Prevention of Significant Air Quality Deterioration Review

Final Determination

December 9, 2010

Facility Name: Warren County Biomass Energy Facility
City: Warrenton
County: Warren
AIRS Number: 04-13-301-00016
Application Number: 19121
Date Application Received: August 6, 2009

State of Georgia
Department of Natural Resources
Environmental Protection Division
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BACKGROUND

On October 14, 2009, Warren County Biomass Energy Facility submitted an application for an air quality permit to construct and operate a 100-megawatt (MW) biomass-fueled electric generating facility. The facility is located at 612 East Warrenton Road in Warrenton, Warren County. The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 million British Thermal Unit per hour (MMBtu/hr), two fire water pump emergency engines; a raw material handling and storage area; a sorbent storage silo; a boiler bed sand silo, a sand day hopper; a fly ash silo, a bottom ash area; storage tanks; and a four-cell mechanical draft wet cooling tower.

On October 8, 2010, the Division issued a Preliminary Determination stating that the facility described in Application No. 19121 should be approved. The Preliminary Determination contained a draft Air Quality Permit for the construction and operation of the modified equipment.

The Division requested that Warren County Biomass Energy Facility place a public notice in a newspaper of general circulation in the area of the proposed facility notifying the public of the proposed construction and providing the opportunity for written public comment. Such public notice was placed in *The Warrenton Clipper* (legal organ for Warren County) on October 15, 2010. The public comment period expired on November 19, 2010.

During the comment period, comments were received from U.S. EPA Region IV, Warren County Biomass Energy Facility, State of Florida, and general public. The comments are listed below along with the Division's responses and a discussion of any changes made to the final permit.

A copy of the final permit is included in Appendix A. A copy of written comments received during the public comment period is provided in Appendix B.

U.S. EPA REGION 4 COMMENTS

Comments were received from Gregg Worley, Chief of the Air Permits Section, U.S. EPA Region 4, by letter on November 22, 2010. The comments are typed, verbatim, below and were the result of reviews by James Purvis of U.S. EPA Region 4.

Comment 1:

The draft permit establishes a BACT limitation of 0.28 lbs/MMBtu of NOx on a one hour average. The preliminary determination, however, does not provide the basis for this limit or the methodology used to determine that emission level as BACT. Please provide additional explanation and detail.

EPD Response:

The NOx limit of 0.28 lb/MMBtu (on a 1-hour average) is not a BACT limit. EPD added this modeling limit to ensure the facility complies with the new 1-hour National Ambient Air Quality Standard (NAAQS) for NO_2.

Based on facility's request, EPD has decided to modify this limit from 0.28 lb/MMBtu to 372.1 lb/hr. The 372.1 lb/hr emissions rate comes from EPD's modeling review conducted for the NO_2 1-hour standard. Please refer to EPD's Response to Facility Comment 10.

Comment 2:

The draft permit establishes a BACT limitation of 0.95 lbs/MMBtu of SO_2 on a one hour average. The preliminary determination, however, does not provide the basis for this limit or the methodology used to determine that emission level as BACT. Please provide additional explanation and detail.

EPD Response:

The SO_2 limit of 0.095 lb/MMBtu (on a 1-hour average) is not a BACT limit. EPD added this modeling limit to ensure the facility complies with the new 1-hour National Ambient Air Quality Standard (NAAQS) for SO_2.

Based on facility's request, EPD has decided to modify this limit from 0.095 lb/MMBtu to 132.9 lb/hr. The 132.9 lb/hr emissions rate comes from EPD's modeling review conducted for the SO_2 1-hour standard. Please refer to EPD's Response to Facility Comment 10.

Comment 3:

EPA is aware of a permit being issued that did not appear to be considered during the BACT determination process and the drafting of the related permit conditions, which are currently under review. This is most likely because at the time, the facility information would not have been found in a search permitted sources. Gainesville Renewable Energy Center (GREC) is a same-sized biomass facility in the state of Florida, which has agreed to install Selective Catalytic Reduction as a control technology and has accepted more stringent emission limits, specifically for the pollutants SO_2 and NOx. This facility will also be using continuous monitoring of Hazardous Air Pollutant (HAP) emissions. EPA recommends the State revisit the BACT determination and emission limits.

The State should provide all details and rational as to how the proposed facility is unique in comparison to GREC, should the analysis show that for the proposed project, it is infeasible to meet similar limits and conditions to those taken in the GREC permit.

EPD Response:

The facility has indicated in the permit application that the Tail End SCR/RSCR works by reheating the flue gas to the necessary temperatures for the ammonia and NOx to react to form nitrogen and water, this reheating process of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. In addition, this technology has been demonstrated on small wood-fired stroke boilers. The facility has indicated that energy impacts include combustion of 302,400 gallons per year of biodiesel to reheat the flue gas as well as 1.4 MW of lost capacity. Finally, the facility indicated that the annualized costs for a tail end SCR are estimated to be $12,764 per ton of NOx removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

The facility has indicated that the Hot End/High Dust SCR systems have been permitted and installed on boilers firing natural gas, fuel oil, and coal. The primary issue associated with a hot end SCR involves the presence of other alkali metals and trace elements in the particulate matter of the flue gas that can chemically damage the catalyst, gradually neutralizing its ability to reduce NOx. The facility has indicated that energy impacts include 0.7 MW of lost capacity. Finally, the facility indicated that the annualized costs for a hot end SCR are estimated to be $10,877 per ton of NOx removed (refer to Appendix D of facility application for more information on the energy and economic impacts).

In addition, after reviewing Gainesville Renewable Energy Center (GREC) project, the preliminary determination indicated that the NOx limit of 0.070 lbs/MMBtu on 24-hour basis, which is proposed by GREC is not a BACT limit. GREC voluntarily decided to accept this limit and to install an SCR system to control NOx emissions. Both the proposed control technology and emissions limit does not come from a BACT review. Based on EPD's review, SNCR is the appropriate NOx BACT control technology and 0.10 lbs/MMBtu is the correct BACT NOx emissions limit for a bubbling fluidized bed (BFB) Biomass Boiler.

EPD's review of GREC project shows that the facility has proposed a SO_2 limit of 0.029 lbs/MMBtu on 24-hour basis. This limit is higher than 0.010 lbs/MMBtu (30 day rolling average), which is proposed by Warren County Biomass Energy Facility. EPD's review also shows that GREC voluntarily decided to accept this SO_2 limit and this limit did not come from a BACT review for SO_2 emissions. Based on EPD's review, 0.010 lbs/MMBtu is the correct BACT SO_2 emissions limit for a bubbling fluidized bed (BFB) Biomass Boiler.

Finally, EPD is not aware of any continuous emissions monitoring system (CEMS) for HCl that is available commercially for wood/biomass boilers. This facility is a minor source of HAPS and EPD believes that annual testing of HCl emissions and continuous sorbent injection flow rate monitoring are sufficient. Please refer to EPD's Response to Comment 6.

Comment 4:

The preliminary determination references Table C-1 in Appendix C of the application for details regarding calculations of emissions estimates that were used to determine PSD applicability for each pollutant. Table C-1 Sulfuric Acid Mist (SAM) during biomass fuel burning as 6.9 tons per year (tpy), however does not quantify expected emissions of SAM during periods of start up or shutdown which are limited in duration by the draft permit. The preliminary determination does not explain the methodology used to calculate these expected emissions nor the monitoring proposed to show actual emissions will be below the significant level of seven tons annually. The State should provide a detailed explanation of the basis for these emission estimates. EPA recommends an emission limitation be added to the draft permit to ensure PSD review applicability for SAM is not triggered and the method of demonstrating compliance with this limit be explained in detail in the final determination.

EPD Response:

The Division agrees. Condition 2.33 will be added to limit sulfuric acid mist (SAM) emissions from the bubbling fluidized bed boiler to 6.9 tons per year (tpy). Condition 6.10 will be added to require the facility to conduct performance test to determine emission factor for SAM. Conditions 7.23 and 7.24 will be added to require monthly and twelve-month recordkeeping for SAM emissions. In addition, Condition 6.2 will be modified to add the test method for sulfuric acid mist emissions.

Comment 5:

The draft permit limits the number of periods of start-up and shutdown to 40 per year total. Also, the maximum duration of start-up and shutdown periods are limited to 18 and 4 hours respectively. Given similar units have been permitted for shorter maximum duration, the State should provide the rational for allowing the extended duration of these operational periods during which compliance with BACT emission limitations is not required. The State should explain any specific details that necessitate longer start-up and shutdown durations at the proposed facility.

EPD Response:

The facility has indicated in the permit application (Volume I, Pages 3-1 to 3-3) that the timeframes for startup and shutdown for the proposed boiler are 12 hours and 4 hours respectively. The Division will modify Condition 2.6 to change the startup time from 18 hours to 12 hours.

Comment 6:

In section 4.4 of the application, the source request an avoidance emission limit for Hydrogen Chloride (HCl) to remain below the major threshold of 10 tpy of any individual HAP and 25 tpy of any combination of HAP from a stationary source. The application proposes quarterly stack testing to show emissions are below 8 tpy HCl., before changing to an annual stack test there-after to show emissions remained below 8 tpy. However, the draft permit requires only annual stack testing to determine compliance. The final determination should address the basis for this testing frequency, and should also discuss the option of continuous monitoring, much like the proposed method for determining compliance with CO, SO2, and NOx, BACT limitations that have been proposed.

EPD Response:

In addition to annual testing for HCl emissions, the permit also requires the facility to continuously monitor the sorbent injection flow rate for each sorbent used into the Duct Sorbent Injection System and report any excursions. At the time of the initial performance test for HCl, the facility will be required to establish the minimum flow rate for sorbent injection to determine compliance with the limit. Annual testing of HCl emissions and continuous sorbent injection flow rate monitoring are sufficient to comply with the permit limit. In addition, EPD is not aware of any continuous emissions monitoring system (CEMS) for HCl that is available commercially for wood/biomass boilers.

Comment 7:

The application has used AP-42 emission factors in estimates of the facility-wide emissions for PSD applicability determination purposes. Please note that because AP-42 factors are industry averages and are not intended for site specific use, the applicant does so at their own risk.

EPD Response:

Comment so noted.

Comment 8:

Beginning January 2, 2011, Green House Gasses (GHG) emissions will be covered by the PSD Program for the first time. Since this project is presently going through PSD permitting and a final PSD permit could possibly not be issued before January 2, 2011, please note GHG emissions will need to be evaluated for PSD applicability should the final permit not be issued before January 2, 2011 and detailed estimates of the GHG emissions from this PSD permitting action would need to be provided. For further information on calculating the GHG emissions associated with this PSD permitting action, please see the recently issued PSD and Title V Permitting Guidance for GHG and other information on EPA's website at www.epa.gov/nsr/ghgpermitting.html.

EPD Response:

Comment so noted.

Oglethorpe Power Corporation (OPC) COMMENTS

Comments were received from Doug Fulle, Vice President Environmental Affairs of Oglethorpe Power Corporation, by email on November 11, 2010.

Comment 1: General comments and clarifications

Oglethorpe requests that Georgia EPD make several changes to the permit ensure consistency in emission unit source codes and descriptions. Several grammatical and/or reference corrections are also requested.

a. The Bottom Ash Storage Area (Source Code BASA), which is equipped with a baghouse (Control Device ID No. BM08) is referred to as a silo and being equipped with a bin vent filter in a few locations in the permit. Specifically, please change "silo" to "area" in the cover page description and in Condition 6.2.o. The Source Code should be updated from "BASS" to "BASA" in Condition 6.2.o.

b. The Material Storage Silos (Group ID MSS) group includes various silos and the Bottom Ash Storage Area. Please refer to this collective group as "Material Storage Silos/Area" in the Emission Unit Table and in Conditions 2.16, 2.22, and 5.9.

c. Please revise the Boiler Bed Sand Storage Silo Source Code from "BBSSS" to "BBSS" since Georgia EPD's Title V operating permit application software only allows for Source Codes of up to 4 characters. References should be revised in the Emission Unit Table and in Conditions 2.15, 4.4.i, 6.2.o, and 6.8.

d. Oglethorpe requests that the emergency engines be named "Fire Water Pump Emergency Engines", not "Water Fire Pump Emergency Engines," consistent with the Emission Unit Table. References should be revised in the storage tank TK02 and TK06 descriptions in the Emission Unit Table and in Conditions 2.23, 2.24, 2.25, 2.26, 5.7, 7.20.h, and 7.21.b.x.

e. In the Emission Unit Table, Oglethorpe requests that the description for the Longwood Mobile Chipper (Source Code GRN3) be amended to note that the emission unit itself excludes the nonroad diesel engine (i.e., the regulated unit is the chipping only). The engine itself is not regulated as a stationary source; refer to additional discussion of the nonroad nature of the engine in the comment for Condition 2.26.

f. Grammatical or reference corrections should be made in the following conditions:
   - Condition 2.1 – "than" should be "that" in second sentence.
   - Condition 4.4.e – the reference of MB10 should be BM10 for the Control Device ID No.
   - Condition 5.2.g – "area" should be "are" in the second sentence.
   - Condition 5.8 – add a period to the end of the last sentence.
   - Condition 7.10.a – "were" should be "was" in the second sentence.
   - Condition 7.10.b – change "startup" to "times of startup" for clarity on what data are to be recorded.
   - Condition 7.20.i – add "(i.e., biomass or biodiesel)" after the word "type" to clarify that the intent is not to record the various individual biomass fuel types but only to distinguish between biomass and biodiesel.
   - Condition 7.21.a.i – the reference of Condition 7.14 should be Condition 7.13.

EPD Response:

The Division agrees. The bottom ash storage silo will be changed to bottom ash storage area, the material storage silos will be changed to material storage silos/area, boiler bed sand storage silo source code will be changed to BBSS, emergency engines will be renamed to Fire Water Pump Emergency Engines, description for the long wood mobile capper will be amended to note that the regulated unit is the chipping only, and grammatical or reference corrections have been changed respectively.

Comment 2: Condition 2.11 – citation correction

New Source Performance Standard (NSPS) Subpart Db does not regulate total PM_{10} or total $PM_{2.5}$ but instead only regulates PM. Oglethorpe requests that the citation for NSPS Subpart Db filterable PM limit, 40 CFR 60.43b(h)(1), be removed from Condition 2.11.

EPD Response:

The Division agrees. The citation for NSPS Subpart Db [40 CFR 60.43b(h)(1)] will be removed from Condition 2.11, because NSPS Subpart Db only regulates filterable particulate matter (PM).

Comment 3: Conditions 2.14 and 2.15 – clarification of filterable $PM_{2.5}$

Oglethorpe requests that Georgia EPD clarify that the limit applies only to filterable $PM_{2.5}$ and explicitly includes "filterable $PM_{2.5}$" rather than just "$PM_{2.5}$" in Conditions 2.14 and 2.15 to remove any ambiguity since "filterable PM_{10}" is noted in these conditions. It appears the intent of the condition is to apply only to filterable $PM_{2.5}$ but that is not definitive from the wording.

EPD Response:

The Division disagrees. This limit was intended for total $PM_{2.5}$ and not for filterable $PM_{2.5}$. Conditions 2.14 and 2.15 will be updated.

Comment 4: Condition 2.16 – NSPS Subpart OOO citation

For Condition 2.16, Oglethorpe requests that Georgia EPD add "Source Code: SSS only" after the 40 CFR 60.672 citation since NSPS Subpart OOO only applies to this unit and not to any others in Emissions Group BFPH or Emissions Group MSS.

EPD Response:

The Division agrees. Condition 2.16 will be revised to indicate that the sorbent storage silo unit is the only unit subject to NSPS Subpart OOO.

Comment 5: Condition 2.21 – 40 CFR 63 classification

The Warren facility is an area source with respect to 40 CFR 63; it is not avoiding 40 CFR 63 and will be subject to the forthcoming standard for industrial boilers at area sources. Oglethorpe requests that the citation for Condition 2.21 be revised to "40 CFR 63 Area Source Classification".

EPD Response:

The Division agrees. Condition 2.21 will be revised to indicate that the facility is an area source with respect to 40 CFR 63 and will be subject to the forthcoming standard for industrial boilers at area sources.

Comment 6: Condition 2.22 – PWR applicability clarification

The Process Weight Rule (PWR) applies to each individual system and storage silo/area, not the entire collection of systems and silos/areas. Therefore, Condition 2.22 needs to be revised to refer to "each" rather than "all". Please see the proposed revisions included in Attachment 1 for this condition.

EPD Response:

The Division agrees. Condition 2.22 will be revised to indicate this change.

Comment 7: Condition 2.24 – Certified engine purchase requirement

Condition 2.24 includes opacity restrictions that are applicable to manufacturers of engines, not owners or operators. NSPS Subpart IIII requires owners and operators to purchase certified engines. Oglethorpe requests that Georgia EPD revise this condition to require purchase of engines certified to meet the opacity limits and revise the corresponding citation.

EPD Response:

The Division agrees. Condition 2.24 will be revised to require the facility to install fire water pumps according to manufacturer's specifications per NSPS Subpart IIII. However, the correct citation is updated as 40 CFR 60.4211(c).

Comment 8: Conditions 2.26 and 7.21.b.x – Exclusion of nonroad engine

The Longwood Mobile Chipper's engine is considered a non-road engine per the regulatory definition of 40 CFR 89.2 and 40 CFR 1068.30 as discussed in Section 4.1 of Volume I of the permit application. As summarized in the narrative, a nonroad engine must be portable or transportable, not remain in a location for more than 12 consecutive months, and not be regulated under an NSPS. The chipper engine will be portable, will have conditions restricting on-site presence to less than 12 consecutive months, and is not subject to an NSPS; therefore, it is a nonroad engine. Nonroad engines are specifically exempted from the stationary source definition under the Clean Air Act (CAA). Therefore, the engine itself is exempt from construction permitting under the PSD Program (and also exempt from the Title V operating permit program).

The chipper engine is not subject to the fuel sulfur limits of Condition 2.26 since it is not a stationary source and is not regulated under PSD, NSPS Subpart IIII, or Georgia Rules for Air Quality Control (GRAQC) 391-3-1-.02(2)(g). Oglethorpe requests the reference to the chipper (which we previously requested be further defined in the Emission Unit Table to specifically exclude the nonroad engine) be removed from Condition 2.26 and the subsequent exceedances reporting condition, Condition 7.21.b.x.

EPD Response:

The Division agrees. Conditions 2.26 and 7.21.b.x will be revised to remove the Longwood Mobile Chipper, because it is considered a non-road mobile engine and it is not regulated under PSD, NSPS Subpart IIII, or Georgia Rules for Air Quality Control (GRAQC) 391-3-1-.02(2)(g).

Comment 9: Conditions 2.26 and 7.22 – Allowance for usage of the chipper throughout life of the permit

To maintain the nonroad definition of 40 CFR 89.2 and 40 CFR 1068.30, the Longwood Mobile Chipper cannot remain "at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source." A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. Georgia EPD has previously received guidance on this topic from EPA in discussing the Lockheed Martin operations in Marietta.[1]

> *As stated in our December 1, 1995, letter, the definition of stationary source in section 302 of the Clean Air Act (CAA) does not include nonroad engines or nonroad vehicles, as defined in section 216. According to the definition of nonroad engine in 40 CFR Part 89.2, internal combustion engines are not considered to be nonroad engines if they remain or will remain at a location for more than 12 consecutive months ~ or a shorter period of time for an engine located at a seasonal source. Your letter is correct in that 40 CFR Part 89.2 specifically defines a location as any single site at a building, structure, facility, or installation. As such, a specific piece of aerospace ground equipment would be considered a stationary source unless it is determined that it is moved (for reasons other than to solely qualify it as mobile) to another location within the requisite time period.*

Oglethorpe understands that a single engine cannot remain in place for 12 consecutive months. However, once that engine is removed and time passes, Oglethorpe would be allowed to bring another identical (or smaller) unit on-site for usage, provided that new unit also does not remain in place for 12 consecutive months while still meeting the nonroad classification. For example, Oglethorpe may bring the chipper on-site for usage in the fall and winter, remove it for the spring and summer, and bring on-site a new unit for the following fall and winter. Such usage would maintain the nonroad classification of the engine and would allow usage of the chipper, on an intermittent basis, throughout the life of the permit.

Conditions 2.27 and 7.22 of the draft permit, however, could be read to restrict usage of the chipper to a one-time usage of not more than 12 consecutive months and only immediately after startup of the boiler. Oglethorpe requests that that Condition 2.27 be revised to restrict the chipper engine to being on-site no more than 12 consecutive months at a time (and not be tied to the startup of the boiler). Oglethorpe also requests that Condition 7.22 be revised to include notifications within 30 days of each instance of bringing the chipper on-site or removing it from the site.

EPD Response:

The Division agrees. Condition 2.27 will be revised to clarify that the 12 consecutive months restriction only applies to the chipper engine and it is not be tied to the startup of the boiler. In addition, Condition 7.22 will be revised to include notifications within 30 days of each instance of bringing the chipper on-site or removing it from the site.

[1] Letter from Mr. Brian Beals (EPA Region 4) to Mr. Edward A. "Tony" Cutrer, Jr. (Georgia EPD), March 12, 1996.

Comment 10: Conditions 2.29 and 2.30 – 1-hour emissions limits

In the proposed draft permit, Georgia EPD included two permit conditions related to meeting new National Ambient Air Quality Standards (NAAQS). New NAAQS have been established for NO_2 and SO_2 on a 1-hr basis, and supplemental modeling to demonstrate compliance with these NAAQS was submitted on June 25, 2010 (NO_2) and July 27, 2010 (SO_2). In both of the modeling submittals, Oglethorpe requested that if Georgia EPD deemed them necessary that permit limits for 1-hr NAAQS compliance be issued in a lb/hr form consistent with the basis for the limits being modeling, rather than Best Available Control Technology (BACT) format of lb/MMBtu. These 1-hr NAAQS submittals were consistent with Section 4.1.2 of Volume II of the permit application, which noted, "Oglethorpe has modeled short term emission rates that are higher than the BACT limits".

Oglethorpe has three comments on the proposed limits.

a. Proposed limits are inappropriately identified as BACT limits.
b. Proposed limits are in a lb/MMBtu form rather than the more relevant lb/hr form for modeling limits.
c. The calculated lb/MMBtu values appear to be based on a misunderstanding by Georgia EPD of the derivation of the values that were modeled.

A. Limits Inappropriately Identified as BACT

Permit limits issued under PSD can derive from a myriad of sources, all of which can be linked to Clean Air Act §165(a), which sets requirements a source triggering PSD must satisfy to commence construction.

1. Possess a PSD permit.
2. Hold a public comment period on the draft permit
3. Meet ambient concentration levels (NAAQS/Increment) and NSPS/NESHAP
4. Apply BACT
5. Address Class I area impacts
6. Address growth impacts
7. Have suitable air monitoring data

Thus, looking broadly, PSD emission limits could be set based on modeling, BACT, Class I area impacts, or growth impacts. A limit set under any of these areas would be a PSD limit, but only limits set based on BACT would be BACT limits.

The requirements of BACT are discussed in Section 5.1 of Volume I of the permit application. There is no reference in the definition of BACT to NAAQS because the BACT determination and the NAAQS analysis are distinct requirements with distinct analyses.

While the 1-hr NO_2 and 1-hr SO_2 NAAQS may appear to present a new issue, in reality the question here is no different than it has already been for the 3-hr SO_2 NAAQS, which historically was an issue for coal-fired power plants. Many permits have been issued for coal-fired power plants with 3-hr SO_2 emission rate (lb/hr) limits based on modeling rather than BACT. In the recent Power 4 Georgian's permit, Georgia EPD did issue a 3-hour SO_2 limit as BACT (lb/hr form), but also instead issued the 24-hour SO_2 limit as a modeling-only, non-BACT limit. The 24-hour SO_2 limit in that case was developed to avoid Class I area impacts, just as the 1-hr SO_2 and 1-hr NO_2 limits for Warren were developed only to insure NAAQS compliance.

Lastly, for a limit to be classified as a BACT limit, it must have been evaluated via the BACT process, which is not the case here. Neither Georgia EPD nor Oglethorpe performed a BACT analysis for the 1-hour average emission limits. The only driver for the limits was the new NAAQS standards and modeling.

B. Form of Limit

Georgia EPD proposed the form of the short-term limit on a lb/MMBtu basis rather than the requested lb/hr basis without articulating a reason. For units like the proposed Warren facility boiler where there is a flow monitor to continuously convert concentration readings to mass readings, lb/hr is the appropriate form for modeling-based limits.

Under typical boiler operation at high load levels, there is little difference in the lb/hr and lb/MMBtu forms. However, Oglethorpe will have a CEMS calculating compliance for every hour of the year, and not every hour of operation will be at a high load level. At low load levels and particularly during startup, while the mass emission rate may be well below the lb/hr limit, the lb/MMBtu value can be much higher due to the low heat input. As a result, the lb/MMBtu form is not reasonably keyed to NAAQS compliance.

C. Incorrect Values

As explained above, we recommend that the NAAQS compliance limits for the 1-hour SO_2 and NO_2 standards should be expressed in a lb/hr form. We note however, that the values listed in the draft permit are 0.28 lb/MMBtu NOx and 0.095 lb/MMBtu SO_2, while the basis for the values should instead be 0.30 lb/MMBtu NOx and 0.010 lb/MMBtu SO_2. It appears that there may have been a misunderstanding regarding the modeling inputs due to the worst-case operating load being 1,329 MMBtu/hr (Scenario 1) rather than 1,399 MMBtu/hr (Scenario 8).

As documented in the updated load modeling analysis submitted to Georgia EPD on March 5, 2010, Scenario 1 (1,329 MMBtu/hr) resulted in the highest modeled impacts for SO_2; in contrast the highest heat input case (Scenario 8 – 1,399 MMBtu/hr) resulted in the 6th highest impact. Thus, Oglethorpe used Scenario 1 for the refined 1-hr SO_2 modeling since Scenario 1 results in the highest impact of any of the scenarios.

For NOx, Scenario 7 (566 MMBtu/hr) resulted in slightly higher impacts than Scenario 1, but only because Scenario 7 assumed a higher NOx rate than in the remaining seven cases. Since Scenario 1 resulted in the highest impact per mass of emissions for NOx, Oglethorpe used Scenario 1 for the refined 1-hr NO_2 modeling.

Thus, for both 1-hr SO_2 and 1-hr NO_2, the scenario with the highest modeled impacts per mass of emissions is Scenario 1 (1,329 MMBtu/hr). Had Oglethorpe instead used Scenario 8 (1,399 MMBtu/hr) in modeling, the predicted impacts would decrease compared to Scenario 1, even though the mass emission rate for Scenario 1 is lower than for Scenario 8.

Using Scenario 1 (1,329 MMBtu/hr) results in modeled emission rates of 398.7 lb/hr (NOx) and 132.9 lb/hr (SO_2), and compliance was demonstrated with these emission rates. However, the appropriate limit would instead be based on Scenario 8 (1,399 MMBtu/hr), which would have lesser impacts than Scenario 1 despite the higher emission rates. Thus, the correct mass emission rate limits are 419.7 lb/hr (NOx) and 139.9 lb/hr (SO_2).

It appears that to develop the lb/MMBtu values listed in the draft permit, Georgia EPD used the modeled Scenario 1 mass emission rate and divided it by the Scenario 8 heat input, as that approach results in the values included in the draft permit (0.28 lb/MMBtu NOx and 0.095 lb/MMBtu SO_2). Given the complexities of the various load scenarios, it is easily understandable how one could misunderstand the inputs and arrive at the values in the draft permit.

D. Proposed Revision

Oglethorpe requests that Georgia EPD revise Conditions 2.29 and 2.30 to reflect the maximum 1-hr lb/hr emission rates for the NOx (419.7 lb/hr) and SO_2 (139.9 lb/hr) NAAQS demonstrations. Additionally, the citation should be updated from the BACT citation of 40 CFR 52.21(j) to the NAAQS compliance requirement of 40 CFR 52.21(k).

EPD Response:

The Division agrees with subparagraphs a and b of the comment. The 1-hour limits for NOx and SO_2 are modeling limits to ensure the facility complies with the new 1-hour NAAQS standards.

The Division does not agree entirely with subparagraphs c and d of the comment. Based on EPD's modeling review, the worst case modeled NOx and SO_2 rates were 372.1 lbs/hr and 132.9 lbs/hr respectively. These modeled rates should comply with the 1-hour NAAQS standards. Therefore, the Division will modify the NOx limit in Condition 2.29 from 0.28 lbs/MMBtu to 372.1 lbs/hr and will modify the SO_2 limit in Condition 2.30 from 0.095 lbs/MMBtu to 132.9 lbs/hr. The facility will be required to install a continuous emissions rate monitoring systems (CERMS) for NOx and SO_2 emissions to determine compliance with the pounds per hour limits and Conditions 5.2.a and 5.2.c will be modified.

Comment 11: Condition 2.32 – NSPS Subpart OOO

Oglethorpe requests that Condition 3.32 be revised to reflect the current version of NSPS Subpart OOO. The first correction needed is the citation: 40 CFR 60.672 only includes (a) through (f) now (the version prior to the April 2009 revisions included through (h)). The introductory paragraph of Condition 2.32.c as well as items c.i and c.ii should be removed as they are from the previous version of 40 CFR 60.672(h) and were removed with the April 2009 revisions. The ending paragraph of Condition 2.32.c, starting with "For processing equipment subject to 40 CFR 60, Subpart OOO located inside a building…" should be retained as it is part of the current 40 CFR 60.672(e) requirement. Conditions 2.32.d and e should also be part of the Condition 2.32.c requirements, not stand-alone conditions (i.e., both of those apply OR Conditions 2.32.a and b requirements apply to processing equipment inside a building). Refer to the redline version of the permit in Attachment 1 for the proposed revisions.

EPD Response:

The Division agrees. Condition 2.32 will be revised to reflect the current version of NSPS Subpart OOO.

Comment 12: Conditions 4.1, 4.2, and 7.21.c.i – Control device operation

As discussed in Section 2.2.1 of Volume I of the permit application narrative, the boiler control devices cannot operate during all periods of operation of the boiler. Section 2.2.1 noted the following during the discussion of the boiler startup procedures:

> *During this phase* [Phase I],*… The SNCR cannot be operated, as the boiler temperatures are too low for ammonia injection. The fabric filter is also bypassed during this time to avoid condensation on the fabric filter bags. Because of the fabric filter bypass, and because of insufficient flue gas temperature, the duct injection system is also not in operation. …*
>
> *Phase II of startup is the transition phase where biomass feed begins and auxiliary fuel decreases. … It is estimated that approximately halfway through Phase II…, the temperature of flue gas exiting the air heater will be above the acid dew point and the fabric filter can be used. Since the duct sorbent injection system depends on the fabric filter for collection of the sorbent, the duct sorbent injection system can also be used at this point.*
>
> *Phase III is the end of the startup period…. During Phase III, only biomass is fired in the boiler, and the load is increased from approximately 50% to 65% load. The SNCR can be used for NO_X control at approximately 65% load …. At this point, the flue gas temperature inside the boiler (at the ammonia injection lances) is above the required minimum ammonia injection temperature. The baghouse and duct sorbent injection systems are utilized throughout Phase III. Note that while 65% load is required to initiate SNCR usage, once the SNCR is active its usage can be maintained down to 40% load.*

Similarly, operating constraints prohibit continued usage of the SNCR and DSI during a rapid boiler shutdown event (usage of the baghouse is expected to continue). Based on these constraints, Oglethorpe cannot operate the devices at all times the boiler is operating and requests that clarifying language such as "except during periods of startup and shutdown; device will be operated as soon as practicable after initiation of startup of B001" be added to Conditions 4.1, 4.2, and 4.3. Additionally, clarifying language should be added to Condition 7.21.c.i to indicate that periods when the control devices are not in operation or are bypassed shall not be excursions if such periods are exempted per Conditions 4.1, 4.2 and/or 4.3.

Note that Georgia EPD recognized that operation of these devices cannot occur during certain operations, noting the following in the Preliminary Determination:

> *…during these periods of operation [startup and/or shutdown], operating conditions such as temperature and flow rates of the unit exhaust from the boiler may not be conducive to proper operation of the applicable control systems (Fabric filter, SNCR, and DSI system)…*

Oglethorpe desires to have this clarification as part of the operating permit, not just the accompanying determination.

EPD Response:

The Division agrees. Conditions 4.1, 4.2, 4.3, and 7.21.c.i will be revised to clarify the control devices operation conditions, because control devices cannot operate during all periods of operation of the boiler especially during periods of startup and shutdown.

Comment 13: Condition 5.2.d – CO_2 or O_2 monitor

Oglethorpe requests that "and" be revised to "or" in the second sentence of Condition 5.2.d since NSPS Subpart Db requires that either a CO_2 **or** an O_2 monitor be installed, not both. This change will make the second sentence consistent with the first sentence of this condition.

EPD Response:

The Division agrees. Condition 5.2.d will be revised to allow the facility to monitor CO_2 or O_2 using a CEMS, per NSPS Subpart Db.

Comment 14: Condition 5.10 – Separate 60-day period for BM10

Oglethorpe intends to use the Longwood Mobile Chipper on an as-needed basis and does not intend to bring it on-site until needed. Thus, neither it nor the associated baghouse BM10 may be in place within 60 days of the initial startup of the boiler. Oglethorpe requests that Condition 5.10 be amended to reflect submittal of a Preventative Maintenance Program for baghouses BM01 through BM09 (which are integral to startup of the boiler and will be in operation when the facility starts up) within 60 days of the boiler startup and submittal of a separate plan for BM10 within 60 days of startup of the chipper.

EPD Response:

The Division agrees. Condition 5.10 will be revised to require submitting the Preventive Maintenance Program for baghouse BM10 associated with the Longwood Mobile Chipper within 60 days of the initial startup of the chipper, because the chipper will be used on the site on an as-needed basis.

Comment 15: Condition 6.2 – Usage of OTM-028

Oglethorpe requests the option to use Other Test Method 28 (OTM-028) in lieu of Method 202 when determining the condensable portion of the total PM_{10} concentrations for Conditions 6.2.j and 6.2.o, consistent with Georgia EPD's allowance of this method to measure the condensable fraction of total $PM_{2.5}$ in Condition 6.2.l. (Both Method 202 and OTM-028 measure condensable PM, all of which is less than 2.5 microns.).

EPD Response:

The Division disagrees. Method 202 is considered the reference method; US EPA intents to replace Method 202 with the procedures of OTM-028 and will still call Method 202. In the event that US EPA does not make this change in the future, the facility may request the Division to use the procedures of OTM-028 in lieu of Method 202.

Comment 16: Condition 6.2.x – Specification of ASTM Methods

Oglethorpe requests that Georgia EPD list the specific ASTM methods to be used for fuel oil sulfur content in Condition 6.2.x rather than cite Method 19, Section 12.3.2.2.3 of their *Procedures for Testing and Monitoring Sources of Air Pollutants*. Plant personnel are familiar with ASTM methods and can readily ascertain if the correct method is being used if the methods are explicitly stated in the permit. Conversely, listing only Method 19 is not intuitive and would require additional research to ascertain which methods are authorized. Listing the methods improves the usability of the permit.

EPD Response:

The Division agrees. Condition 6.2.x will be modified to add the facility requested specific ASTM methods. However, the Division will keep the Method 19, Section 12.3.2.2.3 to insure that all necessary procedures are citied.

Comment 17: Conditions 6.3, 7.5, 7.6, and 7.7 – Exclusion of startup and shutdown emissions

As discussed in the comments for Conditions 4.1, 4.2, and 4.3, the control devices cannot operate during periods of startup and shutdown. As such Oglethorpe proposed BACT limits for NO_X, CO, and SO_2 with a 30-day averaging period that excluded periods of startups and shutdowns. Georgia EPD agreed and included similar BACT limits (with the startup and shutdown exclusions) in Conditions 2.9, 2.12, and 2.13. Therefore, the data monitored by the CEMS and used for the 30-day averaging period calculations should only include valid data and exclude data measured during periods of startup and shutdown. Oglethorpe requests that Condition 6.3 be revised to include "valid" before the word "hourly" in the last sentence of each subcondition and the phrase "and shall exclude periods of startup and shutdown" be added to the end of the last sentence in each subcondition.

Similarly, Oglethorpe requests the sentence "The average shall exclude data from periods of startup and shutdown." be added to Conditions 7.5.b, 7.6.b, and 7.7.a.

EPD Response:

The Division agrees. Conditions 7.5, 7.6, and 7.7 have been updated. Please refer to the Division's response to Comment 12.

Comment 18: Condition 6.4 – Performance testing time frame

NSPS Subpart Db allows for completion of performance testing within 60 days of achieving maximum production but no later than 180 days after startup. This time frame is noted in the first sentence of this condition. However, the second sentence contradicts this by stating "…done initially within the **earliest** timeframe specified…" (emphasis added). Oglethorpe requests that the word "earliest" be removed, making the time frame consistent with the NSPS Subpart Db requirement and allowing up to 180 days after startup to complete the testing.

EPD Response:

The Division agrees. Condition 6.4 will be modified to delete the word earliest in the second sentence, in order to be consistent with the NSPS Subpart Db requirements.

Comment 19: Condition 6.5 – Clarification of HCl data usage

Condition 6.5 implies that the HCl test data shall be used to assess compliance with an HCl emission limit. However, no specific HCl emission limit is included in the permit. Rather, the HCl data shall be used, per Conditions 7.16.a and c, as part of the compliance assessment for the maximum single HAP limit of 10 tpy and total HAP limit of 25 tpy. Oglethorpe requests that Condition 6.5 be worded to reference usage of the test-derived emission factor to calculate HCl emissions are required by Condition 7.16.a. Refer to the proposed revisions included in the redline permit included in Attachment 1.

EPD Response:

The Division agrees. Condition 6.5 will be modified to reflect the correct reference condition for HCl data used to derive emission factor to calculate HCl emissions.

Comment 20: Condition 6.6 – Acrolein, Benzene, and Formaldehyde testing

Oglethorpe requests removal of the requirement to perform initial stack testing for acrolein, benzene, and formaldehyde testing for the boiler. Emissions of these pollutants are expected to be quite small (relative to the AP-42 factors) due to the bubbling fluidized bed design of the boiler. Further, given the VOC emission rate based on vendor data, Oglethorpe is confident emissions of these HAP are less than the major source thresholds for single HAP and will maintain overall facility HAP of less than 25 tpy.

Section 3.2.1 of the Volume I permit application narrative noted Oglethorpe's HAP factor development process as follows:

> *Given the age of the AP-42 biomass combustion factors and the heavy influence of stoker boiler data in the AP-42 factors[2], custom HAP and TAP emission factors were developed based on fluidized bed boiler emission data available in the AP-42 Section 1.6 background database[3] and/or the U.S. EPA original Boiler MACT database.[4] If fluidized bed boiler emission data were not available for an organic HAP or TAP listed in AP-42 Section 1.6, default AP-42 Section 1.6 factors were used instead.*

Acrolein

The acrolein fluidized bed combustor (FBC) boiler factor was based on 6 test data (see the table in Attachment 2), and while not as many data as the AP-42 factor, six points is still adequate to develop a reasonable value consistent with the quality of other HAP factors in AP-42 Section 1.6. A review of the tested data used for the AP-42 factor includes a wide variety of emission rates, from 1.27E-04 to 4.05E-07 lb/MMBtu for stoker boilers, illustrating the wide range in data. Maine DEP has indicated that they believe the AP-42 factor is inaccurate as it includes test data that should be deemed outliers, and test results from wood residue-fired boilers in that state have yielded emissions much less than the AP-42 factor of 4.00E-03 lb/MMBtu (refer to the discussion of Maine DEP acrolein data included in Appendix C of the Volume I permit application). The FBC boiler test data included five sets of test data that were below detection limits and one set that was detected, with a range of 3.60E-05 to 8.38E-07 lb/MMBtu. Therefore, Oglethorpe believes the custom factor, 9.78E-06 lb/MMBtu, is appropriate for the proposed boiler.

Benzene

An examination of the AP-42 factor data shows that it includes data from two stoker boilers with emissions of greater than 0.1 lb/MMBtu while some other stoker boiler factors are less than 3E-07 lb/MMBtu (an overall AP-42 factor of 4.20E-03 lb/MMBtu is listed in AP-42 Section 1.6). The benzene FBC boiler factor is based on 8 test data sets (refer to the table in Attachment 2) with a narrow range of 3.92E-05 to 2.46E-06 lb/MMBtu. Therefore, Oglethorpe believes the custom factor, 1.39E-05 lb/MMBtu, is appropriate for the proposed boiler.

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

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

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

Formaldehyde

The formaldehyde FBC boiler factor is based on a smaller number of test data than the AP-42 factor. However, the FBC boiler data ranges from 7.80E-04 to 1.10E-05 lb/MMBtu, a much tighter range than the AP-42 factor data, 2.94E-01 to 9.60E-06 lb/MMBtu. As the formaldehyde custom FBC boiler factor of 1.78E-04 lb/MMBtu is based on 6 data sets (see the table in Attachment 2), Oglethorpe believes it is still more representative for FBC boilers than the AP-42 factor of 4.40E-03 lb/MMBtu.

Based on this research, Oglethorpe is confident that emissions of acrolein, benzene, and formaldehyde are lower than represented by default AP-42 factors and does not believe there is a need to conduct stacks testing on the new, state-of-the-art, bubbling fluidized bed boiler.

EPD Response:

The Division disagrees. These performance tests are required by the Division to determine accurate Acrolein, Benzene, and Formaldehyde emission factors (in lbs/MMBtu) for a bubbling fluidized bed boiler, which will be used to calculate single HAP and combined HAPS emissions to insure compliance with Condition 2.21.

Comment 21: Condition 6.9 – Repeat testing

Condition 6.9 includes the initial opacity performance testing requirement of NSPS Subpart OOO for the Sorbent Storage Silo. It also lists a requirement to perform additional testing every 5 years. The silo is equipped with a bin vent filter control device, and under NSPS Subpart OOO, the silo is subject to the requirements listed in Table 2 (devices with capture systems). Table 2 specifies that an initial performance test is required; it does not require subsequent compliance tests. Repeat tests are only required every 5 years, per Table 3, for units without control devices or for fugitive emissions. Oglethorpe requests that the requirement to repeat the testing every 5 years be removed to ensure consistency with the NSPS Subpart OOO requirements. Additionally, the citation should be corrected to 60.672(f), not 60.675(f) since the former is the requirement to meet the Table 2 requirements while the latter prescribes usage of monitoring devices during PM stack testing.

EPD Response:

The Division agrees. Condition 6.9 will be revised to reflect the current version of NSPS Subpart OOO.

Comment 22: Condition 7.16 – Actual heat input

Oglethorpe requests that Georgia EPD revise the Condition 7.16 equations to utilize actual monthly heat input capacity, as measured by the data acquisition and handling system (DAHS), rather than usage of the monthly hours of operation and rated heat input capacity. Usage of the monthly actual heat input will yield an accurate estimate of actual emissions whereas usage of the monthly hours of operation and rated heat input will yield an overestimate of actual emissions since the boiler will not operate at its maximum rated capacity for every hour of operation.

As previously noted by Oglethorpe, the maximum rated capacity of 1,399 MMBtu/hr is not sustainable; the maximum sustainable heat input is 1,282 MMBtu/hr. Should Georgia EPD disagree with using the MMBtu/month as measured by the DAHS, the rated capacity to be used in the calculations should be the sustainable capacity of 1,282 MMBtu/hr. Oglethorpe asserts that usage of the measured MMBtu should be used however.

EPD Response:

The Division agrees. Condition 7.16 will be revised to utilize actual monthly heat input capacity, as measured by the data acquisition and handling system (DAHS), rather than usage of the monthly hours of operation and rated heat input capacity.

Comment 23: Condition 7.21.b – Reference section 2 conditions

Oglethorpe requests that Georgia EPD revises the Condition 7.21.b provisions to simply reference the limits established by the Section 2 conditions rather than repeat the numeric limits here. Several revisions are requested for the Section 2 conditions (i.e., format and magnitudes of 1-hr modeling-based limits, exclusions for startup/shutdown emissions) that would also need to be made in this section if a cross-reference is not used. Usage of the cross-referencing would ensure consistency between the actual limits and the data being assessed for compliance (i.e., when startup or shutdown data are excluded) and clearly indicates the basis of the exceedances reporting requirements.

EPD Response:

The Division agrees. Condition 7.21.b will be modified to reference the limits established by Section 2 Conditions, rather than repeating the numeric limits of Section 2 Conditions.

Comment 24: Preliminary determination corrections

Oglethorpe requests that Georgia EPD correct the following inaccurate statements included in the issued Preliminary Determination. Additionally, revisions related to the requested permit condition revisions previously discussed in this letter should be addressed in the Final Determination.

a. In Table 1-1, the potential emissions of PM are 143.8 tpy and are not equal to the PM_{10} emissions. PM emissions represent just filterable PM, while PM_{10} emissions included in this table are the summation of filterable PM_{10} and condensable PM.

b. In the Section 2.0 Process Description, please clarify that the boiler maximum heat input of 1,399 MMBtu/hr is a daily maximum as represented in the application. The sustainable annual rate for the boiler, however, is 1,282 MMBtu/hr.

c. In the SO_2 BACT section for the boiler, the determination references SO_2 1-hour Class II modeling submitted on June 25, 2010. The actual SO_2 submittal was on July 27, 2010, as noted in Appendix B of the Preliminary Determination.

d. The Material Storage Silos/Areas BACT summary indicates the Bottom Ash Storage is a silo equipped with a bin vent filter. The source is actually a storage area and is equipped with a baghouse (the draft permit lists these units correctly).

e. Section 5.0 notes that BACT requirements for the boiler subsume the NSPS Subpart Db requirements for NO_X and SO_2. However, as noted previously in the determination, the boiler is not subject to NSPS Subpart Db NOx or SO_2 requirements. Similarly, GRAQC 391-3-1-.02(2)(d) NOx limits do not apply since the boiler does not have the capacity to combust 250 MMBtu/hr or greater of fossil fuel.

f. The text below Table 6-2 indicates, "The NAAQS analysis would include…all emission units… except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations." As part of the 1-hour NO_2 and SO_2 NAAQS analysis, Oglethorpe included emissions from the proposed emergency engines.

g. In the PSD Increment Analysis text just above Table 6-3, Georgia EPD indicates $PM_{2.5}$ increments are expected to be added soon. The $PM_{2.5}$ Increments were signed on September 29, 2010; however, they do not apply to the proposed project, as they do not become effective until one year from the rule publication in the Federal Register; the rule was just published on October 20, 2010.

h. The UTM North coordinates listed in Tables 6-4 through 6-7 are missing a digit.

i. Oglethorpe is unable to verify the modeled impacts listed in Tables 6-4 through 6-7, as these do not match the submitted modeling analyses, although they are generally similar and reach the same conclusions.

j. In the NAAQS and Increment Modeling section, Georgia EPD references grouping sources within 5 km together for the 20D analysis. Oglethorpe is uncertain whether Georgia EPD did the grouping based on 5 km; however, the submitted analyses grouped sources within 2 km in accordance with the approved modeling protocol and U.S. EPA guidance.

k. The Additional Impacts Visibility section states there were no potentially sensitive receptors within 24.5 km of the facility. However, subsequent review found that the Thomson-McDuffie airport is within the 1-hour NO_2 significant impact radius. Oglethorpe performed a Level II VISCREEN analysis for this airport and determined that no adverse impacts are predicted. Refer to the analysis included in Attachment 3.

l. Oglethorpe noted that the Appendix D BACT comparison table included a coal-fired boiler, Louisiana Generating, LLC Big Cajun II Power Plant. This unit should be removed from the Appendix D table. Additionally, a number of the units are listed twice in the workbook and/or only have determinations listed for pollutants for which the Warren facility did not require PSD permitting and thus, did not require BACT limits (i.e., H_2SO_4, VOC).

EPD Response:

The Division agrees with paragraph a of this comment. Table 1-1 of preliminary determination will be revised as follow:

Table 1-1: Emissions from the Project

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	143.8*	25	Yes
PM_{10}	144.4	15	Yes
$PM_{2.5}$	134.6	10	Yes
VOC	39.1	40	No
NO_X	648.9	40	Yes
CO	625.7	100	Yes

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
SO_2	56.2	40	Yes
H_2SO_4	6.90	7	No
Fluorides	0	3	No
PB	8.13E-04	0.6	No
Total HAP	19.9	25	No
Max. Single HAP	9.9	10	No

* PM emissions represent just filterable PM, while PM_{10} emissions included filterable PM_{10} and condensable PM.

The Division agrees with paragraphs b of the comment. Emission Unit Table in permit is updated for B001 to include the reference to annual sustainable heat input capacity of 1,282 MMBtu/hr.

The Division agrees with paragraphs c through h and paragraph l of the comment.

In response to paragraph i of the comment, the differences between the Division modeling and the facility submitted modeling analysis are as follow: In Class II significance analysis, the worst case scenarios were correctly chosen based on EPD's analysis using AERMOD instead of SCREEN3 used by the applicant; The offsite inventory for PM10 has been updated and corrected; the calculation for the modeled concentrations in comparison with NAAQS for 1-hour NO_2, SO_2, and 24-hour and annual $PM_{2.5}$ followed the EPA guidance, while the applicant used supposedly more conservative methods.

The Division agrees with paragraph j of the comment. The sources should be grouped within 2 km together for the 20D analysis in the NAAQS and Increment modeling.

In response to paragraph k of the comment, EPD's modeling staff approved the Level I and II VISCREEN analysis for the Thomson–McDuffie airport located within 24.5 km of the facility. No adverse impacts are predicted.

Citizens COMMENTS

Please refer to Appendix B of this document to view the entire copy of the public comments received. Please note only comments related to air quality will be addressed. Many of the comments submitted by citizens are as follows:

Comments were received from James H Newsome, by email on November 19, 2010.

Comment 1:

Mercury Emissions

It is my understanding that the EPD documents and draft air permit do not address the level of mercury emissions from the proposed facility. The answer I received during the question and answer part of the meeting from Mr. Douglas Fulle of Oglethorpe Power was that the mercury emission would be so low that it was not included in the draft air permit.

As I stated last night, we know that the mercury level in nearby waterways, such as the Ogeechee River, already exceed the Total Maximum Daily Load (TMDL). Therefore, any new emission of mercury is a concern regardless of the level.

I respectfully request that the annual level of mercury to be released from the proposed facility be addressed in the air permit and that mercury emission monitoring be required by EPD in the final permit.

EPD Response:

This facility is an area source for hazardous air pollutants (i.e. potential emissions of any single hazardous air pollutant is less than 10 tpy and emissions of all combined hazardous air pollutants (HAPs) is less than 25 tpy). 40 CFR 63 Subpart B, Section 112(g) requirements do not apply to this facility because the facility is an area (or minor) source of HAPs. The permit application for Warren County Biomass Energy Facility addresses mercury emissions in Volume I, Appendix C, Table C-2. Mercury emissions from this proposed biomass-fired boiler are approximately 11.2 pounds per year. No mercury emissions monitoring is required per any Air Quality regulations.

The facility conducted a Toxics Impact Assessment and EPD independently verified the results. Please refer to the Permit Application, Volume II, Appendix F, Table F-2 for Toxics Modeling analysis. This analysis shows that mercury impacts from the biomass boiler are approximately 0.01% of the allowable acceptable ambient concentrations (AAC) for mercury.

Also, this permit only addresses air quality concerns and addressing mercury emissions in the waterways are beyond the scope of this project.

Comment 2:

Particulate Matter

I was pleased to learn that Oglethorpe Power is planning to include state of the art air pollution controls in the facility. It is my understanding that the annual emissions will still contain over 170 tons of particulate matter.

While this level of emission may be low compared to the other facilities, it is "high) if you live nearby. Although my home is located about three miles from the facility site, and generally upwind, I am still concerned about any increase of particulate matter in my community.

There are many know health related issues that result from exposure to particulates in the air. Does the permit require Oglethorpe Power to monitor the overall emission of particulates and inform the public of those levels on a regular basis? If the level of exceeds the estimated (and I assume permitted) level will EPD require the facility to comply or suspend operations?

EPD Response:

In order to comply with the PM_{10} emissions limit on the boiler stack, the facility is required to conduct performance test for PM_{10} emissions. The facility is also required to install a continuous opacity monitoring system (COMS) on the boiler stack to continuously measure opacity or visible emissions being emitted from the stack. Monitoring opacity is an appropriate surrogate monitoring for particulate matter emissions to demonstrate compliance with the PSD limits.

If the facility exceeds the PM_{10} emissions limit or any other limit in the permit, the facility will be subject to enforcement action by Georgia EPD and it could result in suspension of operations at the facility.

Comments were received from Katherine Helms Cummings, by email on November 19, 2010.

Comment 3:

Building new biomass facilities…how wastewater discharges will be handled.

EPD Response:

The Georgia Rules for Air Quality Control and the Federal Rules for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) are designed to protect the environment and human health. An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed modification. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, $PM_{2.5}$, SO_2, Ozone (O_3), and lead (Pb). PSD increments exist for SO_2, NO_2, $PM_{2.5}$, and PM_{10}.

It has been determined through approved modeling techniques that the estimated emissions for Warren County Biomass Energy Facility will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants being emitted, such as HAPs (which includes mercury). Impacts from each of the pollutants were analyzed using the EPD Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version June 21, 1998). The Georgia Air Toxics Guideline is a guide for estimating the environmental impact of sources of toxic air pollutants. A toxic air pollutant is defined as any substance, which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard.

The Georgia Air Quality Act and the Georgia Rules in 391-3-1-.03(1)(c) state that the permit for the construction or modification of any facility shall be issued upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Therefore, Georgia EPD must issue an air quality permit for the Warren County Biomass Energy Facility if they meet all applicable requirements in the rules and regulations that are applicable.

Also, please refer to EPD's Response to Citizen Comment 1 on mercury emissions. The waterways are beyond the scope of this project.

Comments were received from Paula Swint, by written on November 18, 2010 during the public hearing.

Comment 4:

I am concerned about the mercury…water use for this facility.

EPD Response:

Please refer to EPD's response to Citizen Comment 1 on mercury emissions.

Comments were received from Paula and John Swint, , by email on November 19, 2010.

Comment 5:

Thank you…Is there any way we could be notified if/when the company decides whether or not they will use chemicals that would make the "ash" unfit to be used for agricultural purposes?

EPD Response:

The permit requires the facility to utilize a sorbent (such as limestone, hydrated lime, or sodium bicarbonate etc.) in the duct sorbent injection system. The duct sorbent injection system is an Air Pollution Control Device designed to control acid gases (such as HCl and HF) and sulfur dioxide emissions from the biomass boiler. The ash generated from the duct sorbent injection system will be collected in the baghouse.

If the facility uses limestone or hydrated lime as a sorbent, which are both calcium based, the facility plans to sell the ash collected in the baghouse to be used for agricultural purposes. However, if sodium based sorbent is used, the facility plans to ship the ash to a permitted landfill because this ash can not be used for agricultural purposes because of the presence of sodium based compounds. This PSD permit only addresses air quality concerns and obtaining a permit for a landfill is beyond the scope of this project.

Comments were received from Chandra Brown, by email on November 19, 2010.

Comment 6:

Concerns on project Construction Timing.

EPD Response:

Condition 2.2 in the permit requires Warren County Biomass Energy Facility to commence construction on the proposed biomass-fired boiler project within 18 months of the issuance of the final PSD permit.

Comment 7:

Concerns on failure to Require Mercury Emissions Monitoring.

EPD Response:

Please refer to EPD's response to Citizen Comment 1 on mercury emissions.

Comment 8:

Concerns on increase in Particulate Matter and Potential Human Health.

EPD Response:

Please refer to EPD's response to Citizen Comment 3.

Comment 9:

Concerns on prescribed Burning.

EPD Response:

Prescribed Burning permits (to burn on a given short-term period) are currently issued by the Georgia Forestry Commission (GFC). One factor considered when issuing these permits is the local air quality. GFC reviews the ambient monitoring data for $PM_{2.5}$ to determine if burning is likely to cause a violation of the NAAQS.

The ambient monitoring station most likely to be impacted by Warren County Biomass Energy Facility is Sandersville. Prescribed burning yields high levels of particulate matter emissions, and poor dispersion since the pollution is released at ground level with no upward velocity. Particulate Matter emitted from the proposed biomass-fired boiler stack would be released from a height of several hundred feet, and have greater dispersion characteristics than prescribed burning.

$PM_{2.5}$ emissions from the this proposed facility could, in theory, have a negative impact on the amount of burning if $PM_{2.5}$ from the plant results in an increase in actual ambient monitoring results at the Sandersville station.

Air dispersion modeling was conducted to predict the ambient concentrations of pollutants due to this proposed Warren County Biomass Energy Facility. $PM_{10}/PM_{2.5}$ concentrations drop significantly more than a couple miles from the plant. Given that the Sandersville monitoring station is approximately 35 miles away from the proposed plant site, no noticeable increase in actual ambient concentrations, as monitored at this location is expected.

Comment 10:

Concerns on definition of Biomass in permit and sources.

EPD Response:

Requiring biomass feedstock certifications from different agencies is beyond the scope of this Air Quality Permit.

Comment 11:

Concerns on water use and consumption.

EPD Response:

This permit only addresses air quality concerns and water use and water consumption issues are beyond the scope of this Air Quality Permit.

Verbal Comments were received from Dianna Wedincamp, James Newsome, and Katherine Cummings during public hearing on November 18, 2010. These comments mirror the written comments received by James Newsome and Katherine Cummings.

Comment 12:

In summary, Ms. Dianna Wedincamp concerns were similar like other comment on mercury emissions, PM health issues, water consumption, prescribed burning, and wastewater treatment.

EPD Response:

Please refer to EPD’s response to Citizen Comment 1 on mercury emissions, EPD’s response to Citizen Comment 3 on potential health issues, EPD’s response to Citizen Comment 11 on water use and consumption, and EPD’s response to Citizen Comment 9 on prescribed burning.

The permit only addresses air quality concerns and wastewater treatment concerns are beyond the scope of this Air Quality Permit.

State of Florida COMMENTS

Comments were received from Alvaro Linero, Program Administrator, State of Florida, by email on November 4, 2010.

Comment 1:

This is to acknowledge receipt of and to provide comments on the Warren County Biomass Energy Facility notification provided by Georgia EPD to Jon Holtom of the Florida Department of Environmental Protection (FDEP).

In July 2010 FDEP distributed a draft PSD permit along with the technical evaluation for the Gainesville Renewable Energy Center (GREC) for a project of the same size (100 MW) and same fuel (woody biomass) as the Warren County project. The project is ahead of the Warren County project in pursuit of a final permit. Following is the link to the technical evaluation. Refer to Page 22 for the GREC emission limits.

www.dep.state.fl.us/Air/emission/bioenergy/gainesville/GRECTech.pdf

The review for the Warren County project indicated that draft permits for similar projects were reviewed in making the draft decision.

The GREC project triggered PSD for the same set of the pollutants for which the Warren County project triggered PSD.

The GREC project will have more stringent requirements than the Warren project in the following areas:

Lower nitrogen oxides (NOx) limit (0.070 lb/MMBtu for GREC on a 24-hour basis v. 0.10 lb/MMBtu for Warren on a 30-day basis)

The GREC project must install SCR (versus SNCR) to control NOx that will also reduce ammonia and hazardous air pollutants (HAP) including organic HAP such as dioxin/furan.

The GREC project must install Hydrogen chloride (HCl) and hydrogen fluoride (HF) continuous emission monitoring systems (CEMS) that help provide reasonable assurance that the project will not be a major HAP source.

Our main suggestion is that the NOx limit should be lowered to 0.07 lb/MMBtu or less and SCR installed for this size and type of project.

We note that the operators for the recently approved and similarly sized Georgia Yellow Pine facility came back and requested a lower limit of 0.07 lb/MMBtu by a circulating fluidized bed boiler by SNCR.

We do not request status as a potential party in any proceedings related to the further actions on this draft permit.

EPD Response:

Yellow Pine facility proposed to lower the NOx limit from 0.10 lbs/MMBtu to 0.07 lbs/MMBtu because the facility decided to install a circulating fluidized bed (CFB) boiler verses a bubbling fluidized bed (BFB) boiler. The BACT control technology for NOx emissions was determined to be SNCR in the Yellow Pine BACT analysis.

The Division's review of GREC project permit in Florida shows that GREC voluntarily decided to accept a NOx limit of 0.07 lbs/MMBtu and install an SCR system to control emissions. However, both the proposed NOx control technology and emissions limit does not come from BACT review. Please refer to EPD's Response to EPA Comment 3.

APPENDIX A

AIR QUALITY PERMIT

4911-301-0016-P-01-0

APPENDIX B

WRITTEN COMMENTS
RECEIVED DURING
COMMENT PERIOD