hr).

3. Annual emissions based on continuous operation 8,760 hours per year, although actual operation is anticipated to be less as the control device will only operate while the silo is filled.

Table B-16. Sorbent Usage Potential CO_2 Emissions

Parameter	Value	Units	Ref
Hourly Sorbent Throughput	250.00	lb/hr	1
Annual Sorbent Throughput	1,095	tpy	2
Moles CO_2 Released per Mole HCl Captured	0.7	-	3
Molecular Weight - CO_2	44	lb/lb-mol	4
Molecular Weight - Sorbent	226	lb/lb-mol	4
Hourly CO_2 Emission Rate	32.45	lb/hr	5
Annual CO_2 Emission Rate	142.14	tpy	5

1. Expected hourly sorbent usage rate provided by Paul Douglas (Larson Engineering) on November 23, 2010.
2. Annual throughput based on continuous usage of dry sorbent injection for 8,760 hours per year, although actual operation is anticipated to be less as GPI is proposing to only utilize dry sorbent injection on an as needed basis.
3. The ratio of CO_2 emitted to HCl removed is based on the usage of Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) as the sorbent and the following chemical reaction:

$$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O + 3\ HCl \rightarrow 3\ NaCl + 2\ CO_2 + 4\ H_2O$$

4. Calculated based on the molecular formula for each compound and the elements' atomic weights as follows:

Sodium atomic weight:	22.99
Hydrogen atomic weight:	1.00
Oxygen atomic weight:	16.00
Carbon atomic weight:	12.00

5. Per 40 CFR 98.33(d)(1), Potential CO_2 emissions = Sorbent throughput × (Moles CO_2 released / Moles HCl captured) × (CO_2 molecular weight / Sorbent molecular weight).

Table B-17. Paved Roads Potential Fugitive Emissions Increases from Proposed Project

Source	Truck Weight Empty[1] (tons)	Truck Weight Loaded[1] (tons)	Average Weight (W) (tons)	Distance Traveled per Round Trip[1] (ft)	Average Trips Per Day[1]	Events Per Year (Days)	Vehicle Miles Traveled (VMT/day	Vehicle Miles Traveled (VMT/yr)	Emission Factor[2] (lb/VMT) PM	Emission Factor[2] (lb/VMT) PM_{10}	Emission Factor[2] (lb/VMT) $PM_{2.5}$	Potential Fugitive Emissions[3] Filterable PM (lb/hr)	Filterable PM (tpy)	Filterable PM_{10} (lb/hr)	Filterable PM_{10} (tpy)	Filterable $PM_{2.5}$ (lb/hr)	Filterable $PM_{2.5}$ (tpy)
Biomass Delivery	15	40	27.5	6,400	96	365	116.36	42,473	0.13	0.03	0.01	0.62	2.74	0.12	0.55	0.03	0.13
Sand Delivery	15	40	27.5	3,000	0.07	365	0.04	15	0.13	0.03	0.01	2.20E-04	9.62E-04	4.4E-05	1.9E-04	1.1E-05	4.7E-05
Ammonia Delivery[4]	15	32	23.3	1,000	0.29	365	0.05	20	0.11	0.02	0.01	2.45E-04	1.07E-03	4.9E-05	2.1E-04	1.2E-05	5.3E-05
Dry Sorbent Delivery	15	40	27.5	3,000	0.14	365	0.08	30	0.13	0.03	0.01	4.36E-04	1.91E-03	8.7E-05	3.8E-04	2.1E-05	9.4E-05
Fly Ash Removal	15	40	27.5	3,000	3.86	365	2.19	800	0.13	0.03	0.01	0.01	0.05	2.4E-03	0.01	5.8E-04	2.5E-03
Bottom Ash Removal[5]	15	40	27.5	3,000	3.86	365	2.19	800	0.13	0.03	0.01	0.01	0.05	2.4E-03	0.01	5.8E-04	2.5E-03
Total Road Emissions												**0.65**	**2.84**	**0.13**	**0.57**	**0.03**	**0.14**

1. Information provided by Paul Douglas (Larson Engineering) on October 8, 2010, and November 23, 2010.
2. Emission Factor (lb/VMT) = $[k\ (sL)^{0.91} \times (W)^{1.02}] \times [1\text{-}P/(4N)]$, per AP-42 Section 13.2.1, *Paved Roads*, Equation 2, January 2011, with variables defined as follows:

k (lb/VMT) =	0.011	Particle size multiplier for PM per AP-42, Table 13.2.1-1
k (lb/VMT) =	0.0022	Particle size multiplier for PM_{10} per AP-42, Table 13.2.1-1
k (lb/VMT) =	0.00054	Particle size multiplier for $PM_{2.5}$ per AP-42, Table 13.2.1-1
sL (g/m^2) =	0.4	Based on AWMA Air Pollution Engineering Manual second edition, page 126.
P =	120	No. days with rainfall greater than 0.01 inch, Per AP-42, Section 13.2.1 - Paved Roads, Figure 13.2.1-2
N =	365	Days in averaging period

Note GPI conservatively estimated hourly and annual emissions using the emission factor on a daily basis because an emission factor on an hourly basis calculated per Equation 3 results in lower potential emissions.

3. Potential emissions calculated as appropriate emission factor multiplied by vehicle miles traveled per time period.
4. Ammonia truck weights provided by Kathleen Wheeler (GPI) via email on December 13, 2010.
5. Assumes bottom ash removal occurs with the same frequency as fly ash removal; however, GPI anticipates less bottom ash generation and thus less frequent trucks required for removal.

Table B-18. Maximum Heat Input for Each Type of Fuel Fired at Each Firing Rate

New Biomass Boiler Max Heat Input	620 MMBtu/hr		
Hours of Operation	8,760 hrs/yr		
Fuel Combusted	**% of Maximum Heat Input**	**Fuel Heat Input Value**	**Units**
Biomass	100%	620.00	MMBtu/hr
Natural Gas (short term)	40%	249.00	MMBtu/hr
Natural Gas (long term)	10%	62.00	MMBtu/hr

Table B-18a. Heat Input and Steaming Rates for Biomass Combustion

Fuel Combusted	**Anticipated Wood+Sludge Combination[1]**	**Maximum Wood+Sludge Combustion[2]**
Biomass Heat Input (MMBtu/hr)	571.10	620.00
Associated Steam Production (lb/hr)	350,000	379,968

1. Information provided via email from Aku Raino (Andritz) to GPI on January 6, 2011.
2. Based on maximum heat input capacity of the boiler. Calculated associated steam production as maximum heat input capacity of boiler multiplied by the ratio of the anticipated steam production to anticipated heat input.

Table B-19. New Biomass Boiler Maximum Potential Hazardous Air Pollutant and Toxic Air Pollutant Emissions

	Pollutant Classifications		Emission Factors			Potential Emissions [3]					
			Biomass[1]		Natural Gas[2]	Biomass		Natural Gas		Maximum	
Pollutant	**Georgia TAP (Yes/No)**	**HAP (Yes/No)**	**(lb/MMBtu)**	**(lb/lb steam)**	**(lb/MMscf)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
1,1,1-Trichloroethane [methyl chloroform]	Yes	Yes	3.10E-05	5.06E-08	-	1.92E-02	8.42E-02	-	-	1.92E-02	8.42E-02
1,2-Dibromoethene	No	Yes	5.50E-05	8.97E-08	-	3.41E-02	1.49E-01	-	-	3.41E-02	1.49E-01
1,2-Dichloroethane [ethylene dichloride]	Yes	Yes	2.90E-05	4.73E-08	-	1.80E-02	7.88E-02	-	-	1.80E-02	7.88E-02
1,2-Dichloropropane	Yes	Yes	3.30E-05	5.38E-08	-	2.05E-02	8.96E-02	-	-	2.05E-02	8.96E-02
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	Yes	8.60E-12	1.40E-14	-	5.33E-09	2.34E-08	-	-	5.33E-09	2.34E-08
2,3,7,8-Tetrachlorodibenzo-p-furans	No	Yes	9.00E-11	1.47E-13	-	5.58E-08	2.44E-07	-	-	5.58E-08	2.44E-07
2,4,6-Trichlorophenol	Yes	Yes	2.20E-08	3.59E-11	-	1.36E-05	5.97E-05	-	-	1.36E-05	5.97E-05
2,4-Dinitrophenol	Yes	Yes	1.80E-07	2.94E-10	-	1.12E-04	4.89E-04	-	-	1.12E-04	4.89E-04
Methyl ethyl ketone [2-butanone]	Yes	No	-	-	-	-	-	-	-	0.00E+00	0.00E+00
2-Chloronaphthalene	No	Yes	2.40E-09	3.92E-12	-	1.49E-06	6.52E-06	-	-	1.49E-06	6.52E-06
2-Chlorophenol	Yes	No	2.40E-08	3.92E-11	-	1.49E-05	6.52E-05	-	-	1.49E-05	6.52E-05
2-Methyl naphthalene (POM)	Yes	Yes	1.60E-07	2.61E-10	2.40E-05	9.92E-05	4.34E-04	5.84E-06	6.36E-06	9.92E-05	4.34E-04
2-Nitrophenol	Yes	No	2.40E-07	3.92E-10	-	1.49E-04	6.52E-04	-	-	1.49E-04	6.52E-04
3-Methylchloranthrene (POM)	Yes	Yes	-	-	1.80E-06	-	-	4.38E-07	4.77E-07	4.38E-07	4.77E-07
4-Nitrophenol	Yes	Yes	1.10E-07	1.79E-10	-	6.82E-05	2.99E-04	-	-	6.82E-05	2.99E-04
7,12-Dimethylbenz(a)anthracene (POM)	Yes	Yes	-	-	1.60E-05	-	-	3.89E-06	4.24E-06	3.89E-06	4.24E-06
Acenaphthene (POM)	No	Yes	9.10E-07	1.48E-09	1.80E-06	5.64E-04	2.47E-03	4.38E-07	4.77E-07	5.64E-04	2.47E-03
Acenaphthylene (POM)	No	Yes	5.00E-06	8.16E-09	1.80E-06	3.10E-03	1.36E-02	4.38E-07	4.77E-07	3.10E-03	1.36E-02
Acetaldehyde	Yes	Yes	4.66E-05	7.60E-08	-	2.89E-02	1.26E-01	-	-	2.89E-02	1.26E-01
Acetone	Yes	No	1.90E-04	3.10E-07	-	1.18E-01	5.16E-01	-	-	1.18E-01	5.16E-01
Acetophenone	Yes	Yes	3.20E-09	5.22E-12	-	1.98E-06	8.69E-06	-	-	1.98E-06	8.69E-06
Acrolein	Yes	Yes	9.17E-06	1.50E-08	-	5.69E-03	2.49E-02	-	-	5.69E-03	2.49E-02
Anthracene (POM)	Yes	Yes	3.00E-06	4.90E-09	2.40E-06	1.86E-03	8.15E-03	5.84E-07	6.36E-07	1.86E-03	8.15E-03
Antimony	Yes	Yes	7.90E-06	1.29E-08	-	4.90E-03	2.15E-02	-	-	4.90E-03	2.15E-02
Arsenic	Yes	Yes	2.20E-05	3.59E-08	2.00E-04	1.36E-02	5.97E-02	4.86E-05	5.30E-05	1.36E-02	5.97E-02
Barium	Yes	No	1.70E-04	2.77E-07	4.40E-03	1.05E-01	4.62E-01	1.07E-03	1.17E-03	1.05E-01	4.62E-01
Benzaldehyde	Yes	No	8.50E-07	1.39E-09	-	5.27E-04	2.31E-03	-	-	5.27E-04	2.31E-03
Benzene	Yes	Yes	2.53E-05	4.13E-08	2.10E-03	1.57E-02	6.87E-02	5.11E-04	5.57E-04	1.57E-02	6.87E-02
Benzo(a)anthracene (POM)	Yes	Yes	6.50E-08	1.06E-10	1.80E-06	4.03E-05	1.77E-04	4.38E-07	4.77E-07	4.03E-05	1.77E-04
Benzo(a)pyrene (POM)	Yes	Yes	2.60E-06	4.24E-09	1.20E-06	1.61E-03	7.06E-03	2.92E-07	3.18E-07	1.61E-03	7.06E-03
Benzo(k)fluoranthene (POM)	Yes	Yes	3.60E-08	5.87E-11	1.80E-06	2.23E-05	9.78E-05	4.38E-07	4.77E-07	2.23E-05	9.78E-05
Benzo(b)fluoranthene (POM)	Yes	Yes	-	-	1.80E-06	-	-	4.38E-07	4.77E-07	4.38E-07	4.77E-07
Benzo(e)pyrene	No	Yes	2.60E-09	4.24E-12	-	1.61E-06	7.06E-06	-	-	1.61E-06	7.06E-06
Benzo(g,h,i)perylene (POM)	No	Yes	9.30E-08	1.52E-10	1.20E-06	5.77E-05	2.53E-04	2.92E-07	3.18E-07	5.77E-05	2.53E-04
Benzo(j,k)fluoranthene	Yes	Yes	1.60E-07	2.61E-10	-	9.92E-05	4.34E-04	-	-	9.92E-05	4.34E-04
Benzo(k)fluoranthene (POM)	Yes	Yes	3.60E-08	5.87E-11	1.80E-06	2.23E-05	9.78E-05	4.38E-07	4.77E-07	2.23E-05	9.78E-05
Benzoic acid	Yes	No	4.70E-08	7.67E-11	-	2.91E-05	1.28E-04	-	-	2.91E-05	1.28E-04
Beryllium	Yes	Yes	1.10E-06	1.79E-09	1.20E-05	6.82E-04	2.99E-03	2.92E-06	3.18E-06	6.82E-04	2.99E-03
Bis (2-ethylhexyl) phthalate	Yes	Yes	4.70E-08	7.67E-11	-	2.91E-05	1.28E-04	-	-	2.91E-05	1.28E-04
Bromomethane [methyl bromide]	Yes	Yes	1.50E-05	2.45E-08	-	9.30E-03	4.07E-02	-	-	9.30E-03	4.07E-02
Butane	Yes	No	-	-	2.10E+00	-	-	5.11E-01	5.57E-01	5.11E-01	5.57E-01
Cadmium	Yes	Yes	4.10E-06	6.69E-09	1.10E-03	2.54E-03	1.11E-02	2.67E-04	2.92E-04	2.54E-03	1.11E-02
Carbazole	Yes	Yes	1.80E-06	2.94E-09	-	1.12E-03	4.89E-03	-	-	1.12E-03	4.89E-03
Carbon tetrachloride	Yes	Yes	4.50E-05	7.34E-08	-	2.79E-02	1.22E-01	-	-	2.79E-02	1.22E-01
Chlorine	Yes	Yes	7.90E-04	1.29E-06	-	4.90E-01	2.15E+00	-	-	4.90E-01	2.15E+00
Chlorobenzene	Yes	Yes	3.30E-05	5.38E-08	-	2.05E-02	8.96E-02	-	-	2.05E-02	8.96E-02
Chloroform	Yes	Yes	2.80E-05	4.57E-08	-	1.74E-02	7.60E-02	-	-	1.74E-02	7.60E-02
Chloromethane [methyl chloride]	Yes	Yes	2.30E-05	3.75E-08	-	1.43E-02	6.25E-02	-	-	1.43E-02	6.25E-02
Chromium	Yes	Yes	2.10E-05	3.43E-08	1.40E-03	1.30E-02	5.70E-02	3.40E-04	3.71E-04	1.30E-02	5.70E-02
Chromium VI	Yes	Yes	3.50E-06	5.71E-09	-	2.17E-03	9.50E-03	-	-	2.17E-03	9.50E-03
Chrysene (POM)	Yes	Yes	3.80E-08	6.20E-11	-	2.36E-05	1.03E-04	-	-	2.36E-05	1.03E-04
Cobalt	Yes	Yes	6.50E-06	1.06E-08	8.40E-05	4.03E-03	1.77E-02	2.04E-05	2.23E-05	4.03E-03	1.77E-02
Copper	Yes	No	4.90E-05	8.00E-08	8.50E-04	3.04E-02	1.33E-01	2.07E-04	2.25E-04	3.04E-02	1.33E-01
Crotonaldehyde	Yes	No	9.90E-06	1.62E-08	-	6.14E-03	2.69E-02	-	-	6.14E-03	2.69E-02
Decachlorobiphenyl	Yes	Yes	2.70E-10	4.41E-13	-	1.67E-07	7.33E-07	-	-	1.67E-07	7.33E-07
Dibenzo(a,h)anthracene (POM)	Yes	Yes	9.10E-09	1.48E-11	1.20E-06	5.64E-06	2.47E-05	2.92E-07	3.18E-07	5.64E-06	2.47E-05
Dichlorobenzene	Yes	Yes	-	-	1.20E-03	-	-	2.92E-04	3.18E-04	2.92E-04	3.18E-04
Dichlorobiphenyl	Yes	Yes	7.40E-10	1.21E-12	-	4.59E-07	2.01E-06	-	-	4.59E-07	2.01E-06
Methylene chloride [dichloromethane]	Yes	Yes	2.90E-04	4.73E-07	-	1.80E-01	7.88E-01	-	-	1.80E-01	7.88E-01
Ethane	Yes	No	-	-	3.10E+00	-	-	7.54E-01	8.22E-01	7.54E-01	8.22E-01
Ethylbenzene	Yes	Yes	3.10E-05	5.06E-08	-	1.92E-02	8.42E-02	-	-	1.92E-02	8.42E-02
Fluoranthene (POM)	No	Yes	1.60E-06	2.61E-09	3.00E-06	9.92E-04	4.34E-03	7.29E-07	7.96E-07	9.92E-04	4.34E-03
Fluorene (POM)	No	Yes	3.40E-06	5.55E-09	2.80E-06	2.11E-03	9.23E-03	6.81E-07	7.43E-07	2.11E-03	9.23E-03
Formaldehyde	Yes	Yes	2.29E-04	3.73E-07	7.50E-02	1.42E-01	6.21E-01	1.82E-02	1.99E-02	1.42E-01	6.21E-01
Heptachlorobiphenyl	Yes	Yes	6.60E-11	1.08E-13	-	4.09E-08	1.79E-07	-	-	4.09E-08	1.79E-07
Heptachlorodibenzo-p-dioxins	No	Yes	2.00E-09	3.26E-12	-	1.24E-06	5.43E-06	-	-	1.24E-06	5.43E-06
Heptachlorodibenzo-p-furans	No	Yes	2.40E-10	3.92E-13	-	1.49E-07	6.52E-07	-	-	1.49E-07	6.52E-07
Hexachlorobiphenyl	Yes	Yes	5.50E-10	8.97E-13	-	3.41E-07	1.49E-06	-	-	3.41E-07	1.49E-06
Hexachlorodibenzo-p-dioxins	Yes	Yes	1.60E-06	2.61E-09	-	9.92E-04	4.34E-03	-	-	9.92E-04	4.34E-03
Hexachlorodibenzo-p-furans	No	Yes	2.80E-10	4.57E-13	-	1.74E-07	7.60E-07	-	-	1.74E-07	7.60E-07
Hexanal	Yes	No	7.00E-06	1.14E-08	-	4.34E-03	1.90E-02	-	-	4.34E-03	1.90E-02
Hydrogen chloride*	Yes	Yes	N/A	N/A	-	2.26E+00	9.90E+00	-	-	2.26E+00	9.90E+00
Hydrogen fluoride [hydrofluoric acid]	Yes	Yes	2.22E-04	3.62E-07	-	1.38E-01	6.02E-01	-	-	1.38E-01	6.02E-01
Indeno(1,2,3-c,d)pyrene (POM)	Yes	Yes	8.70E-08	1.42E-10	1.80E-06	5.39E-05	2.36E-04	4.38E-07	4.77E-07	5.39E-05	2.36E-04
Iron	No	No	9.90E-04	1.62E-06	-	6.14E-01	2.69E+00	-	-	6.14E-01	2.69E+00
Isobutyraldehyde	Yes	No	1.20E-05	1.96E-08	-	7.44E-03	3.26E-02	-	-	7.44E-03	3.26E-02
Lead	Yes	Yes	4.80E-05	7.83E-08	5.00E-05	2.98E-02	1.30E-01	1.22E-05	1.33E-05	2.98E-02	1.30E-01
Manganese	Yes	Yes	3.61E-04	5.89E-07	3.80E-04	2.24E-01	9.81E-01	9.24E-05	1.01E-04	2.24E-01	9.81E-01
Mercury	Yes	Yes	3.50E-06	5.71E-09	2.60E-04	2.17E-03	9.50E-03	6.32E-05	6.90E-05	2.17E-03	9.50E-03
Methane	Yes	No	2.10E-02	3.43E-05	-	1.30E+01	5.70E+01	-	-	1.30E+01	5.70E+01
Methanol	Yes	Yes	1.62E-03	2.64E-06	-	1.00E+00	4.39E+00	-	-	1.00E+00	4.39E+00
Molybdenum	Yes	No	2.10E-06	3.43E-09	1.10E-03	1.30E-03	5.70E-03	2.67E-04	2.92E-04	1.30E-03	5.70E-03
Monochlorobiphenyl	No	Yes	2.20E-10	3.59E-13	-	1.36E-07	5.97E-07	-	-	1.36E-07	5.97E-07
Naphthalene	Yes	Yes	9.70E-05	1.58E-07	6.10E-04	6.01E-02	2.63E-01	1.48E-04	1.62E-04	6.01E-02	2.63E-01
n-Hexane	Yes	Yes	-	-	1.80E+00	-	-	4.38E-01	4.77E-01	4.38E-01	4.77E-01
Nickel	Yes	Yes	3.30E-05	5.38E-08	2.10E-03	2.05E-02	8.96E-02	5.11E-04	5.57E-04	2.05E-02	8.96E-02
Octachlorodibenzo-p-dioxins	No	Yes	6.60E-08	1.08E-10	-	4.09E-05	1.79E-04	-	-	4.09E-05	1.79E-04
Octachlorodibenzo-p-furans	No	Yes	8.80E-11	1.44E-13	-	5.46E-08	2.39E-07	-	-	5.46E-08	2.39E-07
o-Tolualdehyde	No	No	7.20E-06	1.17E-08	-	4.46E-03	1.96E-02	-	-	4.46E-03	1.96E-02
o-Xylene	Yes	Yes	2.50E-05	4.08E-08	-	1.55E-02	6.79E-02	-	-	1.55E-02	6.79E-02
Pentachlorobiphenyl	No	Yes	1.20E-09	1.96E-12	-	7.44E-07	3.26E-06	-	-	7.44E-07	3.26E-06
Pentachlorodibenzo-p-dioxins	No	Yes	1.50E-09	2.45E-12	-	9.30E-07	4.07E-06	-	-	9.30E-07	4.07E-06
Pentachlorodibenzo-p-furans	No	Yes	4.20E-10	6.85E-13	-	2.60E-07	1.14E-06	-	-	2.60E-07	1.14E-06
Pentachlorophenol	Yes	Yes	5.10E-08	8.32E-11	-	3.16E-05	1.38E-04	-	-	3.16E-05	1.38E-04
Pentane	Yes	No	-	-	2.60E+00	-	-	6.32E-01	6.90E-01	6.32E-01	6.90E-01
Perylene	No	Yes	5.20E-10	8.48E-13	-	3.22E-07	1.41E-06	-	-	3.22E-07	1.41E-06
Phenanthrene (POM)	Yes	Yes	7.00E-06	1.14E-08	1.70E-05	4.34E-03	1.90E-02	4.13E-06	4.51E-06	4.34E-03	1.90E-02
Phenol	Yes	Yes	5.10E-05	8.32E-08	-	3.16E-02	1.38E-01	-	-	3.16E-02	1.38E-01
Phosphorus	Yes	Yes	2.70E-05	4.41E-08	-	1.67E-02	7.33E-02	-	-	1.67E-02	7.33E-02
Potassium	No	No	3.90E-02	6.36E-05	-	2.42E+01	1.06E+02	-	-	2.42E+01	1.06E+02
Propane	Yes	No	-	-	1.60E+00	-	-	3.89E-01	4.24E-01	3.89E-01	4.24E-01
Propionaldehyde [propanal]	Yes	Yes	6.10E-05	9.95E-08	-	3.78E-02	1.66E-01	-	-	3.78E-02	1.66E-01
p-Tolualdehyde	No	No	1.10E-05	1.79E-08	-	6.82E-03	2.99E-02	-	-	6.82E-03	2.99E-02
Pyrene (POM)	Yes	Yes	3.70E-06	6.04E-09	5.00E-06	2.29E-03	1.00E-02	1.22E-06	1.33E-06	2.29E-03	1.00E-02
Selenium	Yes	Yes	2.80E-06	4.57E-09	2.40E-05	1.74E-03	7.60E-03	5.84E-06	6.36E-06	1.74E-03	7.60E-03
Silver	Yes	No	1.70E-03	2.77E-06	-	1.05E+00	4.62E+00	-	-	1.05E+00	4.62E+00
Sodium	No	No	3.60E-04	5.87E-07	-	2.23E-01	9.78E-01	-	-	2.23E-01	9.78E-01
Strontium	No	No	1.00E-05	1.63E-08	-	6.20E-03	2.72E-02	-	-	6.20E-03	2.72E-02
Styrene	Yes	Yes	5.60E-07	9.14E-10	-	3.47E-04	1.52E-03	-	-	3.47E-04	1.52E-03
Tetrachlorobiphenyl	Yes	Yes	2.50E-09	4.08E-12	-	1.55E-06	6.79E-06	-	-	1.55E-06	6.79E-06
Tetrachlorodibenzo-p-dioxins	Yes	Yes	4.70E-10	7.67E-13	-	2.91E-07	1.28E-06	-	-	2.91E-07	1.28E-06
Tetrachlorodibenzo-p-furans	No	Yes	7.50E-10	1.22E-12	-	4.65E-07	2.04E-06	-	-	4.65E-07	2.04E-06
Tetrachloroethylene [perchloroethylene]	Yes	Yes	3.80E-05	6.20E-08	-	2.36E-02	1.03E-01	-	-	2.36E-02	1.03E-01
Tin	Yes	No	2.30E-05	3.75E-08	-	1.43E-02	6.25E-02	-	-	1.43E-02	6.25E-02
Titanium	Yes	No	2.00E-05	3.26E-08	-	1.24E-02	5.43E-02	-	-	1.24E-02	5.43E-02
Toluene	Yes	Yes	5.72E-06	9.33E-09	3.40E-03	3.55E-03	1.55E-02	8.27E-04	9.02E-04	3.55E-03	1.55E-02
Trichlorobiphenyl	Yes	Yes	2.60E-09	4.24E-12	-	1.61E-06	7.06E-06	-	-	1.61E-06	7.06E-06
Trichloroethylene	Yes	Yes	3.00E-05	4.90E-08	-	1.86E-02	8.15E-02	-	-	1.86E-02	8.15E-02
Trichlorofluoromethane	Yes	No	4.10E-05	6.69E-08	-	2.54E-02	1.11E-01	-	-	2.54E-02	1.11E-01
Vanadium	Yes	No	9.80E-07	1.60E-09	2.30E-03	6.08E-04	2.66E-03	5.59E-04	6.10E-04	6.08E-04	2.66E-03
Vinyl chloride	Yes	Yes	1.80E-05	2.94E-08	-	1.12E-02	4.89E-02	-	-	1.12E-02	4.89E-02
Yttrium	Yes	No	3.00E-07	4.90E-10	-	1.86E-04	8.15E-04	-	-	1.86E-04	8.15E-04
Zinc	No	No	4.20E-04	6.85E-07	2.90E-02	2.60E-01	1.14E+00	7.05E-03	7.69E-03	2.60E-01	1.14E+00
Toxic Air Pollutant Total						**44.37**	**194.35**	**2.35**	**2.56**	**46.71**	**196.90**
Hazardous Air Pollutant Total						**5.02**	**21.99**	**0.46**	**0.50**	**5.46**	**22.46**
Maximum Hazardous Air Pollutant						**2.26**	**9.90**	**0.44**	**0.48**	**2.26**	**9.90**

1. Emission factors (lb/MMBtu) for biomass taken from AP-42 Chapter 1.6. Lb/Lb steam factors estimated based on design steaming capabilities of the boiler. Intended to facilitate future actual emission calculations.
2. Emission factors for natural gas firing taken from AP-42 Chapter 1.4, "Natural Gas Combustion," Tables 1.4-3 and 1.4-4 (July 1998).
3. Biomass short and long term emissions based on 100% biomass fuel. Natural gas short term emissions based on the maximum natural gas burner capacity. Natural gas long term emissions are based on a maximum of 10% of the boiler heat input capacity on an annual basis. Annual emissions are based on the 8,760 hours of operation.
*GPI is proposing to limit HCl emissions from the No. 3 Biomass Boiler to < 10 tpy.

Table B-20. Maximum Hourly Fuel Consumption for Fuel Fired[1]

Emission Unit	Heat Input (MMBtu/hr)	Natural Gas (MMscf/hr)	Hours of Operation (hrs/yr)
No. 2 Power Boiler	198.00	1.93E-01	8,760

1. Maximum hourly fuel consumption of natural gas, fuel oil, and propane is listed if unit fires particular fuel. Maximum fuel consumption is based on the heating value of each fuel.

Table B-21. No. 2 Power Boiler (B002) Maximum Potential Hazardous Air Pollutant and Toxic Air Pollutant Emissions - After Project

	Pollutant Classifications		Emission Factors	Potential Emissions	
	Georgia TAP	HAP	Natural Gas[1]	Natural Gas	
Pollutant	(Yes/No)	(Yes/No)	(lb/MMscf)	(lb/hr)	(tpy)
1,1,1-Trichloroethane [methyl chloroform]	Yes	Yes	-	-	-
1,2,3,4,6,7,8,9-Octachlorodibenzodioxin [OCDD]	Yes	Yes	-	-	-
1,2-Dibromoethane [ethylene dibromide]	No	Yes	-	-	-
1,2-Dichloroethane [ethylene dichloride]	Yes	Yes	-	-	-
2,4-Dinitrotoluene	Yes	Yes	-	-	-
2-Chloroacetophenone	Yes	Yes	-	-	-
2-Methyl naphthalene (POM)	Yes	Yes	2.40E-05	4.64E-06	2.03E-05
3-Methylchloranthrene (POM)	Yes	Yes	1.80E-06	3.48E-07	1.52E-06
5-Methyl chrysene (POM)	No	Yes	-	-	-
7,12-Dimethylbenz(a)anthracene (POM)	Yes	Yes	1.60E-05	3.09E-06	1.36E-05
Acenaphthene (POM)	No	Yes	1.80E-06	3.48E-07	1.52E-06
Acenaphthylene (POM)	No	Yes	1.80E-06	3.48E-07	1.52E-06
Acetaldehyde	Yes	Yes	-	-	-
Acetophenone	Yes	Yes	-	-	-
Acrolein	Yes	Yes	-	-	-
Anthracene (POM)	Yes	Yes	2.40E-06	4.64E-07	2.03E-06
Antimony	Yes	Yes	-	-	-
Arsenic	Yes	Yes	2.00E-04	3.87E-05	1.69E-04
Barium	Yes	No	4.40E-03	8.51E-04	3.73E-03
Benzene	Yes	Yes	2.10E-03	4.06E-04	1.78E-03
Benzo(a)anthracene (POM)	Yes	Yes	1.80E-06	3.48E-07	1.52E-06
Benzo(a)pyrene (POM)	Yes	Yes	1.20E-06	2.32E-07	1.02E-06
Benzo(b)fluoranthene (POM)	Yes	Yes	1.80E-06	3.48E-07	1.52E-06
Benzo(b,k)fluoranthene (POM)	Yes	Yes	-	-	-
Benzo(g,h,i)perylene (POM)	No	Yes	1.20E-06	2.32E-07	1.02E-06
Benzo(k)fluoranthene (POM)	Yes	Yes	1.80E-06	3.48E-07	1.52E-06
Benzyl chloride	Yes	Yes	-	-	-
Beryllium	Yes	Yes	1.20E-05	2.32E-06	1.02E-05
Biphenyl	Yes	Yes	-	-	-
Bis (2-ethylhexyl) phthalate	Yes	Yes	-	-	-
Bromoform	Yes	Yes	-	-	-
Bromomethane [methyl bromide]	Yes	Yes	-	-	-
Butane	Yes	No	2.10E+00	4.06E-01	1.78E+00
Cadmium	Yes	Yes	1.10E-03	2.13E-04	9.32E-04
Carbon disulfide	Yes	Yes	-	-	-
Chloride	Yes	Yes	-	-	-
Chlorobenzene	Yes	Yes	-	-	-
Chloroform	Yes	Yes	-	-	-
Chloromethane [methyl chloride]	Yes	Yes	-	-	-
Chromium	Yes	Yes	1.40E-03	2.71E-04	1.19E-03
Chromium VI	Yes	Yes	-	-	-
Cobalt	Yes	Yes	8.40E-05	1.62E-05	7.11E-05
Copper	Yes	No	8.50E-04	1.64E-04	7.20E-04
Cumene	Yes	Yes	-	-	-
Cyanide	Yes	Yes	-	-	-
Dibenzo(a,h)anthracene (POM)	Yes	Yes	1.20E-06	2.32E-07	1.02E-06
Dichlorobenzene	Yes	Yes	1.20E-03	2.32E-04	1.02E-03
Methylene chloride [dichloromethane]	Yes	Yes	-	-	-
Dimethyl sulfate	Yes	Yes	-	-	-
Ethane	Yes	No	3.10E+00	5.99E-01	2.63E+00
Ethyl chloride [chloroethane]	Yes	Yes	-	-	-
Ethylbenzene	Yes	Yes	-	-	-
Fluoranthene (POM)	No	Yes	3.00E-06	5.80E-07	2.54E-06
Fluorene (POM)	No	Yes	2.80E-06	5.41E-07	2.37E-06
Fluoride	Yes	No	-	-	-
Formaldehyde	Yes	Yes	7.50E-02	1.45E-02	6.35E-02
Hydrogen chloride	Yes	Yes	-	-	-
Hydrogen fluoride [hydrofluoric acid]	Yes	Yes	-	-	-
Indeno(1,2,3-c,d)pyrene (POM)	Yes	Yes	1.80E-06	3.48E-07	1.52E-06
Isophorone	Yes	Yes	-	-	-
Lead	Yes	Yes	5.00E-05	9.67E-06	4.23E-05
Magnesium	No	No	-	-	-
Manganese	Yes	Yes	3.80E-04	7.35E-05	3.22E-04
Mercury	Yes	Yes	2.60E-04	5.03E-05	2.20E-04
Methyl ethyl ketone [2-butanone]	Yes	No	-	-	-
Methyl hydrazine	Yes	Yes	-	-	-
Methyl methacrylate	Yes	Yes	-	-	-
Methyl tert butyl ether [MTBE]	Yes	Yes	-	-	-
Molybdenum	Yes	No	1.10E-03	2.13E-04	9.32E-04
Naphthalene	Yes	Yes	6.10E-04	1.18E-04	5.17E-04
n-Hexane	Yes	Yes	1.80E+00	3.48E-01	1.52E+00
Nickel	Yes	Yes	2.10E-03	4.06E-04	1.78E-03
o-Xylene	Yes	Yes	-	-	-
Pentane	Yes	No	2.60E+00	5.03E-01	2.20E+00
Phenanthrene (POM)	Yes	Yes	1.70E-05	3.29E-06	1.44E-05
Phenol	Yes	Yes	-	-	-
Phosphorus	Yes	Yes	-	-	-
Propane	Yes	No	1.60E+00	3.09E-01	1.36E+00
Propionaldehyde [propanal]	Yes	Yes	-	-	-
Pyrene (POM)	Yes	Yes	5.00E-06	9.67E-07	4.23E-06
Selenium	Yes	Yes	2.40E-05	4.64E-06	2.03E-05
Styrene	Yes	Yes	-	-	-
Tetrachloroethylene [perchloroethylene]	Yes	Yes	-	-	-
Toluene	Yes	Yes	3.40E-03	6.57E-04	2.88E-03
Vanadium	Yes	No	2.30E-03	4.45E-04	1.95E-03
Vinyl acetate	Yes	Yes	-	-	-
Zinc	No	No	2.90E-02	5.61E-03	2.46E-02
Toxic Air Pollutant Total				**2.18**	**9.57**
Hazardous Air Pollutant Total				**0.37**	**1.60**
Maximum Hazardous Air Pollutant				**0.35**	**1.52**

1. Emission factors for natural gas firing taken from AP-42 Chapter 1.4, "Natural Gas Combustion," Tables 1.4-3 and 1.4-4 (July 1998).

APPENDIX C

BACT SUPPORTING INFORMATION

RBLC Summary Table
Cost Effectiveness Calculations
Selected Public Comments on Proposed Boiler MACT CO Limit

Table C-1. Biomass Boiler RBLC and Permit Review Summary

ID	State	Facility	Unit	Boiler Type	Heat Input Capacity (MMBtu/hr)	New or Modified?	Unit Operating?	Fuels Unit is Permitted to Combust	Permit Date	Primary RBLC Fuel	CO BACT Limit (lb/MMBtu)	CO BACT Limit (ppm)	CO Averaging Period	CO Control Option	CO Compliance Method	CO Confirmed w/Permit?	CO Notes	NO_X BACT Limit (lb/MMBtu)	NO_X Averaging Period	NO_X Control Option	NO_X Compliance Method	NO_X Confirmed w/Permit?	NO_X Notes	Utility or Industrial?
AL-0198	AL	SMURFIT-STONE-STEVENSON	BOILER, NO.2 WOOD RESIDUE		620			Wood, NCG, Fuel Oil	9/30/2002	WOOD WASTE														
AL-0223	AL	STEVENSON MILL	NO. 2 WOOD-FIRED BOILER		620			Biomass	7/14/2006	BIOMASS														
AR-0072	AR	DEL TIN FIBER LLC	HEAT ENERGY SYSTEM	Gassifier	291			Biomass	2/28/2003	WOOD WASTE	0.78			Good Combustion Practices				0.3		LNB, SNCR	Unknown			
AR-0083	AR	POTLATCH CORPORATION - OZAN UNIT	WOOD FIRED BOILER		175			Wood	7/26/2005	WOOD CHIPS	1.35			Good Combustion Practices				0.25		Good Combustion Practices				
CT-0156	CT	MONTVILLE POWER LLC	Unit 5 (43 MW biomass; 82 MW tangentially fired natur	Stoker	600	Modified		Clean wood, NG, ULSD	4/6/2010	Clean Wood	0.1		8-hour	Oxidation Catalyst	CEMS									Utility
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	BOILER	FB Gasification	523.1	New	Not Yet	Biomass, biodiesel	2008	WOOD	0.105	103.7	30-day	Good Combustion Practices	CEMS	Yes		0.075	30-day	SNCR	CEMS	Yes	70% control expected, LAER	Utility
CT-03	CT	WATERTOWN RENEWABLE POWER	BOILER	FB Gasification	436	New	Not Yet	Biomass, Natural Gas (startup)	Draft 2009	WOOD	0.1	107.15	8-hour	Good Combustion Practices	CEMS	Yes	permit engineer: Valerie Galo, 860-424-3	0.075	24-hour	SCR	CEMS	Yes	LAER, 70% control	Utility
FL-0034	FL	U.S. SUGAR CLEWISTON MILL AND REFINERY	BOILER, TRAVELING GRATE	Grate	633			Bagasse, No. 6 Fuel Oil	11/29/2000	BAGASSE	6.5			Good Combustion Practices				0.2		Good Combustion Practices				
FL-0248	FL	US SUGAR CORPORATION	BOILER, BAGASSE, NO. 4		633			Bagasse, No. 6 Fuel Oil	11/19/1999	BAGASSE	6.5			Good Combustion Practices				0.2		Good Combustion Practices				
FL-0257	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER	Unknown	936			Bagasse, Diesel	11/18/2003	BAGASSE	0.38		annual	Good Combustion Practices				0.14	30-day	SNCR	Unknown			
FL-0301	FL	CLEWISTON SUGAR MILL AND REFINERY	BOILER 7		738			Wood, Bagasse	12/6/2007	BAGASSE				Good Combustion Practices				0.31	3-hour	OFA, Good Combustion			25% annual capacity limit for wood	
FL-0318	FL	HIGHLANDS ETHANOL FACILITY	BIOMASS FUELED BOILER	BFB	198	New		Stillage cake, biomass, NG, ULSD, and biogas from anaerobic reactors. Backup burns biogas, NG, ULSD, or propane.	12/10/2009	Stillage and biomass.	0.1		30-day rolling	Good Combustion Practices	CEMS		19.8 lb/hr 30-day rolling average secondary limit							Industrial
GA-0097	GA	INTERSTATE PAPER	MULTIFUEL BOILER	BFB	300			Wood, Oil, Gas, TDF, Sludge, Peat, Turpentine, N(	12/30/2002	COMBINED	0.3		30-day	Good Combustion Practices				0.25	30-day	Fluidized Bed Design				
GA-0114	GA	INLAND PAPERBOARD AND PACKAGING, INC. - ROME	BOILER, SOLID FUEL		856			Bark, Sludge, TDF, Fuel Oil, NCG	10/13/2004	BARK		368		Staged Combustion			at 3% O2							
GA-0117	GA	TRI-GEN BIOPOWER	BOILER, MULTIFUEL	BFB	302.2			Wood, Sludge	5/24/2001	WOODWASTE AND PAPERMIL	0.3			Good Combustion Practices										
GA-02	GA	YELLOW PINE ENERGY COMPANY	BOILER	CFB	1,450	New	Not Yet	Biomass, TDF, Propane, Fuel Oil	9/8/2010	BIOMASS	0.149		30-day	Good Combustion Practices	CEMS	Yes (p. 7)	Case-by-case MACT	0.07	30-day	SNCR	CEMS	Yes (p. 7)		Utility
GA-04	GA	GREENWAY RENEWABLE POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	7/19/2008	BIOMASS			annual	Good Combustion Practices	CEMS	Yes (p. 3)	PSD Avoidance		Annual	SNCR	CEMS	Yes (p. 3)	PSD Avoidance	
GA-05	GA	PIEDMONT GREEN POWER, LLC	BOILER		719	New	Not Yet	Biomass, biodiesel	9/17/2008	BIOMASS			annual	Good Combustion Practices	CEMS	Yes	PSD Avoidance		Annual	SNCR	CEMS	Yes	PSD Avoidance	
GA-08	GA	BIOMASS GAS & ELECTRIC	Gasifier/Combustor w/HRSG	Gassifier	372	New	Not Yet	Biomass	5/20/2008	BIOMASS				Good Combustion Practices	Stack Test	Yes	PSD Avoidance		Annual	SCR	CEMS	Yes	NNSR Avoidance	
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BOILER	BFB	400	New	Not Yet	Biomass, Oil/Grease/Fat, Biodiesel, Chicken Litter	7/29/2008	BIOMASS	0.149		30-day	Oxidation Catalyst	CEMS	Yes (p. 7)	Case-by-case MACT			SNCR	CEMS	Yes (p. 6)	PSD Avoidance	Utility
GA-12	GA	OGLETHORPE POWER CORPORTATION	BFB Biomass Boiler	BFB	1,399	New	Not Yet	Woody biomass fuel blend, biodiesel, ULSD	12/22/2010	Woody biomass	0.08		30-day averag	Good Combustion Practices	CEMS									Utility
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB BOILER	CFB	996	New		Coal, Petcoke, Biomass, TDF	8/16/2006	COAL	0.154	400	24-hour	Good Combustion Practices	CEMS	Yes (p. 56)	ppm is at 7% O2 30-day limit	0.15	30-day	SNCR	CEMS	Yes (p. 56)	Based on lb/hr limit	Industrial
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	FIBER FIRED BOILERS AND GERM DRYERS/COOL	Unknown	200	New	Not Yet	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	CORN FIBER	0.17	100	30-day	Good Combustion Practices	CEMS	7), p 52 of detern	Excludes SU/SD, mal; case-by-case MA(	0.129	30-day	SCR	CEMS	Yes (p. 7)	Excludes SU/SD and malfunctions	Industrial
KY-0085	KY	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	BOILER, BARK		631			Wood, Sludge, Oil, Gas, NCG	2/27/2002	BARK								0.4		Good Combustion Practices				
LA-0122	LA	INTERNATIONAL PAPER - MANSFIELD MILL	POWER BOILERS 1 & 2		760			Wood Waste, Coal, Oil, Gas, Recycle Fiber	8/14/2001	COMBINED				Restriction on Inputs			Equation used to calculate limit dependin	0.7		Good Combustion Practices			Non-coal solid fuel limit	
LA-0125	LA	WEYERHAEUSER COMPANY, DODSON SAWMILL	WOOD FIRED BOILER (#017)	Unknown	233	Modified		Wood/Bark	10/29/2007	WOOD	0.82			Good Combustion Practices				0.21		Good Combustion Practices				
LA-0126	LA	JOYCE MILL, WEST FRASER	KIPPER BOILERS NO. 1 AND NO. 2 (EACH)		58.3			Biomass	4/24/2002	WOOD WASTE	1.81			Good Combustion Practices										
LA-0126	LA	JOYCE MILL, WEST FRASER	MCBURNEY BOILER NO.4		154.2			Biomass	4/24/2002	WOOD WASTE	1.81			Good Combustion Practices										
LA-0174	LA	GEORGIA-PACIFIC - PORT HUDSON	COMBINATION BOILER NO. 1		459.5	Modified	Yes	Wood, Natural Gas	1/25/2002	COMBINED	2.45			Good Combustion Practices			1125.4 lb/hr, 1313.2 tpy	0.3		Good Combustion Practices			Biomass Limit	
LA-0178	LA	DERIDDER PAPER MILL, BOISE CASCADE	WOOD-FIRED BOILER		454.29			Wood, Gas, NCG	11/14/2003	BARK	0.33		annual	Good Combustion Practices										
LA-0188	LA	BOGALUSA MILL, INLAND PAPERBOARD	NO. 12 HOGGED FUEL BOILER	Has Grate	787.5			Wood, OCC Rejects, Fuel Oil	11/23/2004	BARK	0.6		annual	OFA, Good Combustion Practices				0.45		OFA, LNB for gas-fired under grate air heater system				
LA-0190	LA	GEORGIA-PACIFIC - PORT HUDSON	BOILER 6	CFB	Unknown	Modified	Yes	Wood, Sludge, Petcoke, Coal, Gas, Paper, Bagasse	8/22/2005	COMBINED					None			0.7		Good Combustion Practices	CEMS	es (p. 194 of pd	NSPS Limit	
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Hogged Fuel BOILER 2 (EQT 11)	Unknown	940	Modified	Yes	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	HOGGED FUEL								0.15	30-day	SNCR	CEMS	p. 115 [#158] of pdf)		
LA-0218	LA	FLORIEN PLYWOOD PLANT, BOISE BUILDING SOLUTIONS	HOGGED FUEL FIRED BOILER (EQT 1)	Unknown	225	Modified	Yes	Wood, Natural Gas	7/18/2007	WOOD	0.6		1-hour	OFA, Good Combustion Practices	Stack Test	Yes (p. 47 of pdf)	Subject to performance test	0.22		Good Combustion Practices	CEMS	Yes (p. 47)		
MA-02a	MA	RUSSELL BIOMASS	BIOMASS BOILER	BFB	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.075		Unknown	Good Combustion Practices	CEMS	Yes (p. 46)	Ox cat too costly ($40K/ton)	0.06	Unknown	SCR	CEMS	Yes (p. 46)	LAER	Utility
MA-02b	MA	RUSSELL BIOMASS	BIOMASS BOILER	Stoker	740	New	Not Yet	Clean Wood	12/30/2008	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS	Yes (p. 46)	Part of RSCR, ~70% reduction	0.06	Unknown	RSCR	CEMS	Yes (p. 46)	LAER	Utility
MA-03	MA	PIONEER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	663	New	Not Yet	Wood	Application	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS	Yes (p. B-20)	permit engineer: Courtney Danneker. Vol	0.06	Unknown	SCR	CEMS	Yes (p. B-20)	Cold-side SCR, LAER	Utility
MA-05	MA	PALMER RENEWABLE ENERGY	BIOMASS BOILER	Stoker	38 MW	New	Not Yet	Biomass	Application	WOOD	0.075		Unknown	Oxidation Catalyst	CEMS		Part of RSCR. Courtney Danneker - getti	0.06	Unknown	RSCR	CEMS		LAER	Utility
ME-0021	ME	S.D. WARREN CO. - SKOWHEGAN, ME	POWER BOILER, #2	Unknown	1300	Modified	Yes	Wood, Sludge, Oil, TDF, Paper, NCG	11/27/2001	WOOD WASTE	0.4		30-day	Good Combustion Practices	CEMS	Yes (p. 16)		0.2	30-day	SNCR	CEMS	Yes (p. 16)		
ME-0026	ME	WHEELABRATOR SHERMAN ENERGY COMPANY	BOILER # 1		315			Wood, Fuel Oil	4/9/1999	WOOD	0.45			Good Combustion Practices				0.25	30-day	Good Combustion Practices				
ME-01	ME	BORALAX STRATTON ENERGY, INC.	WOOD/OIL-FIRED BOILER	FB	672	Modified	Yes	Wood, Oil	1/4/2005	COMBINED	0.6		24-hour	Good Combustion Practices	CEMS	Yes (p. 4)		0.075	Quarterly	Ecotube, RSCR	CEMS	Yes (p. 4)	Voluntary limit to qualify for RECs	
MI-0258	MI	TES FILER CITY STATION	BOILER, SPREADER STOKER, 2 EACH	Stoker	384	Modified		Coal, Wood, TDF	4/5/2001	COAL/TIRES/WOOD	0.3		8-hour	Good Combustion Practices	CEMS	Yes (p. 25)		0.60	30-day	SCR	CEMS	Yes (p. 25)	NSPS Limit	
MI-0285	MI	GRAYLING GENERATING STATION	BOILER, MIXED FUEL (WOOD & TIRES)	Stoker	523	Modified	Yes	Wood, TDF	9/18/2001	WOOD AND TIRES	0.40	464	24-hour	Good Combustion Practices	CEMS	Yes (p. 18)	15% O2	0.15	30-day	SNCR	CEMS	Yes (p. 18)	106 ppm at 15% O2	
MI-0382	MI	WYANDOTTE DEPARTMENT OF MUNICIPAL SERVICES	BOILER NO. 8	CFB	369			Coal, Wood, Gas, TDF	5/26/2005	TDF														
MI-0386	MI	RIPLEY HEATING PLANT	CFB BOILER	CFB	205	New	Not Yet	Wood, Coal, Gas	5/12/2008	WOOD & COAL	0.17		3-hour	Good Combustion Practices	Stack Test	Yes (p. 6)		0.1	30-day	SNCR	CEMS	Yes (p. 8)		Institutional
MN-0046	MN	DISTRICT ENERGY ST. PAUL, INC	BOILER	Unknown	550	Unknown		Wood, Gas	11/15/2001	WOOD	0.3			Good Combustion Practices			Biomass limit	0.15		SNCR	Unknown		Biomass limit	
MN-0057	MN	FIBROMINN BIOMASS POWER PLANT	BOILER, MULTIFUEL	Stoker	792	New	Yes	Manure, Biomass, Natural Gas, Propane	10/23/2002	MANURE	0.24		24-hour	Good Combustion Practices	CEMS	Yes (p. A8)		0.16	30-day	SNCR	CEMS	Yes (p. A8)	Includes SU/SD and malfunctions	
MN-0058	MN	VIRGINIA DEPARTMENT OF PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230			Wood	6/30/2005	WOOD	0.3		4-hour	Good Combustion Practices				0.15	30-day	SNCR	Unknown			
MN-0059	MN	HIBBING PUBLIC UTILITIES	BOILER, WOOD FIRED	Stoker	230	New		Wood	6/30/2005	WOOD	0.3		4-hour	Good Combustion Practices				0.15	30-day	SNCR	Unknown			
MN-0074	MN	KODA ENERGY	BIOMASS BOILER 1	Suspension	308			Natural Gas, Biomass	8/23/2007	BIOMASS	0.43		30-day	Good Combustion Practices				0.25	30-day	SNCR	Unknown		Biomass Limit	
MN-0078	MN	SAPPI FINE PAPER PLC, CLOQUET	Boiler		430	Modified	Yes	Wood, Natural gas	10/28/2009	Wood														
MS-0075	MS	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	COMBINATION BOILER	Stoker	917.4			Wood, Sludge, TDF, Fuel Oil	7/9/2003	SCRAP WOOD	1.38			Good Combustion Practices				0.31000654		LNB, OFA, Stoker Controls			Based on lb/hr limit	
NC-0092	NC	RIEGELWOOD MILL, INTERNATIONAL PAPER CO.	BOILER, POWER #5	Unknown	600	Modified	Yes	Coal, Wood, Sludge, Fuel Oil	5/10/2001	WOODWASTE	0.5		3-hour	Good Combustion Practices	Stack test	Yes (p. 10)	Biomass limit	0.35	3-hour	OFA	Stack Test	Yes (p. 10)	Biomass Limit	
ND-0022	ND	NORTHERN SUN, ARCHER DANIELS MIDLAND	WOOD/HULL FIRED BOILER	Stoker				Wood, Hulls, RR Ties	5/1/2006	BIOMASS	0.63							0.2	30-day	Good Combustion Practices			SNCR $ ineffective	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	COGEN BOILERS (2)	CFB	768	New		Coal, Biomass, Petcoke, TDF	2/18/2009	COMBINED	0.1		30-day	Good Combustion Practices	CEMS	Yes (p. A-3)	Also 150 lb/hr 3-hr avg limit	0.07	30-day	SNCR	CEMS	Yes (p. A-3)	Excludes cold SU	Industrial
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	BOILER, WOOD FIRED CFB, UNIT #5	CFB	720	New	Yes	Wood, Coal	10/25/2004	BIOMASS	0.1		24-hour	CFB Design	CEMS	Yes (p. 15)	Wood Limit for about 50% load	0.075	24-hour	SNCR	CEMS	Yes (p. 29)	Wood limit, not a BACT limit	Utility
NH-0015	NH	CONCORD STEAM CORPORATION	BOILER #1	Stoker	305	New	No	Biomass, Natural Gas (startup)	2/27/2009	BIOMASS								0.065	30-day	SCR	CEMS			
NH-0016	NH	CLEAN POWER BERLIN, LLC	BOILER 1	Gassifier	29 MW	New	No	Wood Chips, Natural gas	9/25/2009	WOOD								0.065	30-day	SCR	CEMS			
NH-0018	NH	BERLIN BIOPOWER	EU01 Boiler #1	BFB	1,013	New		Whole tree wood chips, low grade clean wood, No.	7/26/2010	WOOD	0.075		Calendar Day	BFB Boiler Design and FGR	CEMS		Secondary limit of 307.3 tpy including startup and shutdown							Utility
NH-02	NH	BRIDGEWATER POWER COMPANY	WOOD/OIL-FIRED BOILER	Stoker	250	Modified	Yes	Wood, Oil	9/12/2007	COMBINED	0.228		annual	Good Combustion Practices	CEMS	Yes	PSD Avoidance limit of 250 tpy	0.075	Quarterly	SNCR, RSCR	CEMS	Yes (p. 9)	Voluntary limit for RECs	
NH-03	NH	WHITEFIELD POWER	BOILER	Stoker	220	Modified	Yes	Wood	2004	BIOMASS	0.26		annual	Good Combustion Practices	CEMS	Yes	PSD Avoidance limit of 250 tpy	0.075	Quarterly	RSCR	CEMS	Yes	Voluntary limit for RECs	
NH-04	NH	LAIDLAW BERLIN BIOPOWER	BOILER	BFB		Modified	No	Biomass	Pre-Application	BIOMASS										SCR				
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BOILER	BFB	483	New	No	Biomass	Draft, 2007	BIOMASS	0.105		30-day	Good Combustion Practices	CEMS	Yes (p. 11)	Based on lb/hr limit	0.109109731	30-day	SNCR	CEMS	Yes (p. 7)	Based on lb/hr limit	Utility
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	BOILERS (2)	Grate	180	Modified	Yes	Wood, Tires, Gas	8/12/2008	WOOD, TIRES, NATURAL GAS	0.1		annual	Good Combustion Practices	Fuel Records	Yes (p. 32)	Not BACT; based on lb/hr limit	0.24		Restriction on usage of natural gas	Fuel Records	Yes (p. 20, 25)	PSD Avoidance	Utility
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	WOOD FIRED BOILERS (7), EACH	Stoker	318	Modified	Yes	Wood	4/4/2006	WOOD	0.1		30-day	Oxidation Catalyst	CEMS	Yes (p. 114)	50% efficiency	0.087987421	30-day	SCR	CEMS	Yes (p. 112)	Based on lb/hr limit; 80% efficiency	Utility
OK-0084	OK	WEYERHAEUSER - VALLIANT MILL	POWER BOILER 2		N/A			Mixed Fuels	6/8/1999	COMBINED		250		Good Combustion Practices			at 8% O2	0.15		FGR				
PA-0272	PA	CLARION BOARDS, INC	EPI ENERGY UNIT; FIBER DRYING SYSTEM		141	Modified		Wood	9/9/2009	Wood	0.30		12-month rolling 18	Good Combustion Practices	CEMS									Industrial
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 1					Bagasse	10/10/2003	BAGASSE										Good Combustion Practices			48 lb/hr	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 1					Bagasse	10/10/2003	BAGASSE										Good Combustion Practices			32.4 lb/hr	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 1-2: CASE 2					Bagasse	10/10/2003	BAGASSE										Good Combustion Practices			33.6 lb/hr	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 3-4: CASE 2					Bagasse	10/10/2003	BAGASSE										Good Combustion Practices			22.68 lb/hr	
TX-0461	TX	WR COWLEY SUGAR HOUSE	BOILER 6					Bagasse	10/10/2003	BAGASSE										Good Combustion Practices			135 lb/hr	
TX-0485	TX	INLAND PAPERBOARD AND PACKAGING, INC. - ORANGE	BARK BOILER		471.4285714			Wood, OCC, Gas, NCG	10/5/2004	WOOD WASTES, OCC, BARK, G	0.4		30-day	Good Combustion Practices				0.220606061		SNCR	Unknown		LAER; 104 lb/hr	
TX-0553	TX	LINDALE RENEWABLE ENERGY	WOOD-FIRED BOILER	Stoker		New		Biomass, Biodiesel	1/8/2010	Biomass	0.31		Rolling 30-day	Good Combustion Practices	CEMS		CO was surrogate for organic HAP							Utility
TX-0555	TX	ASPEN POWER - LUFKIN GENERATING PLANT	WOOD-FIRED BOILER	Stoker	693	New	Not Yet	Untreated Wood Waste	10/26/2009	Untreated wood waste	0.075		Rolling 30-day	Oxidation Catalyst	CEMS			0.075	Rolling 30-da	SCR	CEMS			Utility
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BOILER	BFB	1374	New		Biomass, Gas	3/1/2007	BIOMASS	0.15		30-day	Good Combustion Practices	CEMS	Yes		0.1	30-day	SNCR	CEMS	Yes		Utility
VA-0268	VA	THERMAL VENTURES	BOILER, STEAM		120			Wood, Coal	2/15/2002	WOOD	0.44			Good Combustion Practices				0.4		Good Combustion Practices				
VA-0298	VA	INTERNATIONAL BIOFUELS, INC	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING		77			Wood	12/13/2005	WOOD/WOODPASTE	0.19			Thermal Oxidizer				0.22		Good Combustion Practices				
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY (DOMINION)	BOILERS (3)	Stoker	373.3	New	Yes	Biomass	1/1/2003	BIOMASS	0.35		30-day	Good Combustion Practices	CEMS	Yes (p. 9 [B.2])		0.1	30-day	SNCR	CEMS	Yes (p. 9)	Minimum of 50% control required	
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	MULTIFUEL BOILER	Stoker	750	Modified	Yes	Wood, Natural Gas, Oil	4/21/2008	COMBINED		1500	1-hour	Good Combustion Practices	CO Monitor	Yes (p. 16)		0.075	Quarterly	RSCR	CEMS	Yes (p. 15)	Voluntary limit for RECs.	
VT-02	VT	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	BOILER																					
WA-0298	WA	ABERDEEN DIVISION - SIERRA PACIFIC	HOG FUEL BOILER	Stoker	310	New		Wood, Natural Gas (Startup only)	10/17/2002	WASTE WOOD	0.35	300	24-hour	Good Combustion Practices	CEMS	Yes (p. 15)		0.15	24-hour	SNCR	CEMS	Yes (p. 15)	0.1 lb/MMBtu, annual avg.	
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	WOOD-FIRED COGENERATION UNIT	Stoker	430	New		Biomass	12/12/2005	BARK & WASTE WOOD	0.35		1-hour	Good Combustion Practices	CEMS	Yes (p. 10)		0.13	24-hour	SNCR	CEMS	Yes (p. 9)	0.1 lb/MMBtu, annual avg.	
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER PLANT	WOOD WASTE-FIRED BOILER	Stoker	403	New		Wood	2/11/2005	WOOD WASTE	0.35		24-hour	Good Combustion Practices	CEMS	Yes (p. 5)		0.12	24-hour	SNCR	CEMS	Yes (p. 5)		
WA-0335	WA	SIMPSON TACOMA KRAFT COMPANY, LLC	POWER BOILER 7	Unknown	595	Modified	Yes	Wood, OCC, Sludge, No. 6 Fuel Oil	5/22/2007	WOOD WASTE	0.35		30-day	OFA	CEMS	Yes (p. 6)		0.2	30-day	OFA, Good Combustion	CEMS	Yes (p. 5)	Due to salt in wood, no SNCR	
WA-0336	WA	GRAYS HARBOR PAPER LP	RILEY BOILER	Riley VO	379			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE														
WA-0336	WA	GRAYS HARBOR PAPER LP	BOILER 6	Dutch Oven	227			Wood, No. 6 Fuel Oil	11/17/2006	WOOD WASTE														
WA-0337	WA	BOISE WHITE PAPER LLC	HOG FUEL BOILER		343			Wood Waste, Gas	2/1/2006	WOOD/BARK		500	annual	OFA, Good Combustion Practices				0.3	30-day	OFA, Good Combustion Practices			Limit was raised per vendor lack of guarantee	

* Note that entries with a six character ID are from the U.S EPA RBLC Database. Entries with a four character ID are from permit file reviews.

Table C-2. General Cost Analysis Supporting Information

Parameter	Value	Units	Basis/Notes
Maximum Boiler Capacity	620	MMBtu/hr	Designed value per Larson Engineering documents
Maximium Annual Operation	8,760	hr/yr	Assume unrestricted operation
Operating Labor Cost	29.26	$/hr	Actual GPI Cost in December 2010
Maintenance Labor Cost	30.38	$/hr	Actual GPI Cost in December 2010
Natural Gas Cost	5.31	$/MMBtu	Actual GPI cost in December 2010; conservatively used the lower cost for natural gas without hedge.
Electricity Cost	0.058	$/kW-hr	Actual GPI Cost in December 2010

Table C-3. Oxidation Catalyst (with Reheat) Cost Analysis Supporting Information

Parameter	Value	Units	Reference
Maximum Boiler Capacity	620	MMBtu/hr	1
Uncontrolled CO Emissions	0.15	lb/MMBtu	1
Controlled CO Emissions	0.075	lb/MMBtu	2
Removal Efficiency	50%	%	3
Pollutant Removed	204	tpy	4
Inlet Airflow - Maximum	320,000	acfm	1
Inlet Temperature	300	° F	1
Volume of Catalyst	387	ft^3	5
Pressure Drop Across the Oxidation Catalyst	10.0	inches of H_2O	6
Electricity Usage	430.4	kW-hr	5
Natural Gas Consumption for Gas Reheating	48.6	MMBtu/hr	7
Catalyst Life	3	year	6
Catalyst Cost, Initial	387.50	$\$/ft^3$	6
Catalyst Cost, Replacement	401.50	$\$/ft^3$	6
Oxidation Catalyst Equipment Life	10	years	8
Interest Rate	7.0	%	8

1. Design value per Larson Engineering and boiler vendor (Andritz).
2. Expected control from oxidation catalyst based on RBLC results and varibility inherent with the load and fuel for the proposed boiler.
3. Removal efficiency (%) = 100% - (Controlled outlet emissions) / (Uncontrolled inlet emissions)
4. Pollutant removed (tpy) = (Uncontrolled inlet emissions - Controlled outlet emissions, lb/MMBtu) × (Maximum boiler capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
5. Based on the vendor quote provided to the Oglethorpe Power Company's Warren County Biomass Energy Facility for the permit application submitted to EPD on October 14, 2009, to construct a 1,282 MMBtu/hr BFB biomass boiler; scaled to the size of the proposed GPI No. 3 Biomass Boiler.
6. Vendor quote provided to the Oglethorpe Power Company's Warren County Biomass Energy Facility (http://www.gaepd.org/air/airpermit/downloads/permits/30100016/psd19121/application19121.pdf) for the BFB boiler; assumed similar design.
7. Assumes exhaust stream temperature needs to be heated to 500°F. Calculated based on natural gas heating value of 1,020 Btu/scf, and Energy required = (Mass of exhaust stream) × (Specific heat capacity of exhuast stream) × (Change in temperature).
8. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.

Table C-4. Cost Analysis for Oxidation Catalyst with Reheat

Capital Cost	**CO + Reheat**	**OAQPS Notation[1]**
Purchased Equipment Costs		
Total Equipment Cost[2]	3,457,859	A
Instrumentation	345,786	0.10 × A
Sales Tax	103,736	0.03 × A
Freight	172,893	0.05 × A
Total Purchased Equipment Costs	*4,080,274*	*B = 1.18 × A*
Direct Installation Costs		
Foundations and Supports	326,422	0.08 × B
Handling and Erection	571,238	0.14 × B
Electrical	163,211	0.04 × B
Piping	81,605	0.02 × B
Insulation	40,803	0.01 × B
Painting	40,803	0.01 × B
Total Direct Installation Costs	*1,224,082*	*C = 0.30 × B*
Indirect Installation Costs		
Engineering	408,027	0.10 × B
Construction and Field Expense	204,014	0.05 × B
Contractor Fees	408,027	0.10 × B
Start-up	81,605	0.02 × B
Performance Test	40,803	0.01 × B
Process Contingencies	122,408	0.03 × B
Owners Cost[3]	204,014	0.05 × B
Total Indirect Installation Costs	*1,468,899*	*D = 0.36 × B*
Project Contingency[3]	1,354,651	E = 0.20 × (B + C + D)
Total Plant Cost	8,127,906	F = B + C + D + E
Allowance for Funds During Construction[3]	568,953	G = 0.07 × F
Total Capital Investment	**8,696,860**	**TCI = (F + G)**

Operating Cost	**CO + Reheat**	**OAQPS Notation**
Direct Annual Costs		
Operating Labor (0.5 hr, per 8-hr shift)	16,020	H
Supervisory Labor	2,403	I = 0.15 × H
Maintenance Labor (0.5 hr, per 8-hr shift)	16,633	J
Maintenance Materials	16,633	K = J
Electricity	218,688	L
Catalyst Replacement[4]	155,339	M
Natural Gas for Gas Reheating	2,259,891	N
Total Direct Annual Costs	*2,685,607*	*DAC = H + I + J + K + L + M + N*
Indirect Annual Costs		
Overhead	31,013	O = 0.60 × (H + I + J + K)
Administrative Charges	173,937	P = 0.02 × TCI
Property Tax	86,969	Q = 0.01 × TCI
Insurance	86,969	R = 0.01 × TCI
Capital Recovery[5]	1,238,237	S
Total Indirect Annual Costs	*1,617,125*	*IDAC = O + P + Q + R + S*
Total Annual Cost	**4,302,732**	*TAC = DAC + IDAC*
Pollutant Removed (tpy)	204	
Cost per ton of Pollutant Removed	**21,126**	*$/ton = TAC / Pollutant Removed*

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 3.2, Chapter 2.

2. Direct Capital Costs are based on the vendor quote provided to the Oglethorpe Power Company's Warren County Biomass Energy Facility (http://www.gaepd.org/air/airpermit/downloads/permits/30100016/psd19121/application19121.pdf) and scaled to the size of the proposed GPI No. 3 Biomass Boiler.

3. Per Warren County Biomasss Energy Facility application, costs are not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience, and thus costs are included or adjusted. Assumed same approach.

4. 100% of catalyst is replaced based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.

5. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Proposed Boiler MACT – Extracted Sections from Public Comments Submitted Related to Establishment of CO Limits for Biomass Boilers

Babcock and Wilcox Power Generation Group, EPA-HQ-OAR-2002-0058-2722.1[1].pdf, letter from Richard L. Killion, President & COO, August 6, 2010:

<u>Infeasibility of CO Limits [page 4]</u>
While proposed CO limits may be achievable for certain source/fuel categories under defined steady state operating conditions, offering commercial guarantees on a 30-day rolling average basis which include periods of start-up, shutdown, and malfunction (SSM) are not feasible.

Specifically, B&W is not aware of combustion or AQCS technology (or a combination of both) that would allow an equipment supplier, such as ourselves, to offer commercial CO performance guarantees over a wide range of operating conditions, including, but not limited to, periods of SSM for the following source categories:

- New Biomass Fluidized Bed Boilers (40 ppm)
- New Coal Stoker Boilers (7 ppm)
- New and Existing Coal Fluidized Bed Boilers (30 ppm and 40 ppm, respectively)
- New and Existing Liquid Fuels Boilers (1ppm)
- New and Existing Gas (and other process gases) Boilers (1 ppm)

B&W is especially concerned that the proposed CO limits will make it problematic to achieve compliance with the above limits given the wide variability in fuel properties (particularly biomass), boiler design capacity, and plant specific operating conditions.

<u>Limits are too low if including SSM variability [pages 5-6]</u>
If the emissions limits are to include SSM, then the units that are setting the limits should be continuously monitored for CO and PM to determine the impact to the stack test average. Of the six units that were continuously monitored for CO, the CO was considerably higher for units that had SSM conditions included in their data sets…. Table 1 illustrates the impact of SSM on CO readings.

Table 1: EPA data related to continuous monitoring of CO

BIOMASS STOKER AR DOMTAR - PB1	Average of Continuous Data	2179.33 ppm	
	Average of Stack Test Data	120.70 ppm	
	Percent Difference	**1706%**	
BIOMASS DUTCH OVEN TX DIBOLL TEMPLE INLAND - PB44	Average of Continuous Data	727.73 ppm	
	Average of Stack Test Data	69.3 ppm	
	Percent Difference	**950%**	
PULVERIZED COAL VA PHILLIP MRRIS PARK 500 - B3	Average of Continuous Data	34.13 ppm	
	Average of Stack Test Data	12.70 ppm	
	Percent Difference	**169%**	
NATURAL GAS WA BOEING RENTON - BOIL04	Average of Continuous Data	15.15 ppm	
	Average of Stack Test Data	11.97 ppm	NO SSM
	Percent Difference	**27%**	
COAL STOKER WV DUPONT WASHINGTON WORKS - P05	Average of Continuous Data	26.14 ppm	
	Average of Stack Test Data	16.31 ppm	NO SSM
	Percent Difference	**60%**	

The data tabulated illustrates the potential impact of including SSM conditions for CO on solid fuels only. … There needs to be an exemption in the rule for each SSM period associated with commissioning of new units and with a restart following a major maintenance overhaul of the unit. Emissions will be higher during these periods while equipment and controls are brought into service for the first time. This is part of new/overhauled equipment commissioning and needs to be recognized by the compliance limits.

Biomass Diversity Must be Reflected in Limits [page 7]
As proposed, the fuel subcategories do into take into account the very wide range of physical properties of the different fuels in a single subcategory. This is especially pronounced with biomass which can range from whole tree chips to grasses, agricultural waste, and animal manure. We would recommend either greater segregation in subcategories or limits that better reflect this diversity in fuel properties.

CO Limit Based on Blended Fuel [pages 7-8]
Table 2 summarizes the best performing units that set proposed emission limits for new units that have significant dilution fuel blends.

Table 2: Best performing units that reported data while firing significant dilution fuel blends

Pollutant	Fuel Blend 1	Fuel Blend 2	Fuel Blend 3	Fuel Blend 4	Fuel Blend 5
Coal - Mercury	100% Coal	50% Coal / 50% Biomass	25% Coal / 75% Biomass		
Pulverized Coal - Dioxin/Furan	59% Coal / 34% Biomass / 7% NG				
Biomass - Particulate Matter	74% Biomass / 5% No. 6 Oil / 21% NG	60% Biomass / 40% No. 6 Oil	83% Biomass / 9% No. 6 Oil / 8% TDF	86% Biomass / 14% NG	88% Biomass / 12% NG
Biomass FB – CO & Dioxin/Furan	64% Biomass / 19% Sludge / 17% NG	71% Biomass / 21% Sludge / 2% NG	73% Biomass / 23% Sludge / 4% NG	76% Biomass / 21% Sludge / 3% NG	
Biomass Dutch Oven – Dioxin/Furan	31% Biomass / 69% NG				
Biomass Fuel Cell - CO	72% Biomass / 28% Propane	67% Biomass / 33% Propane			

Inability of Single Boiler to Meet the Proposed Limits [page 8]
To establish the emission limit for new boilers, the EPA selected the single best performer in each emission category independent of other emissions. While it may be possible to achieve a single emission limit, there is a low probability that all emissions limits can be achieved simultaneously be a single boiler because of the very nature of the pollutant interactions. Control of a single pollutant cannot be efficiently achieved without considering all of the other emissions at the same time.

Energy and Environmental Impacts of Controlling CO [page 10]
Implementation of the industrial MACT would not necessarily decrease fuel usage. One of the means to control CO is to increase excess air to the unit which would decrease unit efficiency and increase fuel usage. … The CO limits in the proposed MACT will require burners and air systems that increase NO_X. The relationship between lower CO and higher NO_X has been well established. This will require additional equipment to address NO_X.

Metso Power Generation Group, EPA-HQ-OAR-2002-0058-2388.1[1].pdf, letter from Kerry R. Flick, General Manager - Technology, August 12, 2010:

Limits do not account for Biomass Variability and Pollutant Co-Dependence [page 2]:
In Metso's opinion, the data used to develop the proposed emissions limits does not have the required depth, and individual pollutants have been set without considering pollutant co-dependence. … we also suggest that due to the variability in biomass (from a fuel/ash composition, time of harvesting and regional sourcing standpoint), that consideration be given to making a change to the ruling of the Clean Air Act (CAA) that sets the MACT floor for new units based solely on the "top performer" for each individual pollutant. Suggested changes for the MACT floor settings for a new biomass renewable energy plant should be based upon the complete set of measured emissions from only the top "operating" performer in each regional location and for each given biomass classification as defined below, regardless of the combustion technology employed:

1) Regional location (i.e., Northeast; Midwest; Southeast; Southwest; Northwest; West; and Coastal)
2) Classification of biomass
    a. Agricultural (crops, dedicated energy crops, animal wastes, and agricultural processing residue);
    b. Wood (forest products, logging residue, primary mill residuals, secondary mill residuals, urban wood wastes and wastes from pulp and paper manufacturing0; and
    c. Urban residual (railroad ties, mixed paper, construction and demolition debris, refuse derived fuel, residential municipal solid waste, scrap tires, and yard wastes)
    d. Units firing multiple classifications of biomass to be subject to the more stringent classification.
3) Performance from "operating" units should only be used
4) Pollutant co-dependence must be carefully considered

<u>Inability of Single Boiler to Meet the Proposed Limits [page 3]:</u>
Further, the source data shows that no existing facility simultaneously meets all the proposed limits, even the few plants with environmental controls. Pollutant co-dependence is critical in understanding the environmental emissions from the combustion process as several pollutants are related to each other – some inversely to others, such as NO_X and CO. The relevancy of utilizing the results from multiple boilers as the "best performer" for individual pollutants (one for CO and another for PM) is therefore not justified when setting limits for new units. The use of this method does not account for the co-dependence of these pollutants as they relate to boiler operating parameters and the variability in biomass type and composition.

<u>Variability of Emissions Due to SSM Events [pages 4-5]:</u>
Startup periods are not predictable and should not be included in the emissions averaging period. We recommend that startup periods be treated outside the averaging period similar to "periods of malfunction" (CAA section 112(d)).

The combustion of biomass has its challenges. Biomass has a low calorific value and high moisture content when compared to fossil fuels. Biomass characteristics can vary significantly based on a number of factors, including species, geographic origin, and time of year. Thus, there is variability in biomass that is not inherent to the combustion of fossil fuels. This variability along with the extreme dynamics associated with startups of a biomass fired boiler make it unreasonable to include them in the emissions compliance averaging period. The proposed ruling states that “Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source’s operation.” We have not found this to be the case in practice when it comes to biomass combustion. The variability in biomass makes it difficult to standardize an optimized mode of operation on a consistent basis, particularly during startup conditions.

Thus, emission control during startup is anything but predictable and consistent. The source data supports this. The data presented for CO emissions fluctuates significantly during the performance testing period. Metso believes that no technology is commercially available, including oxidation catalysts, to control emissions of CO during startup or shutdown to the degree that would be required to satisfy the proposed rulings. These variations are further complicated by the fact that many units are not based-loaded and must deal with fluctuations in load that will create transient conditions, even during normal operation. This can result in frequent operating instabilities lasting several hours, compounding the unpredictable nature of biomass combustion and resulting emissions.

American Forest & Paper Association, EPA-HQ-OAR-2002-0058-2313.1[1].pdf, letter from Paul Noe, Vice-President of Public Policy, August 23, 2010:

Limits do not Properly Account for Variability [pages 16-17]:
EPA has improperly developed a CO standard that boilers must meet at all times based on 3-run stack tests that fail to properly characterize the highly variable nature of CO emissions in solid fueled boilers. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 90 percent of full load during normal operating conditions. Therefore, a CO stack test is going to represent the best operation of any boiler. EPA has used only 3-run stack test data, which represents only a small and unrepresentative snapshot in time captured during the best operating conditions, to set emission limits for a pollutant that is highly variable.

In fact, as demonstrated in the comments below, further analysis of CO CEMS data included in EPA's database for top performing units in each of the solid fuel subcategories reveals that even the top performing sources would not be able to meet the proposed CO standards that are based on the performance of those very units. Further analysis of record data also clearly shows that EPA is mistaken in its suggestion that CO emissions do not vary with load. In fact, to adequately accommodate expected CO emissions variability with load, the 2004 Industrial Boiler MACT rule did not require CO CEMS data obtained at less than 50 percent of maximum load to be included in the 30-day CO average. EPA's proposal not to accommodate load variability is not supported by the record and inexplicable as a technical matter.

EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages … [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards." On the other hand, EPA uses short term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

More generally, EPA proposes to use the 99 percent upper predictive limit ("UPL") to accommodate and reflect variability in the operation of the best performers in calculating the MACT floor. The use of the 99 percent UPL calculated on only a small number of sources in a subcategory does not adequately capture variability or serve to predict the MACT floor level achievable by the top performers. In essence, the Agency is using this statistical method in an attempt to overcome the limited amount of emissions data available for top performers. However, this statistical approach cannot overcome the fact that the data are not representative of the entire population of boilers in each subcategory and that the available data do not reflect the true variability of the top performing sources.

In the final rule, EPA must use data to set the standard that are consistent with the form of the standard. A s compliance with the CO standard is to be measured at all times using CO CEMS for units of 100 MMBtu/hr and greater and the averaging time is 30 days, EPA should use 30-day CEMS data from affected boilers to establish the appropriate MACT floors and not 3-run stack test data. To assure that startup, shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction.

<u>Industrial Boilers are Different than Utility Boilers [pages 26, 28]:</u>
The air emissions profile of the many multi-fuel-fired boilers in the pulp and paper industry varies with fuel mix, making it difficult to establish a “typical” emissions profile. Many times boiler operators have emission limits that change based on the fuel fired. The fact that these boilers must often adapt quickly to varying process steam demand and experience frequent load swings also makes characterizing “typical” emissions difficult. Permitting changes to a multi-fuel fired boiler is challenging because predicting projected actual emissions following the change is difficult, as fuel mix can vary based on season, fuel cost, and operation of other equipment at the facility.

Industrial boilers should not be regulated in the same manner as electric utility boilers because of the differences in boiler size, fuel mix, application, design, operation, and the higher relative cost of emissions control. Although industrial boilers far outnumber electric utility boilers, industrial boilers produce a fraction of the steam that utility boilers produce and consume a fraction of the amount of fossil fuels that utility boilers consume. Industrial boilers also use their fuel more efficiently than utility boilers when the boilers produce both heat and power to support mill operations and do not experience the line losses that happen when electricity is transferred to utility customers. As previously highlighted, industrial boilers in our industry also experience frequent load swings over the course of an operating day that utility boilers do not typically experience, and they typically burn more variable fuel types than utility boilers. [A specific example of the swings was provided by Packaging Corporation of America in their comment letter.[1]]

[1] Packaging Corporation of America (PCA), EPA-HQ-OAR-2002-0058-2913.1[1].pdf: “As alluded to earlier, boiler performance can be dramatically affected by variations in fuel quality. Each of our facilities consumes over 1,000 tons per day of solid fuels. Fuel combustibility is affected by heavy precipitation (rain or snow) as well as the amount of “fines” in the fuel (e.g., sawdust versus bark, stoker coal versus coal dust). Slugs of wet fuel to an individual boiler cause abrupt swings in steam load, drum level, opacity, and carbon monoxide levels. Our mills are configured with multiple boilers each feeding steam to a common steam header. Fuel quality changes at one boiler results in indirect impacts on other boilers due to the common steam system. For example, if a slug of wet fuel in Boiler A causes an abrupt drop of 15,000 pounds of steam generation, other boilers in the common steam system must rapidly increase steaming rates to compensate for the loss of steam at Boiler A.

Pulp and papermaking operations, by their very nature, induce power boiler load swings. For example, a single paper machine may have a steam demand of 180,000 pounds of steam during normal operation. However, steam demand will drop by 70 percent during a “sheet break” on the paper machine. The duration of a sheet break is unpredictable – it could be as little as 10 minutes or as much as an hour or more. The point is this – what happens at a paper machine (or, for that matter, a pulp digester, a spent liquor evaporator or any other steam-demanding unit of operation) has a dynamic effect on the power boilers supply process steam.

To illustrate the seriousness of the boiler load variability issue, we evaluated the amount of steam load variations occurring at four affected boilers at our Tomahawk, WI [mill]. In a single month, the lowest average variation in steam load (min/max variation in hour average on a daily basis) at any one of the four units is 22 percent while the highest average variation in steam load is 46 percent. Overall, the average min/max variation for the four units is 33 percent. As compliance stack tests typically occur (actually are required) at sustained loads of 80 percent or more for the duration of the test, real world data shows that on an average day, even our most stable boiler exhibits load variation exceeding that which is required for a standard stack test.

CO Limits Must Consider Long-Term Variability [pages 103-104]:

EPA has improperly developed a CO standard that boilers must meet at all times based on 3 run stack tests with no acknowledgment of the highly variable nature of CO emissions in solid fueled boilers. EPA has collected a limited amount of 30-day CO CEMS data, but has collected much more CO stack test data. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 90 percent of full load during normal operating conditions. Therefore, a CO stack test is going to represent the best operation of any boiler. EPA has used only 3-run stack test data, which represents only a small snapshot in time captured during the best operating conditions, to set emission limits for a pollutant that is highly variable. Even EPA acknowledges this fact in the preamble at 75 FR 32021: “We believe that single short term stack test data (typically a few hours) are probably not indicative of long term emissions performance, and so are not the best indicators of performance over time.”

We are concerned that EPA is developing a standard for CO based on stack test data while requiring compliance based on a CO CEMS. It appears that EPA is using one method to set the standard and a totally different method to show compliance. The U.S. Court of Appeals for the D.C. Circuit has ruled that "a significant difference between techniques used by the Agency in arriving at standards, and requirements presently prescribed for determining compliance with standards, raises serious questions about the validity of the standard." Portland Cement Ass'n v. Ruckelshaus, supra, at 396. We believe that using stack test data to set the standards and then CEMS to show compliance qualifies as “a significant difference between techniques.” The primary difference between these two methods will be that the variability experienced during normal operations will not be captured during the stack test but will become apparent as the facility operates a CEMS over time. We believe that if EPA wishes to use CEMS to show compliance with the standard, then the standard must be developed using CEMS data. Using short-term test data to identify ‘best performers’ and then setting a 30-day average emission limit based on the short-term data suffers from three significant shortcomings:

1. The majority of the best performers have a single Method 10 test which provides almost no information on CO temporal variability.
2. Short-term tests do not reflect startup, shutdown, or malfunction conditions, nor do they capture fluctuations in emissions due to load swings, fuel quality changes, or changes in fuel mix (in multi-fuel boilers).
3. Best performers should be those units having the lowest long-term average CO emission rates, not those with the lowest 3-hour test averages.

We believe that this fundamental flaw (assuming single or even multiple compliance stack tests capture CO emission variability) can be corrected. Additionally, correcting this flaw will provide the basis of an improved standard. Certainly, if EPA wishes to use CEMS to show compliance with the standard, then the standard must be developed using CEMS data.

…

Additionally, a closer examination of the data in the emissions database shows that not only does CO vary with load, but it can vary quite a bit over a 30-day period. The following graph represents the CO data from biomass boiler PB-44 at Facility TXDibollTemple-Inland plotted against the steam data. [graph not included here] The second graph presented below shows the CO versus load data in the MACT database for VA Phillip Morris. [graph not included here]

These graphs show that EPA's statement in the preamble that CO does not vary with load and no adjustment is needed for CO emissions variability for load is not accurate. In fact, the MACT floor memo states that the 2 biomass boilers for which EPA gathered 30-day CO CEMS data show higher CO emissions at lower loads. It is improper to exclude the data for the Domtar Arkansas boiler from the discussion just because it was burning a material that may be defined as solid waste; the unit is still operating as a biomass boiler and the data can be used with the Diboll data to show a trend: CO emissions are higher at low loads. Data obtained during periods of SSM also should not be excluded from any analysis of 30-day CO data because EPA has stated that the CO limit must be met at all times, even during periods of SSM. Therefore, it is appropriate to include emissions data from these periods, especially from a top performing boiler like the Diboll boiler, in floor setting.

The original Boiler MACT rule recognized that CO emissions could be higher at low loads by not requiring CO CEMS data obtained at less than 50 percent of maximum load to be included in the 30-day CO average. We believe that is an appropriate exclusion for the revised rule. EPA has recognized boiler, or burner, turndown ratio as a factor affecting performance in several contexts. See, EPA, Final Technical Support Document for HWC MACT Standards, Vol. IV, p. 3.6 (July 1999); EPA Region 6 Center for Combustion Science and Engineering, Hazardous Waste Combustion Unit Permitting Manual, Component 1 How to Review a Test Burn Plan, p. D-5.5 (Tetra Tech Jan. 1998).

…

Whether or not the boiler can meet the proposed MACT limit for its category based on one 30-day average does not serve to indicate whether variability of CO emissions was properly accounted for when setting the MACT floor. In fact, upon further analysis of the data, development of daily averages and rolling averages that include the data available for the previous number of days in the dataset indicates that there are several days where this boiler, which is among the top performers, would NOT meet the proposed CO limit on a 30-day rolling average basis, as indicated in the table below. [Table Not Included]

99 UPL of the 30-day data, and the proposed CO limit for biomass suspension boilers differ quite greatly and that use of 30-day operational data would likely result in a much different MACT floor than use of 3-run stack tests because the 30-day averages and the UPLs of the 30-day averages are much higher than the average of a 3-run stack test performed at full load, steady state conditions. The first chart contains data from PB-44 at Facility TXDibollTemple-Inland, which is a top performer in the biomass suspension burner category. The second chart shows data from boiler P05 at facility WVDuPontWashingtonWorks, which is a top performer in the stoker coal boiler category. The third chart shows data from boiler B3 at facility VAPhilipMorrisPark500, which is virtually identical (same size, same fuel, same type of control device) to boiler B2 at this facility, which is a top performer in the PC coal boiler subcategory. [charts not included – refer to summary table as follows]

Summary of Data presented in Graphs Above:

Facility	Proposed Limit	99 UPL of Hourly Data	CO 30-day Avg	CO Stack Test Avg	
TX Diboll	1010	2195	747	69	ppm @ 3% O2
VA Phillip Morris	90	83	54	13	ppm @ 3% O2
WV DuPont	50	39	26	16	ppm @ 3% O2

Variability of Biomass Fuels [page 180, 210]:
The majority of biomass fuels burned by the pulp and paper industry are wet fuels, and the moisture content varies depending on the source of the fuel, the weather conditions (e.g., rainfall on outdoor storage piles), and the type of fuel (bark, sawdust, wood chips, etc.). Higher moisture fuels, as well as variations in moisture content, cause less even combustion and therefore, higher CO emissions.

- Many pulp and paper industry combination boilers burn wood residues from their wood yard operations, which do not run continuously. As such, the amount of wood residue burned varies throughout each day, as does the type of wood residue (bark, sawdust, undersized chips). Such variations in the fuel quality, size, and type cause less consistent combustion and therefore, higher CO emissions.
- EPA recognizes that wet fuels or varying moisture content of the fuel can result in incomplete combustion, and that the design of the unit influences organic HAP emissions. Specifically, the preamble to the proposed rule states:

> "The design of the boiler or process heater, which is dependent in part on the type of fuel being burned, impacts the degree of combustion. Boilers and process heaters emit a number of different types of HAP emissions. Organic HAP are formed from incomplete combustion and are influenced by the design and operation of the unit." [35 FR 32017].

There are factors beyond the boiler operator's control that can cause emissions to vary over a period of days and not hours. For example, the weather will impact moisture content of solid fuels, which will affect how the fuels combust over a period of days, not hours. For a biomass boiler, the fuel supply and fuel characteristics could also vary over a period of days because mills have multiple biomass fuel suppliers providing both green and dry wood. For all types of boilers, the pollutant content of the fuel will vary over a period of days, as evidenced by the range of results obtained during the 30-day fuel sampling required by EPA for many ICR Phase 2 participants.

CO Limits are not Achievable [pages 203-204]:
Carbon monoxide is the most common product of incomplete combustion (PIC), and because of its associated chemical kinetics, is one of the most difficult PICs to oxidize completely. As such, CO emissions have historically been used as an indicator of the quality of the combustion process. The concept is that low CO emissions would equate to negligible emissions of other

organic compounds. While this is true in general, the mechanisms by which CO is formed and destroyed in the combustion process are different than for other organics. As such, in cases where other organic compounds have been completely oxidized, CO concentrations may still be elevated. While the tendency is to think that further reductions in CO emissions will improve the quality of the combustion, and in turn minimize emissions of other organic compounds, this is not necessarily true. Instead, forcing CO emissions lower and lower ends up overconstraining the combustion process, producing negative impacts on other air quality concerns, without documented improvements in emissions of organics.

Most boilers are designed to mix fuel and air at an appropriate ratio, and to provide sufficient residence time for the fuel to combust completely. Obviously, these factors are fuel-dependent, as a gaseous fuel will require less time for complete combustion than a liquid fuel, which in turn requires less time to burn than a solid fuel. The need for longer residence time is why the radiant sections in solid-fuel fired boilers are larger than for gas-fired units. The size of the boiler is typically optimized to allow for complete combustion, while minimizing the cost of construction materials. If the construction cost were not a concern, a new boiler could be designed with additional residence time to complete the combustion process and minimize CO emissions.

…

However, there are also a number of negative impacts associated with operating a boiler at higher levels of excess oxygen. The residence time of combustion gases in the furnace decreases, resulting in less time for complete burnout of intermediates such as CO. Many boilers do not have sufficient fan capacity to run with elevated excess oxygen at the high end of the load range. Therefore, these units would effectively be derated by such a strategy. A site might have to add another boiler to offset the reduction in steam generating capacity. If the excess oxygen is increased to very high levels, CO and hydrocarbon emissions will increase and flame stability is impaired, mainly because this leads to a cooler flame.

The minimization of excess oxygen in boiler applications is a key feature for maximizing boiler efficiency. For a given fuel, the boiler efficiency is defined by the amount of combustion air that is used, and the difference between the ambient temperature and the stack exhaust temperature. The more air that is heated up through the combustion process, the more heat is lost to the atmosphere, causing the boiler to be less efficient. A less efficient boiler will require more fuel to be fired to produce a given amount of steam. The additional fuel firing results in higher operating costs, and higher greenhouse gas emissions.

Minimizing the level of excess oxygen is also a primary strategy for reducing NO_X emissions from a boiler. The NO_X formation mechanisms are dependent upon the temperatures in the flame zone, and the stoichiometry of the fuel and oxygen introduced into the furnace. Reducing the level of excess oxygen reduces the peak flame temperature, which reduces the rate at which the nitrogen in the air dissociates. As such, there is less monatomic nitrogen available to be oxidized to form 'thermal NO_X'. Similarly, if there is less oxygen present, the monatomic nitrogen is less likely to be oxidized (and more likely to react with a second monatomic nitrogen to form diatomic nitrogen). This reduces both the amount of thermal NO_X, and the 'fuel NO_X' (NO_X that is formed by the release of fuel-bound nitrogen). Therefore, increasing the level of excess oxygen will result in higher NO_X emissions.

<u>The Proposed Limits Do Not Properly Account for SSM [pages 245-246]:</u>

EPA's MACT floor-setting approach … mischaracterizes the role startup and shutdown data plays (or rather, does not play, as the case is here) in EPA's floor-setting process. As noted above, EPA claims that the agency considered startup and shutdown periods when setting the floors because CEMS data, relied on by EPA in "establishing the standards," included data from those periods. See Proposed Boiler MACT Rule at 75 FR 32012.

Despite this claim, however, EPA does not rely on the CEMS data when setting the floors for boilers and process heaters. To the contrary, as indicated by the ERG MACT floor memorandum in the docket (EPA-HQ-OAR-2002-0058-0815), EPA uses test run data collected through the ICR phase II testing process, which reflect normal (often steady state) operating conditions, to set the proposed floors. Thus, according to EPA's own docket materials, the data used to set the proposed floors fail to account for the dynamic conditions and variable emissions occurring during startup and shutdown episodes. Furthermore, as the ERG memorandum makes abundantly clear, EPA's approach does not make use of the CEMS data (with the startup and shutdown information) in its variability analysis where it would be the most helpful in reflecting real world fluctuations in emissions. Id.

The following data is a subset of the data available to EPA within the docket. These excerpts reflect start-up and shutdown CO data from two facilities. One is a coal fired unit and one is a wood fired unit. Both data sets provide EPA data during periods of start-up and shutdown. While the absolute values are different in both cases the data indicates that carbon monoxide levels are up to twenty times greater during such periods. This is due to the influence of oxygen levels. When fuel values are low, as during periods of start-up and shutdown, oxygen levels are higher, making the corrected pollutant concentrations much higher. Further, as noted in the data set, the raw pollutant levels are elevated due to unstable combustion. [charts not included here]

If EPA had examined these data in some detail, it would have recognized two important aspects of the startup and shutdown periods. First, during startup periods, the oxygen content of the flue gas is generally very high, resulting in high calculated concentrations of pollutants, when they are corrected to 3 or 7 percent oxygen. Second, during shutdown periods many types of boilers continue to emit pollutants for some time while the fuel feed rate has gone to zero. Thus, during those periods the pollutant emission rates when measured in terms of the heat input rate would contain a zero in the denominator and would equal infinity. Combining emissions during shutdown periods with all operating periods would mean an emission limit of infinity. Based on this ridiculous outcome, we recommend that EPA exclude periods of startup and shutdown from its numerical standards and replace them with work practice standards aimed at minimizing pollutant emissions.

It is apparent that EPA did not consider this data when it established the proposed standards. In each of the cases present above, the proposed standards would have been exceeded during a 30 day period simply due to a start-up and shutdown condition. We believe that EPA should strongly reconsider this information before finalizing a standard.

GPI, EPA-HQ-OAR-2002-0058-2723.1[1].pdf, letter from Steven G. Hanson, Resident Manager, August 23, 2010:

Biomass CO Variability was not Considered [pages 8-9]:
GPI - Macon Mill believes the establishments of emission limits for the broad "biomass" subcategory does not accurately reflect the wide variation of emissions anticipated for various types of biomass fuel combusted throughout the nation. The establishment of appropriate subcategories and emission limitations is also further complicated by the multi-fuel nature of many biomass boilers. In this section, GPI - Macon Mill highlights concerns over the use of particular testing data for specific units and pollutants and their appropriateness for establishing generic "biomass" limitations.

In reviewing the data utilized to establish the MACT floor for biomass boilers for CO, GPI - Macon Mill has concerns regarding the significant variability in emissions due to fuel combustion characteristics within the broad biomass subcategory. The testing data itself documents the significant differences in CO (and other pollutant emissions) in boilers combusting bagasse, bark, industrial sludge, hog fuel and other biomass-derived fuels. This is of particular note when reviewing emission limitations established for new sources, as those rely solely on the "best performing source" within that subcategory, without further consideration of the uniqueness of the actual biomass fuel beins combusted.

The CO MACT floor for new, biomass-fired, fluidized bed boilers was based on a boiler combusting the following fuel mixture:

- 64% hog fuel (dry biomass)
- 19% industrial sludge
- 17% natural gas

Of particular note for this unit is the fact it was combusting 17% natural gas. It is reasonable to expect that the emissions of CO from this unit would have likely been significantly higher during the stack testing had it been combusting a higher percentage of hogged fuel. Additionally, hogged fuel is generally characterized as “dry biomass” whereas many other biomass fuels are “wet”. The difference in combustion performance when combusting a wet or dry fuel is substantial, particularly with respect to CO emissions.[2] By relying on this unit to establish the new source MACT floor for all new fluidized bed biomass units, EPA has inherently presumed that all new units will include 1) natural gas combustion capabilities and 2) are combusting a dry biomass. This presumption inherently results in a new source MACT floor for CO emissions that is too low to appropriately represent the broad category of “biomass”.

New biomass units being considered that would combust in excess of the 64% hogged fuel and that would combust wet biomass fuel are subsequently penalized for reliance on a higher percentage of wet biomass fuel. This unit is truly not representative of the biomass subcategory, particularly for establishing a new biomass source CO MACT floor. Figure 1 compares the CO testing data for the unit presently relied upon to establish the CO floor for new biomass fluidized bed boilers and the top performing fluidized bed unit firing wood bark based biomass without any natural gas.

[2] Fuel moisture content impacts the temperature characteristics within the combustion chamber. Fuels with a higher moisture content require heat to drive off water vapor before char combustion of the biomass fuel actually commences. This impact on temperature in the combustion chamber impacts CO formation in the combustor.

Figure 1. CO test data comparison

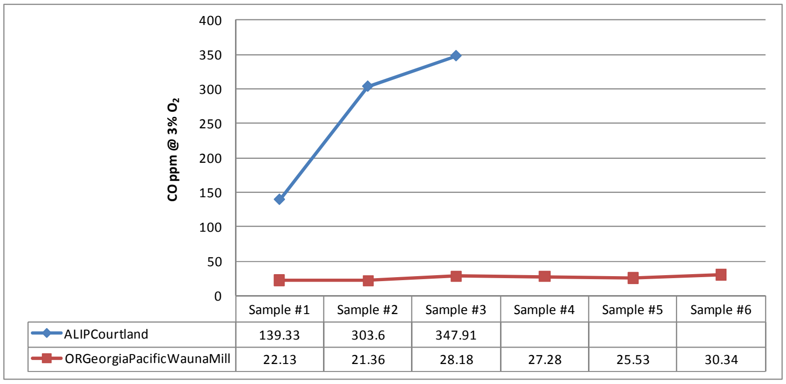

Figure 1 illustrates that the top performing unit firing wood bark (ALIPCourtland) had tested CO emissions in the range of 139 ppm to 348 ppm (average of 264 ppm) as opposed to 21 ppm to 30 ppm (average of 26 ppm) for the boiler combusting the mixture of hog fuel, industrial sludge, and natural gas. There is an order of magnitude difference between the average test values of these two units. This demonstrates the need for further classification within the biomass subcategory. [Further, International Paper submitted comments describing how this particular boiler at would have been out of compliance for a number of periods if U.S. EPA had considered the CEMS data associated with this boiler, not just the test data.[3]]

GPI - Macon Mill encourages EPA to complete a more comprehensive review of the present biomass subcategory and related testing data to develop more refined subcategories, such as woody biomass, dry or wet biomass, bagasse, etc.

<u>Startup and Shutdown Emissions are not Properly Considered [pages 11-12]:</u>
EPA has not appropriately accounted for startup and shutdown emissions. While EPA makes the simplistic statement that boilers do not normally startup and shutdown more than once per day, they have not accounted for the fact that the startup and shutdown process is not like turning a light switch on and off – such processes on boilers can take several hours, with safety being a predominant concern in the practices employed. Additionally, operation of emission control devices is not always feasible during these modes. GPI has the following concerns regarding startup and shutdown related emissions and compliance with proposed emission limitations:

- A typical startup or shutdown for GPI's existing biomass boiler is a period of approximately 8 hours. For parametric monitoring establishing 12-hour block averages, this comprises 67% of the averaging time, during which there is a strong probability lb/MMBtu emission limitations would be exceeded.

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[3] International Paper, EPA-HQ-OAR-2002-0058-2777.1[1].pdf: International Paper's Courtland Mill (CT) #3 Combination Boiler was selected by EPA as the number 2 floor unit for establishing the CO limit for existing biomass fluidized bed boilers. CT#3's short term CO emissions test data contributed to the proposed CO limit for such units of 250 ppm corrected to 3% O2 (30-day rolling average). The CT #3 unit had a continuous CO monitor for a two year period (2002 and 2003). The historical continuous CO data for this unit shows it would not comply with the proposed limit for 35 of the 30-day rolling average periods during 2003 even though in 2002, it would have complied throughout the year. In 2002, CO emissions on a 30-day rolling average basis varied from 9 ppm to 136 ppm. While this is within range of the proposed limit, subsequent data for 2003 showed otherwise. CO on a 30-day rolling average in 2003 ranged from 54 ppm to 636 ppm which is well above the proposed limit. The reason(s) for this change in CO levels is not known with certainty. This demonstrates the fact that even a floor unit cannot achieve its proposed CO limit at all times under normal operations.

- Control devices may not be capable of normal operation during periods of startup and shutdown, meaning monitored parameters would not be within ranges established during performance testing.
- Ranges established during performance testing for parametric monitors are based on maximum normal operations, which differ substantially from startup and shutdown processes. …

EPA makes the following statement regarding their assessment of startup and shutdown emissions from a CO CEM on page 32013 of the Federal Register: *Continuous emission monitoring data obtained from best performing units, and used in establishing the standards, include periods of startup and shutdown.* Upon review of the data used to set the CO limits, which apply at startup and shutdown, GPI disagrees with EPA's above statement. In establishing the CO limit for Suspension Burners/Dutch ovens designed to burn biomass, EPA relied on the following data:

- Stack test data for suspension burners/dutch ovens firing biomass
- CEMS data for a single biomass suspension burner during a period of fluctuations in load (i.e., 17% - 77% capacity)

Upon review of this data, it is clear that EPA made a key assumption: startup and shutdown periods are assumed to be part of the CEMS data set, even though the operating capacity never reached "zero" during this time period. In comparing the stack tests to a single set of 30-day CEMS data, EPA concluded that the variability in setting the MACT floor accounts for any and all fluctuations <u>in any type of biomass boiler</u>.

EPA has made several large and possibly inaccurate assumptions in their evaluation. First, they have presumed that only one set of 30-day data from a CEM is sufficient for concluding that all startup and shutdown variability has been addressed, despite the fact that it is not clear that a true startup or shutdown event actually occurred during the 30-day period.[4] Second, EPA has presumed that the performance characteristics of a suspension burner/dutch oven are representative of all combustor types, despite having clearly recognized the importance of combustor type on resulting CO emissions.

EPA has a responsibility to set and enforce limits that a source can meet (i.e., achievable), not create a limit that is unattainable by any source in the US, new or existing. The proposed approach is the equivalent to setting the speed limit at an oncoming ramp to an interstate at 5 mph, and then expecting the car to immediately reach the speed of interstate traffic (55 mph or more) with no adverse events. The expectation of a source to comply immediately upon startup, which is known to have higher CO emissions,[5] <u>without</u> taking into account these emissions when setting the MACT floor, is no different. While EPA states that startup and shutdown data have been used to establish the standards, this statement is false for biomass stokers and biomass fluidized bed boilers. GPI urges EPA to appropriately consider emissions during startup and shutdown.

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[4] For many pulp and paper facilities, large boilers such as the existing biomass boiler typically shutdown only one or two times per year for emergency or maintenance purposes.

[5] While GPI does not have a CO CEM on the existing biomass boiler to support this statement, the Recovery Furnace CO CEM does show a pattern of higher CO emissions during startup procedures. This stems in part from the use of fossil fuel in the boiler during startup and the need to bring the furnace up to the typical combustion temperature. A similar trend would be expected in a woody biomass boiler.

Load Variability Must Be Accounted for in Limits [pages 13-14]:
Although EPA recognizes that lower load on boilers renders higher CO emissions, this variability does not appear to be fully taken into account. Since EPA also recognizes that organic HAP and CO emissions are a function of the combustion process, the load variability reasoning is inherently flawed. As discussed in the startup and shutdown emissions section, EPA reviewed a very limited data set of CEM data to “confirm” their conclusion that the statistical analysis on short-term stack testing data (and hence the resulting emission limitation) appropriately accounts for load variability for all biomass combustion units. GPI urges EPA to complete a more thorough review of the variability issue prior to finalizing the standards, including a review of load variability data for boilers from each combustor category to ensure load variability and combustor variability is appropriately assessed.[6]

[6] GPI does not operate any CO CEMS and therefore cannot provide any data to assist with the variability analysis.

Proposed Boiler MACT – Extracted Sections from Public Comments Submitted Related to Establishment of CO Limits for Biomass Boilers - Continued

Comments similar to those submitted by Babcock & Wilcox, Metso, AF&PA and GPI were also submitted by a number of other industry groups and pulp and paper mills throughout the Southeast. Such comments are not reiterated here.

- National Alliance of Forest Owners (NAFO), EPA-HQ-OAR-2002-0058-2750.1[1].pdf
- National Council for Air and Stream Improvements (NCASI), EPA-HQ-OAR-2002-0058-2804.1[1].pdf
- Georgia Paper & Forest Products Association, Inc. (GPFPA), EPA-HQ-OAR-2002-0058-2905.1[1].pdf
- South Carolina Pulp & Paper Association (SCPPA), EPA-HQ-OAR-2002-0058-2691.1[1].pdf
- Tennessee Paper Council, EPA-HQ-OAR-2002-0058-2691.1[1].pdf

- Augusta Newsprint, EPA-HQ-OAR-2002-0058-3153.1[1].pdf
- Domtar, EPA-HQ-OAR-2002-0058-2823.1[1].pdf
- Georgia-Pacific, EPA-HQ-OAR-2002-0058-2745.1[1].pdf
- International Paper, EPA-HQ-OAR-2002-0058-2777.1[1].pdf
- KapStone Kraft, EPA-HQ-OAR-2002-0058-2673.1[1].pdf
- Packaging Corporation of America (PCA), EPA-HQ-OAR-2002-0058-2913.1[1].pdf
- SP Newsprint, EPA-HQ-OAR-2002-0058-3128.1[1].pdf
- Temple-Inland, EPA-HQ-OAR-2002-0058-2691.1[1].pdf
- Weyerhaeuser, EPA-HQ-OAR-2002-0058-2797.1[1].pdf

APPENDIX D

SIP CONSTRUCTION PERMIT APPLICATION FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: ____________ Application No. ____________

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Graphic Packaging International, Inc.
AIRS No. (if known): 04-13- 021 - 00001
Facility Location: Street: 100 Graphic Packaging International Way
City: Macon Georgia Zip: 31206 County: Bibb

2. Facility Coordinates

Latitude: ° ' " **NORTH** Longitude: ° ' " **WEST**
UTM Coordinates: 253,800 m **EAST** 3,628,900 m **NORTH** **ZONE** 17

3. Facility Owner

Name of Owner: Graphic Packaging International, Inc.
Owner Address Street: 100 Graphic Packaging International Way
City: Macon State: GA Zip: 31206

4. Permitting Contact and Mailing Address

Contact Person: Kathleen Wheeler Title: Environmental Manager
Telephone No.: (478) 784-4425 Ext. ____ Fax No.: (478) 784-4444
Email Address: kathleen.wheeler@graphicpkg.com
Mailing Address: Same as: Facility Location: ☒ Owner Address: ☐ Other: ☐
If Other: Street Address: ____________
City: ____________ State: ____________ Zip: ____________

5. Authorized Official

Name: Steven G. Hanson Title: Resident Manager
Address of Official Street: 100 Graphic Packaging International Way
City: Macon State: GA Zip: 31206

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: Steven Hanson Date: 8/9/11

6. Reason for Application: (Check all that apply)

- ☐ New Facility (to be constructed)
- ☒ Existing Facility (initial or modification application)
- ☒ Permit to Construct
- ☒ Permit to Operate
- ☐ Change of Location
- ☒ Permit to Modify Existing Equipment: Affected Permit No.: 2631-021-0001-V-03-0

☐ Revision of Data Submitted in an Earlier Application

Application No.: ______

Date of Original Submittal: ______

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☐ **No** ☒ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: Trinity Consultants

Name of Contact: Deanna Duram, P.E., C.M.

Telephone No.: (678) 441-9977 Fax No.: (678) 441-9978

Email Address: dduram@trinityconsultants.com

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

City: Atlanta State: GA Zip: 30346

Describe the Consultant's Involvement:

Permit application assistance.

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

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	2.02 Storage Tank Physical Data
0	2.03 Printing Operations
0	2.04 Surface Coating Operations
0	2.05 Waste Incinerators (solid/liquid waste destruction)
0	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
0	3.01 Scrubbers
1	3.02 Baghouses & Other Filter Collectors
0	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
1	6.00 Fugitive Emission Sources
1	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: By end of third quarter 2011

11. **If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?**

☐ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)		
Nitrogen oxides (NOx)		
Particulate Matter (PM)		
PM <10 microns (PM10)		
PM <2.5 microns (PM2.5)		
Sulfur dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Total Hazardous Air Pollutants (HAPs)		
Individual HAPs Listed Below:		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	2300	2300	2666	2666
Nitrogen oxides (NOx)	2760	2760	2284	2284
Particulate Matter (PM)	1600	1600	1081	1081
PM <10 microns (PM10)	1080	1080	761	761
PM <2.5 microns (PM2.5)	918	918	706	706
Sulfur dioxide (SO_2)	5290	5290	2267	2267
Volatile Organic Compounds (VOC)	877	877	900	900
Total Hazardous Air Pollutants (HAPs)	935	935	792	792
Individual HAPs Listed Below:				
Listed in Previous Title V Application				

14. 4-Digit Facility Identification Code:

SIC Code: 2631 SIC Description: Paperboard Mills

NAICS Code: 322130 NAICS Description: Pulp Mills

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

See Section 2.2 of narrative report.

16. Additional information provided in attachments as listed below:

Attachment A - Macon Mill Facility Diagrams

Attachment B - Emission Calculations

Attachment C - BACT Supporting Information

Attachment D - Permit Application Forms

Attachment E - Title V Database and Proposed Permit Conditions

Attachment F -

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal:

☐ Flow Diagram or date of previous submittal: September 2009

Facility Name: Graphics Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
B002	No. 2 Power Boiler	Combustion Engineering VU-X	After the project, the No. 2 Power Boiler will only combust natural gas and the scrubber will no longer be utilized.
B005	No. 3 Biomass Boiler	Andritz Inc. custom design PB 350	The No. 3 Biomass Boiler generates steam for paper making, pulping, thermal processing and facility heating.
CT01	Cooling Tower	TBD	Supports the new steam turbine generator.
TK01	Lube Oil Tank	TBD	Supports the new steam turbine generator
TK02	Hydraulic Oil Tank	TBD	Supports the new steam turbine generator
B903	Ash Storage Silo	TBD	Supports the No. 3 Biomass Boiler by storing fly ash from the baghouse for offsite transfer.
B904	Sand Storage Silo	Andritz	70 ton silo supports the No. 3 Biomass Boiler fluidized bed.
B905	Sorbent Storage Silo	TBD	Supports the No. 3 Biomass Boiler dry sorbent injection control system.
TK03	Aqueous Ammonia Day Tank	TBD	250 gallon day tank to support SNCR.

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
B005	3 Natural Gas startup burners	Balanced	45 MMBtu/hr (each burner)	25	Initiate end of 3rd quarter 2011	Initiate end of 3rd quarter 2011	N/A
B005	2 Natural Gas load burners	Balanced	122 MMBtu/hr (each burner)	25	Initiate end of 3rd quarter 2011	Initiate end of 3rd quarter 2011	N/A
B002	Removing coal and fuel oil capability		198		1947-1948	1947-1948	N/A

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

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
B005	**Natural Gas**	**530.4**	**MMcf**	**UNK**	**UNK**	**0.24 MMscf/hr**	**0.06 MMscf/hr**	**1,024 Btu/cf**	**1,024 Btu/cf**				
B005	**Wood**	**729,216**	**tons**	**42**	**58**	**83.24 ton/hr**	**83.24 ton/hr**	**7.45 MMBtu/ton**	**7.45 MMBtu/ton**	**<1**	**<1**	**6% fm biomass**	**6% fm biomass**
B005	**Sludge**	**65,700**	**tons**	**42**	**58**	**7.5 ton/hr**	**7.5 ton/hr**	**3.83 MMBtu/ton**	**3.83 MMBtu/ton**	**varies**	**varies**	**6% fm biomass**	**6% fm biomass**
B002	**Natural Gas**	**1,694**	**MMcf**	**42**	**58**	**0.193 MMscf/hr**	**0.193 MMscf/hr**	**1,024 Btu/cf**	**1,024 Btu/cf**				

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Wood	**TBD**					
Sludge	**GPI Mill Residuals**					
Natural Gas	**TBD**					

Facility Name: Graphic Packaging International, Inc **Date of Application:** January 2011, revised August 2011

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ ºF)	Storage Temp. (ºF)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
TK01	Lube Oil Process Tank	4,000	Turbine Lube Oil	<0.01 psi @ ambient	Ambient	Submerged	**C: 2011-2012**	Horizontal Tank	Atmospheric Vent
TK02	Hydraulic Oil Process Tank	4,000	Turbine Hydraulic Oil	<0.01 psi @ ambient	Ambient	Submerged	C: 2011-2012	Horizontal Tank	Atmospheric Vent
TK03	Aqueous Ammonia Day Tank	250	< 20% ammonia	9.1 psi @ 60 deg F	Ambient	Submerged	C: 2011-2010	Fixed Roof	Atmospheric Vent

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
B05N	B005	SNCR	2011-2012	TBD	N/A	TBD	320	320,000
B05D	B005	Dry Sorbent Injection System	2011-2012	TBD (If Needed)	N/A	TBD	320	320,000
B05B	B005	Baghouse	2011-2012	TBD	N/A	TBD	320	320,000
BF01	B903	Bagfilter	2011-2012	TBD	N/A	ambient	ambient	1,000
BF02	B904	Bagfilter	2011-2012	TBD	N/A	ambient	ambient	8.33
BF03	B905	Bagfilter	2011-2012	TBD	N/A	ambient	ambient	16.67

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
B05N	NOX					92.38	Vendor Data/NSR Avoidance	TBD
B05B	Total PM	99+	99+			29.14	Vendor Data, NSPS Db, NSR Avoidance	TBD
B05D	HCl					2.26	112(g) Avoidance Limit	TBD
B05D	SO2					198.40	Vendor Data	TBD
BF01	PM	0.01 gr/cf		UNK		0.09	Exit Grain Loading	TBD
BF02	PM	0.01 gr/cf		UNK		7.14E-04	Exit Grain Loading	TBD
BF03	PM	0.01 gr/cf		UNK		1.43E-03	Exit Grain Loading	TBD

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 3.02 – BAGHOUSES & OTHER FILTER COLLECTORS

APCD ID	Filter Surface Area (ft^2)	No. of Bags	Inlet Gas Dew Point Temp. (°F)	Inlet Gas Temp. (°F)	Bag or Filter Material	Pressure Drop (inches of water)	Cleaning Method	Gas Cooling Method	Leak Detection System Type
BF01	TBD	TBD	N/A	ambient	TBD	TBD	TBD	N/A	N/A
BF02	TBD	TBD	N/A	ambient	TBD	TBD	TBD	N/A	N/A
BF03	TBD	TBD	N/A	ambient	TBD	TBD	TBD	N/A	N/A
B05B	TBD	TBD	TBD	320	TBD	TBD	TBD	TBD	TBD

Attach a physical description, dimensions and drawings for each baghouse and any additional information available such as particle size, maintenance schedules, monitoring procedures and breakdown/by-pass procedures. Explain how collected material is disposed of or utilized. Include the attachment in the list on Form 1.00 *General Information*, Item 16

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
B002		ST15	CO	4.64	4.64	20.33	20.33	AP-42 Section 1.4
B002		ST15	NOX	32.87	32.87	143.98	143.98	AP-42 Section 1.4
B002		ST15	SO2	0.12	0.12	0.51	0.51	AP-42 Section 1.4
B002		ST15	VOC	1.06	1.06	4.66	4.66	AP-42 Section 1.4
B002		ST15	Total PM	1.47	1.47	6.44	6.44	AP-42 Section 1.4
B002		ST15	Total PM10	1.47	1.47	6.44	6.44	AP-42 Section 1.4
B002		ST15	Total PM2.5	1.47	1.47	6.44	6.44	AP-42 Section 1.4
B002		ST15	CO2e	23,167	23,167	101,470	101,470	40 CFR 98
B002		ST15	Total HAP	0.37	0.37	1.60	1.60	AP-42 Section 1.4
B005		ST14	CO	93.00	93.00	407.34	407.34	BACT Limit (0.15 lb/MMBtu)
B005	B05N	ST14	NOx	92.38	92.38	404.62	404.62	Annual NSR Avoidance Limit
B005	B05D	ST14	SO2	198.40	198.40	868.99	868.99	NSPS Db
B005		ST14	VOC	6.20	6.20	27.16	27.16	Vendor Data
B005	B05B	ST14	Total PM	29.14	29.14	127.63	127.63	NSPS Db filterable/AP-42 CPM
B005	B05B	ST14	Total PM10	30.38	30.38	133.06	133.06	NSR Avoidance
B005	B05B	ST14	Total PM2.5	24.80	24.80	108.62	108.62	NSR Avoidance
B005		ST14	Pb	0.03	0.03	0.13	0.13	AP-42 Section 1.6
B005	B05D	ST14	H2SO4	3.01	3.01	13.17	13.17	NSR Avoidance
B005	B05D	ST14	HCl	2.26	2.26	9.9	9.9	112(g) Avoidance Limit

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
B005		ST14	CO2e	157,111	157,111	688,147	688,147	Vendor Data/40 CFR 98
B005		ST14	Total HAP	5.43	5.43	22.46	22.46	112(g) Avoidance Limit
B903	BF01	ST89	PM/PM10/PM2.5	0.09	0.09	0.38	0.38	Exit Grain Loading
B904	BF02	ST90	PM/PM10/PM2.5	7.14E-04	7.14E-04	3.13E-03	3.13E-03	Exit Grain Loading
B905	BF03	ST91	PM/PM10/PM2.5	1.43E-03	1.43E-03	6.26E-03	6.26E-03	Exit Grain Loading
CT01			Total PM/PM10	0.74	0.74	3.26	3.26	Engineering Estimate
CT01			PM2.5	0.45	0.45	1.96	1.96	Engineering Estimate

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
B005	No. 3 Biomass Boiler	O2	ppm	continuous
B005	No. 3 Biomass Boiler	CO	lb/MMBtu	continuous
B005	No. 3 Biomass Boiler	NOx	tpy	continuous
B005	No. 3 Biomass Boiler	opacity	%	continuous
B005	No. 3 Biomass Boiler	amount of fuel (per type)	mass units	hourly
B005	No. 3 Biomass Boiler	steam production	lb/hr	hourly
B005	No. 3 Biomass Boiler	natural gas heat input	MMBtu	hourly
B005	No. 3 Biomass Boiler	Baghouse pressure drop	pressure drop units	continuous
B005	No. 3 Biomass Boiler	Baghouse parameters (e.g., conveying systems)	check for proper operation	once per week
N/A	Facility	Electricity Sales	MW-hours	rolling monthly

Comments:
Refer to Appendix E for detailed proposed permit conditions, including monitoring provisions.

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 6.00 – FUGITIVE EMISSION SOURCES

Fugitive Emission Source ID	Description of Source	Emission Reduction Precautions	Pot. Fugitive Emissions	
			Amount (tpy)	Pollutant
A910	Bark Pile and Bark Dumping		1.58E-01	PM
A910	Bark Pile and Bark Dumping		7.47E-02	PM10
A910	Bark Pile and Bark Dumping		1.13E-02	PM2.5

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011, revised August 2011

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
ST14	B005	316	8.5	vertical	62	40	94	320	238,000	320,000
ST15	B002	65	3	vertical	62	40	179.2	370	76,000	76,000
ST89	B903	TBD	TBD	vertical			TBD	ambient	TBD	1,000
ST90	B904	TBD	TBD	vertical			TBD	ambient	TBD	8.33
ST91	B905	TBD	TBD	vertical			TBD	ambient	TBD	16.67

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

Facility Name: Graphic Packaging International, Inc. **Date of Application:** January 2011

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
Refer to Toxics Modeling Analysis to be submitted under separate cover.				☐
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APPENDIX E

TITLE V OPERATING PERMIT MODIFICATION APPLICATION

Proposed Permit Conditions and Updates
GA EPD Title V Database

PROPOSED PERMIT CONDITIONS AND UPDATES

The GPI Macon Mill is currently operating under Title V permit No. 2631-021-0001-V-03-0, effective March 10, 2008. This section of the application identifies and/or requests appropriate changes to the Title V permit conditions as a result of the proposed project. All conditions suggested in this section have a regulatory basis.

In the following sections, new permit conditions or additional language are denoted in **bold** while words being removed are denoted using the ~~strikethrough~~ format. Updated permit condition numbering is also provided herein.

PART 1.0 – SUGGESTED CHANGES TO FACILITY DESCRIPTION

CONDITION 1.3 –PROCESS DESCRIPTION OF MODIFICATION

In Application No. XXXXX, the facility has proposed changes to their steam generation units. The facility will be installing new pieces of equipment, removing other equipment from service, and modifying existing equipment.

- **No. 3 Biomass Boiler (Source Code: B005) – The new bubbling fluidized bed (BFB) boiler will be rated at 620 MMBtu/hr. The boiler will combust biomass, natural gas, and wastewater pretreatment system sludge. Air pollution control equipment includes a baghouse (Control Device ID: B05B) to control PM emissions, selective non-catalytic reduction system (SNCR) (Control Device ID: B05N) to control NO_X emissions. A duct sorbent injection system (DSI) (Control Device ID: B05D) may potentially be employed to reduce HCl emissions.**
- **No. 1 Power Boiler (Source Code: B001) – This existing boiler will be permanently shutdown upon shakedown of the new No. 3 Biomass Boiler.**
- **No. 2 Power Boiler (Source Code: B002) – The coal and fuel oil combustion capabilities of this existing boiler will be permanently removed, at which point natural gas will be combusted exclusively in this boiler. At this time, the No. 2 Power Boiler Scrubber (Control Device ID: B02S) will no longer be utilized.**
- **Addition of a new 40 MW steam turbine generator, fed exclusively by the No. 3 Biomass Boiler, to generate electricity for facility usage and potential sale to the grid. A new cooling tower will be added to support the new turbine.**
- **Addition of new insignificant activities to support the new No. 3 Biomass Boiler: fly ash storage silo, bottom ash and boiler hopper ash storage bin, sorbent storage silo, boiler bed sand storage silo.**

PART 3.0 – SUGGESTED REQUIREMENTS FOR EMISSION UNITS

CONDITION 3.1 – EMISSION UNITS

The table should be amended to address the following additions or changes as proposed herein.

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
B001	No. 1 Power Boiler	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.4.5, 3.4.6, 3.4.7, 4.2.1, 4.2.2, 5.2.2, 5.2.3, 6.1.7, 6.2.2, 6.2.5, 6.2.8**, 7.14.2, 7.14.3, 7.14.4, 7.14.6**	B01S	No. 1 Power Boiler Scrubber
B002	No. 2 Power Boiler	391-3-1-.02(2)(b) 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.4.5, 3.4.6, 3.4.7, 4.2.1, 4.2.2(g), 5.2.2(a-d), 5.2.3(b), 6.1.7(c)(vi), 6.2.2, 6.2.5, 6.2.8**, 7.14.5, 7.14.6**	B02S	No. 2 Power Boiler Scrubber
B005	**No. 3 Biomass Boiler**	**40 CFR 60 Subpart A, Db** **40 CFR 61 Subpart A, E** **391-3-1-.02(2)(a)** **391-3-1-.02(2)(d)** **391-3-1-.02(2)(g)**	**3.3.23, 3.3.28, 3.3.30, 3.3.31, 3.3.32, 3.3.33, 3.3.34, 3.3.35, 3.3.36, 3.4.14, 4.2.1, 4.2.2, 4.2.7, 4.2.8, 4.2.9, 4.2.10, 4.2.11, 5.2.1, 5.2.2, 5.2.3, 5.2.9, 5.2.10, 6.1.7, 6.2.6, 6.2.24, 6.2.25, 6.2.26, 6.2.27, 6.2.28, 6.2.29, 6.2.30, 6.2.31, 6.2.32, 6.2.33, 6.2.34, 6.2.35, 6.2.36, 7.14.1**	**B05B** **B05N** **B05D**	**No. 3 Biomass Boiler Baghouse** **No. 3 Biomass Boiler SNCR (continuous operation not required)** **Duct Sorbent Injection System (optional equipment that will only be installed and used if necessary to meet HCl limit)**
Z901	Unpaved **and Paved** Mill Roads	391-3-1-.02(2)(n)	6.2.14	None	None
A911	**Bark Hog Tower and Hammer Hog**	**391-3-1-.02(2)(b)** **391-3-1-.02(2)(e)** **391-3-1-.02(2)(n)**	**3.4.15, 3.4.16**	**None**	**None**

CONDITION SECTION 3.2 – EQUIPMENT EMISSION CAPS AND OPERATING LIMITS

3.2.1. The Permittee shall not supply more than 219,000 MW-hours of its electric output to any utility power distribution system for sale during any consecutive twelve-month period.
[Avoidance of 40 CFR 72.6(b)(4)]

CONDITION SECTION 3.3 – FEDERAL RULE STANDARDS

3.3.23 The Permittee shall be subject to all applicable provisions of Federal Standard 40 CFR 61 Subpart A – "*General Provisions*" for the No. 2 **and No. 3** Biomass Boiler**s** while combusting mill sludge.
[40 CFR 61 Subpart A]

3.3.28 The Permittee shall be subject to all applicable provisions of Federal Standard 40 CFR 60 Subpart Db – "*Standards of Performance for Industrial-Commercial-Institutional Steam*

Generating Units” for the No. 3 Recovery Boiler **and No. 3 Biomass Boiler** (Source Code**s**: D001, **B005**).
[40 CFR 60 Subpart Db]

3.3.30 The Permittee shall be subject to all applicable provisions of Federal Standard 40 CFR 61 Subpart E – “*National Emission Standards for Hazardous Air Pollutants for Mercury*” for the No. 2 **and No. 3** Biomass Boiler**s** while combusting mill sludge (Source Code**s**: B003, **B005**).
[40 CFR 61 Subpart E]

<u>No. 3 Biomass Boiler (Source Code: B005)</u>

3.3.31 The Permittee shall not discharge or cause the discharge into the atmosphere from the No. 3 Biomass Boiler any gases that contain:

a. Nitrogen oxides (NO_X) in excess of 404.6 tons during any twelve consecutive months.
[NSR Avoidance]

b. Filterable particulate matter (PM) in excess of 0.030 lb/MMBtu on and after the date on which the initial performance test is completed. This standard applies at all times except periods of startup, shutdown, and malfunction.
[40 CFR 60.43b(f)-(h); 391-3-1-.02(2)(d)2(iii) subsumed]]

c. Opacity of which is equal to or greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. This opacity standard shall apply at all times except periods of startup, shutdown, and malfunction.
[40 CFR 60.43b(f)-(g); 391-3-1-.02(2)(d)(3)]

d. Total particulate matter less than 10 microns in diameter (PM_{10}) in excess of 0.049 lb/MMBtu.
[NSR Avoidance]

e. Total particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) in excess of 0.040 lb/MMBtu.
[NSR Avoidance]

f. Sulfuric acid mist (SAM) in excess of 13.2 tons during any twelve consecutive months.
[NSR Avoidance]

g. Hydrochloric Acid (HCl) in excess of 9.9 tons during any twelve consecutive months.
[112(g) Case-by-case MACT avoidance]

h. Any single hazardous air pollutant (HAP) which is listed in Section 112 of the Clean Air Act in an amount equal to or exceeding 10 tons during any twelve months, or any combination of such listed pollutants in an amount equal to or exceeding 25 tons during any twelve consecutive months.
[112(g) Case-by-case MACT avoidance]

i. **Carbon Monoxide (CO) in excess of 0.15 lb/MMBtu (30-day rolling average), excluding periods of startup, shutdown, and malfunction.**
[40 CFR 52.21(j)]

j. **Carbon monoxide (CO) in excess of 407.3 tons during any twelve consecutive months.**
[40 CFR 52.21(j)]

3.3.32 **The annual capacity factor for fossil fuel fired in the No. 3 Biomass Boiler must be 10 percent or less. The annual capacity factor is the ratio between the actual heat input to a steam generating unit from fossil fuel during a calendar year and the potential heat input to the boiler had it been operated 8,760 hours during a calendar year at the maximum steady state design heat input capacity.**
[40 CFR 60.41b, 40 CFR 60.44b(c)]

3.3.33 **The Permittee shall not discharge or cause the discharge into the atmosphere from the No. 3 Biomass Boiler any gases that contain mercury in excess of 7.1 pounds per 24-hour period while burning mill sludge.**
[40 CFR 61.52(b)]

3.3.34 **The Permittee shall fire only natural gas, mill sludge, clean cellulosic biomass, and/or cellulosic biomass (virgin wood) in the No. 3 Biomass Boiler. This unit is not intended to be classified as an Industrial Solid Waste Incineration unit and will not burn solid waste as defined under 40 CFR 241.**

Clean cellulosic biomass means those residuals that are akin to traditional cellulosic biomass such as forest-derived biomass (e.g., green wood, forest thinnings, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials), corn stover and other biomass crops used specifically for energy production (e.g., energy cane, other fast growing grasses), bagasse and other crop residues (e.g., peanut shells), wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, clean biomass from land clearing operations, and clean construction and demolition wood. These fuels are not secondary materials or solid wastes unless discarded. Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials.
[40 CFR 52.21; Definition from 40 CFR 241.2; Avoidance of 40 CFR 60 Subpart CCCC]

3.3.35 **The Permittee shall not exceed 249 MMBtu/hr heat input from natural gas firing on the No. 3 Biomass Boiler.**
[40 CFR NSPS Subpart Da avoidance; 391-3-1-.02(2)(d)]

3.3.36 **The Permittee shall not combust natural gas with mill sludge alone in the No. 3 Biomass Boiler.**
[40 CFR 60.42b(k)(2)]

CONDITION SECTION 3.4 – SIP RULE STANDARDS

<u>No. 3 Biomass Boiler (Source Code: B005)</u>

3.4.14 The Permittee shall not burn fuel containing more than 3% sulfur, by weight, in the No. 3 Biomass Boiler.
[391-3-1-.02(2)(g)2]

<u>Bark Hog Tower and Hammer Hog (Source Code: A911)</u>

3.4.15 The Permittee shall not cause, let, suffer, permit or allow emissions from the Bark Hog Tower and Hammer Hog, the opacity of which is equal to or great than forty (40) percent.
[391-3-1-.02(2)(b)1]

3.4.16 The Permittee shall not cause, let, permit, suffer or allow the rate of emission from the Bark Hog Tower and Hammer Hog, particulate matter in total quantities equal to or exceeding the allowable rates calculated using the following equation:
[391-3-1-.02(2)(e)1(i)]

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

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

E = emission rate in pounds per hour
P = process input weight rate in tons per hour

PART 4.0 – SUGGESTED REQUIREMENTS FOR TESTING

CONDITION SECTION 4.1 – GENERAL TESTING REQUIREMENTS

4.1.3 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division’s Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, 3.4 and 3.5 are as follows:

<u>Additional Test Methods</u>

z. Method 26 or Method 26A shall be used to determine hydrogen chloride (HCl) concentration.

aa. Method 101 in Appendix B of 40 CFR Part 61 shall be used to determine mill sludge mercury (Hg) concentration.

ab. Method 5 or Method 201 or Method 201A in conjunction with Method 202 shall be used to determine total PM_{10} concentration.

ac. Other Test Method 027 (OTM-27) in conjunction with Other Test Method 028 (OTM-028) shall be used to determine total $PM_{2.5}$ concentration.

ad. Method 8 shall be used for the determination of sulfuric acid mist emissions.

ae. ASTM E871 or E870, or approved equivalent shall be used to determine biomass moisture content.

af. ASTM E711 or approved equivalent shall be used to determine the heat content of biomass.

ag. ASTM E775 or approved equivalent shall be used to determine biomass sulfur content.

CONDITION SECTION 4.2 – SPECIFIC TESTING REQUIREMENTS

4.2.1 The Permittee shall perform performance tests for the following specified equipment and pollutants:
[391-3-1-.02(6)(b)1]

Equipment	Pollutants
Nos. 1 and 2 Power Boilers	Particulate Matter (PM)
No. 2 Biomass Boiler	Particulate Matter (PM) Nitrogen Oxides (NO_X)
No. 3 Biomass Boiler	**Particulate Matter (PM)** **Total PM_{10}** **Total $PM_{2.5}$** **Hydrogen Chloride (HCl)** **Sulfuric Acid Mist (SAM)**
No. 3 Recovery Boiler	Particulate Matter (PM) Nitrogen Oxides (NO_X) Total Reduced Sulfur (TRS) Sulfur Dioxide (SO_2)
No. 3 Smelt Dissolving Tank	Particulate Matter (PM) Total Reduced Sulfur
Nos. 1 and 2 Lime Kilns	Particulate Matter (PM) Sulfur Dioxide (SO_2) Nitrogen Oxides (NO_X) Total Reduced Sulfur (TRS)

4.2.2 The Permittee shall conduct performance tests as specified by the following table and criteria unless otherwise specified by the Division:
[391-3-1-.02(2)(a)(10)]

Equipment	Pollutants
Nos. 1 and 2 Power Boilers	PM - biennial
No. 2 Biomass Boiler	PM – annual NOx – annual
No. 3 Biomass Boiler	**PM – annual** **Total PM_{10} – annual** **Total $PM_{2.5}$ – annual**
No. 3 Recovery Boiler	PM - annual TRS – biennial NOx – biennial SO_2 - annual
No. 3 Smelt Dissolving Tank	PM - annual TRS - biennial
Nos. 1 and 2 Lime Kilns	PM - annual SO_2 – annual NO_x – semi-annual TRS - biennial

h. The Permittee must conduct a sludge test within 90 days of the startup of the No. 3 Biomass Boiler (Source Code: B005) using Method 105 (Appendix B to Part 61) to determine the maximum amount of mercury (grams) in a 24-hour period. A total of three composite samples shall be obtained within an operating period of 24 hours. When the 24-hour operating period is not continuous, the total sampling period shall not exceed 72 hours after the first grab sample is obtained.
[40 CFR 61.54]

<u>40 CFR 60 Subpart Db Testing Requirements – No. 3. Biomass Boiler</u>

4.2.7 At least 60 days prior to the initial compliance demonstration, the Permittee shall develop and submit a site-specific fuel analysis plan to the Division for review and approval. The plan shall be used to conduct the weekly SO_2 fuel analysis for the No. 3 Biomass Boiler and shall be developed in accordance with 40 CFR 60.49b(r). The Permittee may petition to reduce the sampling frequency from weekly to monthly or quarterly.
[40 CFR 60.45b(k) and 60.49b(r)]

4.2.8 To determine compliance with the PM emission limit of Condition 3.3.31.b, the Permittee shall conduct an initial performance test on the No. 3 Biomass Boiler within 60 days after achieving the maximum production rate but no later than 180 days after initial startup of the boiler.
[40 CFR 60.46b(d)]

<u>NSR Avoidance Testing Requirements – No. 3. Biomass Boiler</u>

4.2.9 Within 180 days after initial startup, the Permittee shall conduct performance evaluations of the NO_X CEMS required by Condition 5.2.1.c.
[391-3-1-.02(6)(b)1]

4.2.10 Within 180 days of the initial startup of the No. 3 Biomass Boiler, the Permittee shall conduct performance testing for total PM_{10} and total $PM_{2.5}$ using the methods specified in Condition 4.1.3 to verify compliance with the emission limits of Condition 3.3.31.d and e.
[Avoidance of 52.21 and PM2.5 Nonattainment NSR, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

a. Data from these tests shall be used to establish the pressure drop range required by Condition 5.2.2.j. Data from a previously approved performance test which demonstrated compliance with the applicable emission limit may be used to establish the operational parameters in lieu of the most recent performance tests as long as such previous performance test is representative of current operations of the emission unit and was conducted during the five years prior to the most recent performance test.

b. The Permittee shall submit with the quarterly report required by Condition No. 6.1.4 a list of all the current operational parameters established in accordance with this condition for the purpose of reporting under Condition No. 6.1.7.c.

4.2.11 Within 180 days of the initial startup of the No. 3 Biomass Boiler, the Permittee shall conduct performance testing for SAM and HCl emissions using the methods specified in Condition 4.1.3. Based on the data collected through the performance testing, the Permittee shall use the results as an approved emission factor (in lb/MMBtu) for the SAM and HCl, respectively, in Conditions 6.2.27 and 6.2.29.
[391-3-1-.02(6)(b)(1)]

PART 5.0 – SUGGESTED REQUIREMENTS FOR MONITORING

CONDITION SECTION 5.2 – SPECIFIC MONITORING REQUIREMENTS

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

c. Opacity, O_2, CO, and NO_X from the No. 3 Biomass Boiler.
[40 CFR 60.48b(a), 40 CFR 52.21, NSR Avoidance]

5.2.2 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

j. Pressure drop across baghouse B05B.
[Avoidance of 40 CFR 52.21]

k. Steam production, recorded hourly, of the No. 3 Biomass Boiler.

[391-3-1-.02(6)(b)1]

l. **Heat input from natural gas, recorded hourly, to the No. 3 Biomass Boiler.**
[40 CFR 60 Subpart Da Avoidance and 391-3-1-.02(6)(b)1]

5.2.3 The Permittee shall install, calibrate, maintain, and operate monitoring devices for the measurement of the indicated parameters on the following equipment. Data shall be recorded at the frequency specified below. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

k. **Amount and type of fuels fired in the No. 3 Biomass Boiler. Data shall be recorded once per hour of operation.**
[40 CFR 60.49b(d) and 391-3-1-.02(6)(b)1]

5.2.9. Once per year, the Permittee shall analyze a gross sample of mill wastewater pretreatment sludge to be combusted in the No. 3 Biomass Boiler for mercury content if the mercury level from the initial sludge sampling per Condition 4.2.2.h exceeds 3.5 pounds per 24-hour period.
[40 CFR 61.55(a)]

5.2.10 Once per week or in accordance with the approved site-specific monitoring plan developed per Condition 4.2.7, the Permittee shall analyze a gross sample of the fuel to be combusted in the No. 3 Biomass Boiler for SO_2 potential emissions (in lb/MMBtu).
[40 CFR 60.45b(k) and 60.49b(r)]

5.2.11 Within 60 days of the startup of the No. 3 Biomass Boiler, the Permittee shall develop and implement a Preventive Maintenance Program for baghouse B05B to assure that the provisions of condition 8.17.1 are met. The program shall be subject to review and, if necessary to assure compliance, modification by the Division and shall include the pressure drop ranges that indicate proper operation for the baghouse. At a minimum, the following operation and maintenance checks shall be made on at least a weekly basis, and a record of the findings and corrective actions taken shall be kept in a maintenance log:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. **Record the pressure drop across the baghouse and ensure that it is within the appropriate range.**

b. **For baghouses equipped with compressed air cleaning systems, check the system for proper operation. This may include checking for low pressure, leaks, proper lubrication, and proper operation of timer and valves.**

c. **For baghouses equipped with reverse air cleaning systems, check the system for proper operation. This may include checking damper, bypass, and isolation valves for proper operation.**

d. **For baghouses equipped with shaker cleaning systems, check the system for proper operation. This may include checking shaker mechanism for loose or worn bearings, drive components, mounting; proper operation of outlet/isolation valves; proper lubrication.**

e. **Check dust collector hoppers and conveying systems for proper operation**.

PART 6.0 – SUGGESTED REQUIREMENTS FOR RECORD KEEPING AND REPORTING

CONDITION SECTION 6.1 – GENERAL RECORD KEEPING AND REPORTING

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined or stated to be, excess emissions by an applicable requirement)

No. 3 Biomass Boiler (Source Code: B005)

viii. **Any 12-month rolling period during which the NO_X emissions measured and recorded in accordance with Condition 5.2.1.c and converted to tons per year per Condition 6.2.25, are in excess of the limit established by Condition 3.3.31.a.**
[NSR Avoidance]

ix. **Any six-minute period (excluding periods of startup, shutdown, or malfunctions) during which the average opacity measured and recorded in accordance with Condition 5.2.1.c exceeds 20%, except for one 6-minute period per hour of not more than 27 percent.**
[40 CFR 60.43b(f), 391-3-1-.02(2)(d)(3)]

x. **Any 30-day rolling period during which the average CO emissions (excluding startup, shutdown, and malfunction periods) measured and recorded in accordance with Condition 5.2.1.c are in excess of the emission limit established by Condition 3.3.31.i.**
[40 CFR 52.21(j)]

xi. **Any 12-month rolling period during which the CO emissions measured and recorded in accordance with Condition 5.2.1.c and converted to tons per**

year per Condition 6.2.36, are in excess of the limit established by Condition 3.3.31.j.
[40 CFR 52.21(j)]

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

<u>Fuel</u>

iii. Any time of process operation during which the fuel ~~oil~~ burned in the following equipment does not meet the limits in the referenced conditions:
[391-3-1-.02(2)(g)]

(D) No. 3 Biomass Boiler does not meet the requirements per Conditions 3.3.34 or 3.4.14.

<u>No. 3 Biomass Boiler (Source Code: B005)</u>

ix. Any 12-month rolling period during which the Permittee sells more than 219,000 MW-hours of its electric output to any utility power distribution system.
[Avoidance of 40 CFR 72.6(b)(4)]

x. Any time of process operation during which the mill wastewater sludge fired in the No. 3 Biomass Boiler contains mercury in excess of 7.1 pounds per 24-hour period as determined by sludge sampling per Condition 5.2.9.
[40 CFR 61.52(b), 40 CFR 61.55(a)]

xi. Any time of process operation during which natural gas and mill sludge are combusted in the No. 3 Biomass Boiler without the presence of biomass.
[40 CFR 60.42b(k)(2)]

xii. Any time of process operation during which natural gas heat input in the No. 3 Biomass Boiler exceeds 249 MMBtu/hr.
[40 CFR 60 Subpart Da Avoidance; 391-3-1-.02(2)(d)]

xiii. Any twelve consecutive month period in which the rolling sum of sulfuric acid mist (SAM) emissions from the No. 3 Biomass Boiler calculated in accordance with Condition 6.2.27 are in excess the limit established by Condition 3.3.31.f.
[NSR Avoidance]

xiv. Any twelve consecutive month period in which the rolling sum of hydrogen chloride (HCl) emissions from the No. 3 Biomass Boiler calculated in accordance with Condition 6.2.29 are in excess the limit established by Condition 3.3.31.g.

[112(g) Case-by-case MACT avoidance]

xv. **Any twelve consecutive month period in which the rolling sum of any individual HAP or total HAP emissions from the No. 3 Biomass Boiler calculated in accordance with Condition 6.2.31 are in excess of the limit established by Condition 3.3.31.h.**
[112(g) Case-by-case MACT avoidance]

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

No. 3 Biomass Boiler (Source Code: B005)

xi. **Any consecutive twelve-month period during which the annual capacity factor for fossil fuel fired in the No. 3 Biomass Boiler is greater than 10 percent.**
[40 CFR 60.44b(c)]

xii. **Any 3-hour period during which the pressure drop of Baghouse B05B exceeds the parameters established in accordance with Condition 4.2.10.**

xiii. **Any weekly inspection of Baghouse B05B as required by Condition 5.2.11 revealing a problem that is not resolved in accordance with the Preventative Maintenance Program.**

d. In addition to the excess emissions, exceedances and excursions specified above, the following should also be included with the report required in Condition 6.1.4:

vi. **A report of the 12-month rolling total for the electric output from the facility to any utility power distribution system for sale, calculated in accordance with Condition 6.2.34 for each month in the reporting period.**
[Avoidance of 40 CFR 72.6(b)(4)]

vii. **The annual capacity factor for fossil fuel in the No. 3 Biomass Boiler for the past twelve consecutive months. The annual capacity factor shall be recorded at the end of each month and determined in accordance with Condition 3.3.32.**
[40 CFR 60.49b(d)]

viii. **Each month's twelve-month rolling total NO_X, CO, H_2SO_4, HCl, and total HAP emissions from the No. 3 Biomass Boiler as calculated by Conditions 6.2.25, 6.2.27, 6.2.29, 6.2.31, and 6.2.36.**
[NSR Avoidance, 112(g) Case-by-case MACT Avoidance, 40 CFR 52.21(j)]

CONDITION SECTION 6.2 – SPECIFIC RECORD KEEPING AND REPORTING

Fuel

6.2.6 The Permittee shall record and maintain records of the amounts of fuel combusted during each day for the No. 3 Recovery Boiler **and the No. 3 Biomass Boiler** and calculate the annual capacity factor for **each source for** ~~fuel oil and natural gas~~ **fossil fuels**. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.
[40 CFR 60 Subpart Db]

Woodyard Area Chip and Fines Transfer and Coal Storage System and ~~Un~~**P**aved Roads

No. 3 Biomass Boiler (Source Code: B005)

6.2.24 The Permittee shall verify that each supplier provides an annual certification that shipments of biomass fuel for combustion complies with the requirements of Condition 3.3.34. The Permittee shall retain records on site for a period of at least five years in a format suitable for inspection.
[391-3-1-.02(6)(b)1]

6.2.25 The Permittee shall use the NO_X emissions data measured and recorded in accordance with Condition 5.2.1.c and the fuel firing rates measured and recorded in accordance with Conditions 5.2.3.l in order to calculate monthly NO_X emissions. The monthly emissions shall be used to calculate the twelve-month rolling total NO_X emissions. Each month's twelve-month rolling total shall be the sum of the current month's emissions plus the previous eleven months' emissions.
[391-3-1-.02(6)(b)1]

6.2.26 The Permittee shall notify the Division in writing if emissions of NO_X exceed 33.7 tons from the No. 3 Biomass Boiler during any month and/or the emissions of NO_X exceed 404.6 tons from the No. 3 Biomass Boiler during any twelve consecutive months. This notification shall be postmarked by the fifteenth day of the following month and shall include an explanation of how the Permittee intends to maintain future compliance with the emission limit in Condition No. 3.3.31.a. All calculations should be kept as part of the monthly record. These records shall be kept available for inspection or submittal for five years from the date of record.
[391-3-1-.02(6)(b)1]

6.2.27 The Permittee shall use the following equation to calculate the monthly SAM emissions from the No. 3 Biomass Boiler. The monthly emissions shall be used to calculate the twelve-month rolling total SAM emissions. Each month's twelve-month rolling total shall be the sum of the current month's emissions plus the previous eleven months' emissions.
[391-3-1-.02(6)(b)1]

Calculation of monthly SAM emissions from the boiler.

SAM = (EF) (R) / (2000 lb/ton)

Where,

SAM = monthly SAM emissions from the boiler in tons per month

EF = tested emission factor in lb/lb steam from stack testing results in Condition 4.2.11 and approved by the Division.

R = measured steam production (lb steam/month) for the boiler monitored and recorded per Condition 5.2.2.k

6.2.28 The Permittee shall notify the Division in writing if emissions of SAM exceed 1.1 tons from the No. 3 Biomass Boiler during any month and/or the emissions of SAM exceed 13.2 tons from the No. 3 Biomass Boiler during any twelve consecutive months. This notification shall be postmarked by the fifteenth day of the following month and shall include an explanation of how the Permittee intends to maintain future compliance with the emission limit in Condition No. 3.3.31.f. All calculations should be kept as part of the monthly record. These records shall be kept available for inspection or submittal for five years from the date of record.
[391-3-1-.02(6)(b)1]

6.2.29 The Permittee shall use the following equation to calculate the monthly HCl emissions from the No. 3 Biomass Boiler. The monthly emissions shall be used to calculate the twelve-month rolling total HCl emissions. Each month's twelve-month rolling total shall be the sum of the current month's emissions plus the previous eleven months' emissions.
[391-3-1-.02(6)(b)1]

Calculation of monthly HCl emissions from the boiler.

HCl = (EF) (R_b) / (2000 lb/ton)

Where,

HCl = monthly HCl emissions from the boiler in tons per month

EF = tested emission factor in lb/lb steam from stack testing results in Condition 4.2.11 and approved by the Division.

R_b = measured steam production (lb steam/month) for the boiler monitored and recorded per Condition 5.2.2.k

6.2.30 The Permittee shall notify the Division in writing if emissions of HCl exceed 0.83 tons from the No. 3 Biomass Boiler during any month and/or the emissions of HCl exceed

10 tons from the No. 3 Biomass Boiler during any twelve consecutive months. This notification shall be postmarked by the fifteenth day of the following month and shall include an explanation of how the Permittee intends to maintain future compliance with the emission limit in Condition No. 3.3.31.g. All calculations should be kept as part of the monthly record. These records shall be kept available for inspection or submittal for five years from the date of record.
[391-3-1-.02(6)(b)1]

6.2.31 The Permittee shall use the following equations to calculate the monthly total HAP emissions from the No. 3 Biomass Boiler. The monthly emissions shall be used to calculate the twelve-month rolling total HAP emissions. Each month's twelve-month rolling total shall be the sum of the current month's emissions plus the previous eleven months' emissions.
[391-3-1-.02(6)(b)1]

a. Calculation of monthly individual HAP emissions (other than HCl) from the boiler.

$$HAP_i = (EF_{ib})\ (R_b) / (2000\ lb/ton) + (EF_{ing})\ (R_{ng}) / (2000\ lb/ton)$$

Where,

HAP_i = monthly individual emissions from the boiler in tons per month

EF_i = biomass emission factor for HAP_i in lb/lb steam as approved by the Division in Appendix B of the Permit Application No. XXXXX (Volume I) dated January 2011 and revised August 2011.

R_b = measured steam production (lb steam/month) for the boiler – (R_{ng} * 1,024 MMBtu/ MMScf heating value * 717 lb steam/MMBtu gas)

EF_{ing} = natural gas emission factor for HAP_i in lb/MMscf as approved by the Division in Appendix B of the Permit Application No. XXXXX (Volume I) dated January 2011 and revised August 2011.

R_{ng} = measured natural gas usage (MMscf/month) for the boiler

b. Total HAP emitted each month shall be calculated by adding the individual HAP emissions from Condition 6.2.31a and the total HCl emissions from Condition 6.2.29 during the month.

6.2.32 The Permittee shall notify the Division in writing if emissions of total HAP exceed 2.08 tons from the No. 3 Biomass Boiler during any month and/or the emissions of total HAP exceed 25 tons from the No. 3 Biomass Boiler during any twelve consecutive months. This notification shall be postmarked by the fifteenth day of the following month and shall include an explanation of how the Permittee intends to maintain

future compliance with the emission limit in Condition No. 3.3.31.h. All calculations should be kept as part of the monthly record. These records shall be kept available for inspection or submittal for five years from the date of record.
[391-3-1-.02(6)(b)1]

6.2.33 The Permittee shall record and maintain monthly records of any utility power sold in accordance with the limit in Condition 3.2.1. The facility shall use the records to calculate 12-month rolling totals of MW-hours of electrical output supplied to any utility power sold from the facility.
[Avoidance of 40 CFR 72.6(b)(4)]

6.2.34 The Permittee shall provide all notifications as required per 40 CFR 60.7 and 40 CFR 61.09 by the dates specified. Specifically, the Permittee shall provide notification of:

a. The anticipated date of initial startup of the No. 3 Biomass Boiler not more than 60 days nor less than 30 days before that date.

b. The actual date of initial startup of the No. 3 Biomass Boiler postmarked within 15 days after such date.

c. The anticipated date of performance testing, including COMS performance evaluations, at least 60 days before the performance test is scheduled to begin.

6.2.35 The Permittee shall use the CO emissions data measured and recorded in accordance with Condition 5.2.1.c and the fuel firing rates measured and recorded in accordance with Conditions 5.2.3.l in order to calculate monthly CO emissions. The monthly emissions shall be used to calculate the twelve-month rolling total CO emissions. Each month's twelve-month rolling total shall be the sum of the current month's emissions plus the previous eleven months' emissions.
[391-3-1-.02(6)(b)1]

CONDITION SECTION 7.14 – SPECIFIC CONDITIONS ASSOCIATED WITH THIS AMENDMENT

7.14.1 The following new and modified conditions shall become effective upon startup of each new unit listed below. The associated testing, monitoring, record keeping, and reporting requirements shall also become effective upon startup of each respective piece of equipment.
[40 CFR 70.6(a)(3)(i) and 391-3-1-.02(6)(b)(1)]

a. No. 3. Biomass Boiler (Source Code: B005) – 3.3.23, 3.3.28, 3.3.30, 3.3.31, 3.3.32, 3.3.33, 3.3.34, 3.3.35, 3.3.36, 3.4.14, 4.2.1, 4.2.2, 4.2.7, 4.2.8, 4.2.9, 4.2.10, 4.2.11, 5.2.1, 5.2.2, 5.2.3, 5.2.9, 5.2.10, 6.1.7, 6.2.6, 6.2.24, 6.2.25, 6.2.26, 6.2.27, 6.2.28, 6.2.29, 6.2.30, 6.2.31, 6.2.32, 6.2.33, 6.2.34, 6.2.35, 6.2.36

7.14.2 Upon the date identified in the notification required by Condition 7.14.6.a, the following associated emission limits, testing, monitoring, record keeping, and reporting requirements for each piece of equipment shall become null and void.
[40 CFR 70.6(a)(3)(i) and 391-3-1-.02(6)(b)(1)]

a. No. 1 Power Boiler (Source Code: B001) - 4.2.1, 4.2.2, 5.2.2(a), 5.2.3(b), 6.1.7(c)(vi), 6.2.2, 6.2.5, 6.2.8. Removal of Control Device ID No. B01S

7.14.3 Upon the date identified in the notification required by Condition 7.14.6.a, the No. 1 Power Boiler shall combust only natural gas.
[40 CFR 70.6(a)(3)(i) and 391-3-1-.02(6)(b)(1)]

7.14.4 Once each of the following equipment is permanently shutdown, all associated emission limits, testing, monitoring, record keeping, and reporting requirements for each piece of equipment shall become null and void.
[40 CFR 70.6(a)(3)(i) and 391-3-1-.02(6)(b)(1)]

a. No. 1 Power Boiler (Source Code: B001)

7.14.5 Upon the date identified in the notification required by Condition 7.14.6.c, the following associated emission limits, testing, monitoring, record keeping, and reporting requirements for each piece of equipment shall become null and void.
[40 CFR 70.6(a)(3)(i) and 391-3-1-.02(6)(b)(1)]

a. No. 2 Power Boiler (Source Code: B002) – 4.2.1, 4.2.2, 5.2.2(a), 5.2.3(b), 6.1.7(c)(vi), 6.2.2, 6.2.5, 6.2.8. Removal of Control Device ID No. B02S.

7.14.6 The Permittee shall furnish the Division written notification within 60 days as follows:
[391-3-1-.02(6)(b)(1)]

a. Notification of the date the No. 1 Power Boiler is disconnected from Stack ST14.

b. Notification of the date the No. 1 Power Boiler ceased operation and was permanently shutdown.

c. Notification of the date that coal and fuel oil combustion capabilities were permanently removed from the No. 2 Power Boiler.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Maintenance, Cleaning, and Housekeeping	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	8

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	3
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	3
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	3
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	Numerous
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	Numerous

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
Aqueous Ammonia Day Tank (250 gallons, <20% ammonia)	1
Bark Pile and Bark Dumping	2
Boiler Ash Pile Loading and Removal	1
Boiler Fly Ash Silo	1
Boiler Bottom Ash and Boiler Hopper Ash Storage Bin	1
Boiler Bed Sand Silo	1
Boiler Sorbent Silo	1
Boilout Tank (205,800 gallons)	1
Chemicals Additives Tanks (<1,000 gallons)	7
Chemicals Additives Tanks (>10,000 gallons)	6
Chemicals Additives Tanks (1,000 – 2,000 gallons)	1
Chemicals Additives Tanks (2,000 – 4,000 gallons)	7
Chemicals Additives Tanks (4,000 - 10,000 gallons)	5
Chemi-Defoamer	1
Chip Storage	1

Chip Pile/Chip Truck Dump	1
Cooling Tower	7
Stacker/Reclaimer System	1
Dregs Washer and Filter	1
Effluent Defoamer	1
Fresh Lime Silo	1
Green Liquor Storage Tank (88,000 gallons)	1
Green Liquor Surge Tank (322,5000 gallons)	1
Lime Unloading from Railcars	1
Reburned Lime Silo	1
Reburned Lime Unloading and Conveying	1
Soda Ash Hoppers	2

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch
Major Source Operating Permit Application

4244 International Parkway
Suite 120
Atlanta, Georgia 30354-3906
404-363-7000

Certifications and Signatures

Facility Name: Graphic Packaging International, Inc.

Project Name: No. 3 Biomass Boiler PSD Permit Application

AIRS Number: 130210001

Submittal File Name: 130210001_20110809.mdb

COMPUTER DISK VIRUS EXAMINATION CERTIFICATION:
I certify that, to the best of my knowledge, the completed electronic application disk has been inspected and found free of any known viruses.

Signature: [signature] Date: 8/10/2011

Name (print): Katherine A. Scott

Offical Title: Senior Consultant

SOFTWARE USAGE CERTIFICATION:
I certify that the software used to complete the Georgia Title V application was used as provided by the Georgia Environmental Protection Division, Air Protection Branch and was unaltered in any way. I understand that the submission of a Title V (Part 70) application completed using any altered version of the provided software constitutes the submission of an incomplete application and that such action may be subject to enforcement by the Georgia Air Protection Branch and/or the US EPA.

CERTIFICATION OF COMPLIANCE:
Except as stated on the Compliance Plan For a Non-Compliant Emission Unit or Group form of this application, I hereby certify that this facility is in compliance with all applicable requirements effective as of the date of this certification and will continue to comply with such requirements. For applicable requirements promulgated as of the date of this certification, that will become effective during the permit term, I further certify that, except as stated on the Compliance Plan For a Non-Compliant Emission Unit or Group form of this application, this facility will comply with such requirements and will continue to comply with such requirements.

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this application and all of its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Unless otherwise required by the Director, compliance certifications will be submitted to the Director at least annually.

SIGNATURE OF RESPONSIBLE OFFICIAL:

Signature: [signature] Date: 8/9/11

Name (print): Steven G. Hanson

Offical Title: Resident Manager

Address: 100 Graphic Packaging Int'l Way
Macon, GA 31206

Notary Public Certification of Responsible Official's Signature:

Signature of Notary Public: Shelia M. Sanders

My Commission expires 11/25/12

Printed on: 8/9/2011