NORTH CAROLINA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DIVISION OF AIR QUALITY

PREVENTION OF SIGNIFICANT DETERIORATION PRELIMINARY DETERMINATION

WOOD BURNING IN EXISTING BOILERS

AT

LUMBERTON ENERGY, LLC
LUMBERTON, BLADEN COUNTY
NORTH CAROLINA

January 11, 2012

Mailing List

NEWSPAPER	The Robesonian 2175 N. Roberts Avenue Lumberton, NC 28359 (910) 739-4322	Public Notice
OFFICIALS	Robeson County Manager 701 N. Elm Street Lumberton, NC 28358 (910) 671-3000	Public Notice
SOURCE	Mr. Benjamin L. Ethridge, Jr. Vice President Lumberton Energy, LLC 2705 Bee Caves Road, Suite 340 Austin, TX 78746 (512) 314-8604	Preliminary Determination, Draft Permit and Public Notice
EPA	Ms. Heather Abrams Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, GA 30303-3104 (404) 562-9185	Preliminary Determination, Draft Permit and Public Notice
	Preliminary Determination and Public Notice via electronic mail to: abrams.heather@epa.gov with cc to: forney.kathleen@epa.gov worley.gregg@epa.gov	
FLM	Ms. Jill Webster US Fish and Wildlife Service Public 7333 W. Jefferson Ave., Suite 375 Lakewood, CO 80235 (303) 914-3804	None
FAYETTEVILLE REGIONAL OFFICE	Mr. Steven Vozzo Air Quality Regional Supervisor Systel Building 225 Green Street, Suite 714 Fayetteville, NC 28301 (910) 433-3300	Preliminary Determination, Draft Permit, Public Notice and Application

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Fact Sheet

Applicant:

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- Lumberton Energy, LLC, Lumberton, NC, submitted a permit application under the Prevention of Significant Deterioration (PSD) program to the North Carolina Division of Air Quality (NCDAQ) on August 16, 2010.

- The application was deemed complete by NCDAQ for review purposes pursuant to 40 CFR 51.166 (q)(1) on February 1, 2011.

- The facility is a "100 tons" category, existing, major stationary source for PSD.

- The application includes a request to burn unadulterated and adulterated wood in two, existing boilers. Adulterated wood fuels include railroad ties, engineered wood, and construction and demolition wood. The proposed modifications also include changes to the facility's fuel handling and fuel feed systems. The company is also requesting to remove the installed Mobotec control systems for reduction of NO_x and SO_2 emissions, associated with coal burning in the existing boilers. Finally, the Permittee requests a permanent shutdown of the existing lime/limestone storage silo and the associated baghouse.

- This project will result in increase in emissions of PM (17.7 tons/yr), PM_{10} (4.4 tons/yr), $PM_{2.5}$ (4.7 tons/yr), VOC (29.4 tons/yr), CO (345.7 tons/yr), H_2SO_4 (8.6 tons/yr), and GHG (233,488 CO_{2e}). Emissions of SO_2 (-808.9 tons/yr) and NOx (-78.5 tons/yr) will decrease.

- PSD Best Available Control Technology (BACT) analysis is required for emissions of CO and H_2SO_4

- NCDAQ proposes the approve the following PSD BACT emission limits and control techniques:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS	CONTROL TECHNOLOGY
Boilers (ID Nos. ES-1A and ES-1B)	CO	0.45 lb/million Btu [stack test: 3-run average]	good combustion control
	H_2SO_4	0.011 lb/million Btu [stack test: 3-run average]	use of low sulfur wood

SECTION 1.0
INTRODUCTION

Lumberton Energy, LLC (“Lumberton Energy”) has submitted to the North Carolina Division of Air Quality ("NCDAQ") a permit application (7800166.10A) under the Prevention of Significant Deterioration ("PSD") requirements of the Clean Air Act ("CAA") for its facility located in Lumberton, North Carolina. It includes a request for burning of unadulterated and adulterated wood in existing boilers (ID Nos. ES-1A and ES-1B). Adulterated wood fuels include railroad ties, engineered wood (Oriented strand board, Medium Density Fiberboard, and Plywood), and construction and demolition (C&D) wood (including building-related construction debris and demolition materials, land clearing debris, and debris generated from natural disasters including building materials and vegetative debris). The proposed modifications also include changes to the facility’s fuel handling and fuel feed systems, installation of multiclones, selective non-catalytic reduction systems and sorbent injection systems, modifications to over-fire air systems and baghouses, and addition of ammonia storage tank. The Permittee has also requested to remove the installed Mobotec control systems for reduction of NO_x and SO_2 emissions, associated with coal burning in the existing boilers. Finally, the Permittee requests a permanent shutdown of the existing lime/limestone storage silo and associated baghouse.

The permit application will be processed as per the requirements in 15A NCAC 2Q .0501(c)(2) and 15A NCAC 2D .0530 “Prevention of Significant Deterioration”. Essentially, this application will be processed as per the procedures in 15A NCAC 2Q .0300.

This facility operates under the current air permit 05543T17.

The permitted equipment at this facility are the following: two coal/natural gas/No. 2 and No. 4 fuel oils/tire-derived fuel/flyash briquette-fired boilers, two coal bunkers, one fly ash silo with wet slurry pugmill, one bottom ash silo with a retractable bulk unloading spout, two ash system vacuum transport pumps, one coal unloading/storage and transfer, and one lime/limestone storage silo.

The facility is a “100 tons” category PSD major stationary source as defined in 40 CFR 51.166(b)(1)(i)(a):

> “Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric **plant**s of more than 250 million British thermal units per hour heat input,…”.

As per EPA, the term "plant" is inclusive of all heat generating equipment[1]. Two boilers at the Lumberton Energy have 215 million Btu/hr heat input rate each. Thus, the “plant” heat input rate is 430 million Btu/hr, exceeding the cut-off value of 250 million Btu/hr. The boilers produce electric power from steam, generated due to firing fossil fuels. In addition, the facility emits or has the potential to emit of 100 tons per year each of nitrogen oxides (as NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO). Therefore, the facility is deemed a “100 tons” category, existing, major stationary source, for PSD.

The project will result in increase in emission of particulate matter (PM) (17.7 tons/yr), particulate matter less than 10 microns (PM_{10}) (4.4 tons/yr), particulate matter less than 2.5 microns ($PM_{2.5}$) (4.7 tons/yr), CO (345.7 tons/yr), volatile organic compounds (VOC) (29.4 tons/yr), sulfuric acid mist (H_2SO_4) (8.6 tons/yr), and greenhouse gases (GHG) (233,488 tons/yr CO_{2e}). However, emissions of SO_2 (- 808.9 tons/yr) and NOx (- 78.5 tons/yr) will decrease.

Only increases in emissions of CO, H_2SO_4, and GHG exceed their respective PSD significance thresholds of 100 tons/yr, 7 tons/yr, and 75,000 tons/yr CO_{2e}, respectively.

PM is not considered a “regulated NSR pollutant”, even though, EPA has established an associated “significant emission rate”.

[1] USEPA Region 5 Letter from David Kee, Director, Air and Radiation Division, to Dell Collins, Impell Power Projects, Walnut Creek, CA, September 30, 1987.

The definition of "regulated NSR pollutant" in §51.166(b)(49) reads in part, as follows:

> "Any pollutant that is subject to any standard promulgated under Section 111 of the act."

There are numerous Section 111 standards (such as NSPS) promulgated for PM for various source categories. Thus, one can conclude that PM is a "regulated NSR pollutant" under PSD. However, as per the memorandum, "Definition of Regulated Pollutant for Particulate Matter for Purposes of Title V"[2], EPA's position is that "the existing NSPS for particulate matter would serve as adequate surrogates for limiting ambient amounts of PM-10, the intended "regulated air pollutant"". EPA also believes that "the control of pollutant (such as PM) under an NSPS does not automatically result in that pollutant being considered regulated if the intended pollutant is already being regulated under the separate legal authority".

Because, PM-10 is the "intended pollutant" for control of PM emissions in various Section 111 standards (such as NSPS) and also, PM-10 is already regulated under the Section 109 of the CAA (separate legal authority), PM is not a "regulated NSR pollutant" under PSD. Hence, applicability review for PM is not required under PSD program.

The project is subject to review and processing under the NCAC 2D .0530 "Prevention of Significant Deterioration" for emissions of CO, H_2SO_4, and GHG.

With respect to GHG, EPA has deferred for a period of 3 years the application of PSD to biogenic CO_2[3] from bioenergy and other biogenic stationary sources. This deferral is effective as of July 20, 2011 for states/locals having delegated PSD programs (40 CFR 52.21). For SIP

[2] Lydia Wegman, EPA OAQPS, RTP, NC, October 16, 1995. It should be noted, however, that the other guidance issued by EPA OAQPS office were later refuted by the agency. For example, refer to December 13, 2005 letter from Steve Page, EPA OAQPS to Paul Plath, E3 Consulting, regarding IGCC as BACT. This guidance was later refuted by the EPA *In re Desert Rock Energy Company*, Slip. Op. at 68-69.
[3] It is a primary greenhouse gas within the aggregate group of six greenhouse gases. See §51.166(b)(48)(i).

approved PSD programs (40 CFR 51.166) in states/locals, such as North Carolina, this deferral is optional as per EPA. Refer to 76 FR 43490, July 20, 2011.

The State of North Carolina has completed a regulatory action to revise its SIP approved PSD program for GHG in 15A NCAC 2D .0544 to provide a similar deferral for 3 years for review of bioenergy projects for PSD applicability. Specifically, a temporary rule to defer this applicability has won the Environmental Management Commission (EMC)'s approval on November 17, 2011. In addition, the Rules Review Commission (RRC) has voted for approval of this temporary rule on December 15, 2011. Finally, this rule has become effective on December 23, 2011 and it has been codified in the North Carolina Administrative Code on this date.

Thus, a PSD review is not required for GHG emissions from the proposed project, and therefore, PSD review is required only for CO and H_2SO_4.

In addition to triggering PSD for CO and H2SO4, the Permittee is required to comply with a separate requirement for Best Available Control Technology (hereinafter "SB3 BACT") in accordance with Senate Bill 3 (Session Law 2007-397) for emissions of $PM/PM_{10}/PM_{2.5}$, SO_2, NOx, VOC, and Hg from wood-fired boilers. Refer to Sections 4.13 and 7 below for complete details.

The facility must also comply with other specific NC DAQ air pollution regulations where applicable.

Pursuant to the Federal Register notice on February 23, 1982 (47 FR 7836), North Carolina (NC) has full authority from the Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. Accordingly, the NCDAQ will conduct a full PSD review for the proposed project. NC's State Implementation Plan (SIP) - approved PSD regulations have been codified in 15A NCAC 2D .0530, which implement the requirements of 40 CFR 51.166 "Prevention of Significant Deterioration of Air Quality".

In accordance with PSD requirements, Lumberton Energy has conducted a best available control technology (BACT) analysis, source impact analysis, and additional impacts (growth, soils, vegetation, visibility) analysis.

The following emission limits and controls, as proposed by NCDAQ for approval, represent BACT:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS	CONTROL TECHNOLOGY
Boilers (ID Nos. ES-1A and ES-1B)	CO	0.45 lb/million Btu [stack test: 3-run average]	good combustion control
	H_2SO_4	0.011 lb/million Btu [stack test: 3-run average]	use of low sulfur wood

The source impact and additional impact analyses concluded that the proposed project would not cause adverse air quality impacts in the surrounding community.

1.1 Preliminary Determination

Lumberton Energy's PSD application has been reviewed by the NCDAQ, Permits Section staff, to determine compliance with the requirements of all applicable air quality regulations. The review was performed for the following:

- PSD including determination of BACT with consideration of non-PSD regulated toxic pollutants, source impact analysis, and additional impact analysis on growth, soils, vegetation and visibility;

- Compliance with the North Carolina Air Quality Rules at 15A NCAC 2D and 2Q.

The NCDAQ, Permits Section staff has conducted a preconstruction review of the application and made a preliminary determination that the proposed project will comply will all applicable

North Carolina air quality regulations including the PSD requirements. Therefore, the NCDAQ proposes to issue an air permit for the modification described in Section 1 above, with specific permit conditions and emission limits. This approval for PSD is contingent upon the following findings:

- A demonstration that BACT is applied to each new or modified emission unit that will contribute to an increase in emissions of any pollutant above the significance threshold.

- A demonstration that National Ambient Air Quality Standards (NAAQS) and PSD Class II increments will not be violated as a result of emissions from the proposed project.

- A demonstration that emissions from the proposed project will neither cause adverse impacts to soils and vegetation nor cause degradation of visibility, and that economic growth associated with the project will not cause a significant increase in regional air pollutant levels.

The remainder of this report contains a review by NCDAQ of the demonstration and analyses presented by Lumberton Energy. Sections 2 and 3 of this report present a general description of the proposed project and a description of the site location. Section 4 presents a regulatory analysis of the North Carolina and Federal air quality regulations that apply to the project construction and operation. Section 5 contains the PSD BACT analysis. Section 6 presents the results of the air quality analyses. Section 7 contains Senate Bill 3 (SB3) BACT analysis. Sample emissions calculations have been included in Appendix A while the NCDAQ draft air permit is contained in Appendix B.

In addition, the application must undergo adequate public participation. The NCDAQ solicits and encourages participation by the general public, industry, and other affected persons impacted by the proposed project. Specific public notice requirements apply and a 30-day public comment period are required before the NCDAQ can take final action on this application. Appendix C contains a copy of the public notice.

SECTION 2.0
GENERAL DESCRIPTION

2.1 Process Description

2.1.1 Existing Operations

Lumberton Energy operates a cogeneration power plant at 1866 Hestertown Road in Lumberton, Robeson County, NC. The facility has been classified under the Standard Industrial Classification (SIC) code 4911 “Electric Services”. As indicated in Section 1 above, the existing operations at the facility comprise of two coal/natural gas/No.2 and No. 4 fuel oils/tire-derived fuel/flyash briquette-fired boilers, two coal bunkers, one fly ash silo with wet slurry pugmill, one bottom ash silo with a retractable bulk unloading spout, two ash system vacuum transport pumps, one coal unloading/storage and transfer, and one lime/limestone storage silo.

The above-mentioned boilers are capable of delivering heat input rate of 215 million Btu/hr each when burning coal, thus producing a total 35 megawatts of electricity.

2.1.2 Proposed Modifications

The key elements of the proposed project are included as follows:

Authorization to Combust Biomass Fuel

This application seeks authorization to burn biomass fuel, specifically unadulterated and adulterated wood. Proposed adulterated wood fuel includes railroad ties, engineered wood (Oriented strand board, Medium Density Fiberboard, and Plywood), and C&D wood.

It needs to be stated here that proposed modifications do not include any physical changes to the boiler that can allow increased capacity or operating rate. As per the Permittee, the boilers are capable to have the same heat input rate on an annual basis (215 million Btu/hr) when firing wood after implementing modifications to facility's fuel handling and feed systems, as described below.

Proposed Changes to Fuel Yard

The existing paved plant entrance road and existing truck scales will be used for receiving biomass fuels. An additional lane will be added to the entrance road by the truck scales to prevent congestion. A new truck dumper (Truck Dumper No. 1), complete with a receiving hopper, will be located in the existing plant yard in an area previously used for coal storage. A truck dumper (Truck Dumper No. 2 [Future]) to be added at a future date is also proposed.

Biomass will be processed through a screen after discharging from the truck dumper hopper. Accepted materials will be conveyed to a reversing conveyor that will transport the biomass to either (1) an automated fuel house that will meter fuel onto conveyors feeding the boilers, or (2) a conveyor delivering fuel to storage piles. Fuel will be moved onto and off of the storage piles with a front end loader or bulldozer. The storage piles will be located in an area that will be cleared of trees and covered with clean fill. The fuel storage and metering building will be located in an area previously used for coal storage. One new conveyor and one relocated conveyor will transport biomass from the storage and metering building to the boilers. Each boiler feed conveyor will have a biomass screen. All screen rejects will periodically be re-processed and placed back into the fuel piles. The fuel storage yard will have a gravel surface. The area between the storage piles and the storage building will be paved.

Proposed Changes to Fuel System Inside Plant

The supply conveyors will discharge an average of 21.2 tons of solid fuel per hour per boiler onto a new distribution conveyor for each boiler. The distribution conveyors, which will be inside the boiler house, will supply fuel to three new two-screw metering bins for each boiler. Excess fuel will be returned to the feed conveyors by way of an over-feed elevating conveyor. Fuel from the metering bins will drop into new chutes for delivery of fuel to new windswept distributors, which feed fuel to the boilers.

Proposed Changes to Bottom Ash and Sifting Ash Collection

The existing bottom coal ash and sifting ash systems will be removed from the boilers. New wet bottom biomass ash systems will be installed on each boiler. Mechanical sifting ash conveyors will be installed to convey sifting ash from four hoppers to the bottom ash system. New conveyors will transport wet bottom ash to an outdoor storage bunker. Water will be collected in a sump and returned to the boilers for use in the wet bottom ash system. An existing lime storage silo will be removed to provide space for the ash bunker.

Proposed Changes to Over-Fire Air (OFA) System

The OFA system on the boilers will be modified by the addition of over-fire air ports on the rear wall of the boiler. A secondary air fan will be installed on each boiler to provide air to the rear OFA ports, the existing front OFA ports, and the windswept fuel distributors.

Proposed Additions of Mechanical Dust Collectors

New mechanical dust collectors will be installed between the air heaters and the bag houses on each boiler. The mechanical dust collectors will be multi-cyclones. Ash from the mechanical collectors will be mechanically conveyed with new dust-tight conveyors to the bag house ash collection system. The mechanical collectors will be installed to allow future installation of equipment to re-inject collected char to the boilers. Due to the increased pressure drop through the dust collectors, the induced draft fans and motors will be replaced and equipped with variable speed drives. The existing ID fan foundations will be reworked to fit the larger fans. Guillotine isolation gates will be installed at the shared stack to allow isolation of either boiler.

Proposed Changes to Baghouses

The existing baghouses will be equipped with new pleated bags to increase the filtering area by up to 100%. The pleated bags will be shorter than the previous un-pleated bags. The shorter length reduces abrasion of the bottom of the bags and allows significantly more flexibility in the installation of the new ash removal system. The baghouse discharge hoppers will be modified, without having to move the baghouses, to provide space to allow the replacement of the existing slide gates with new rotary valves. An isolation valve and expansion joint will also be added at each hopper. The existing pneumatic conveying system will be demolished and replaced with new mechanical conveyors. These collector conveyors will discharge ash from the mechanical dust collectors and the baghouses into a single elevating conveyor, which will lift ash into an ash storage bin. The existing ash storage silos will be removed and the bottom of one silo will be converted into a bin. The modified ash silo will be equipped with an evacuation fan and filter system to maintain negative pressure in the ash bin and prevent fugitive dust emissions. The ash will then be processed through the existing pug mill. Conditioned ash will drop into a new concrete bunker. It will also be able to drop directly into a truck or roll-off container.

Proposed Addition of Selective Non-Catalytic Reduction (SNCR) System

A selective non-catalytic reduction (SNCR) system will be added to each boiler to reduce NO_x emissions. The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_X in the exhaust gas stream with the injected aqueous ammonia (NH_3), yielding nitrogen and water vapor. The ammonia reagent will be injected into the post combustion flue gas where the flue gas temperature is at the necessary temperature range (i.e., between 1600°F and 2100°F) for the chemical reduction process to occur. Reagent will be injected into the flue gas through nozzles mounted on the wall of the boilers. SNCR installation may require modification or relocation of ductwork and other boiler equipment.

Proposed Addition of Aqueous Ammonia (< 19 wt%) Storage and Handling

The SNCR system includes aqueous ammonia storage, distribution and injection equipment. Aqueous ammonia will arrive on-site by tank truck. The truck will be off-loaded into an atmospheric tank equipped with water scrubbing (goose neck type) seal for storage. The aqueous ammonia will then be pumped from the storage vessel to an ammonia injection skid via aboveground piping. The aqueous ammonia will be injected through a series of nozzles into the boiler flue gas.

Proposed Addition of Sorbent Injection System

A dry sorbent injection system will be added to each boiler to control opacity on an as-needed basis. A sodium-based dry alkaline sorbent is to be injected in the ductwork between the mechanical dust collector and the baghouse. The reaction products are then removed in the baghouse. Sodium bicarbonate or sodium sesquicarbonate (i.e., trona) will be used as the sorbent.

Gaseous mixtures of ammonia slip from the SNCR process and hydrogen chloride (HCl) from boiler exhaust may form ammonium chloride when cooled below ~235°F resulting in a detached white, opaque plume. Formation of the plume is dependent on the chloride content in the fuel. The sorbent injection system will be operating only when needed to control opacity.

Other Changes

The Permittee has requested to remove the permitted Mobotec control systems for reduction of NO_x (ROFA) and SO_2 emissions (ROTAMIX) from the existing boilers. The Mobotec systems were designed and permitted to control emissions while burning coal. These systems will be removed as part of this modification. It should be emphasized here that the without the above control equipment, the Permittee is expected to burn cleaner coal (such as low sulfur coal) in order to comply with the various regulatory requirements.

Finally, the Permittee requests a permanent shutdown of the existing lime/limestone storage silo and the associated baghouse.

2.2 Emissions

Emissions from Lumberton Energy facility include PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, and GHG. A detailed emission summary for actual emissions and emissions increases/decreases due to proposed project are included in Section 4.

SECTION 3.0
REGIONAL DESCRIPTION

3.1 Area Classification

The facility is located two miles south of Lumberton in Robeson County. The facility coordinates are 34º 59' 00" (latitude) and 78º 59' 41" longitude). The area is classified as "rural" based on the land use scheme established by Auer 1978.

Air Quality in Robeson County is classified with respect to the NAAQS as listed below:

Pollutant	**Attainment Status**
PM_{10}	Attainment
$PM_{2.5}$	Attainment
Sulfur Dioxide	Attainment
Nitrogen Dioxide	Attainment
Carbon Monoxide	Attainment
Ozone	Attainment
Lead	Attainment

Robeson County is considered a Class II Area with ambient air increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_x.

The closest Class I Area from this facility is the Cape Romain National Wildlife Refuge, which is located approximately 170 km southeast to the facility.

SECTION 4.0
REGULATORY ANALYSIS

The following discussion pertains to the regulatory requirements that must be met for the proposed modification of the Lumberton Energy facility. These requirements include PSD regulations and other State and federally enforceable air quality regulations.

4.1 PSD Applicability and Required Analysis

The basic goal of the PSD regulations is to ensure that the air quality in attainment areas (e.g., Robeson County, NC, for PM_{10}, $PM_{2.5}$, NOx (as NO_2), SO_2, CO, ozone, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth. The PSD regulations focus on industrial facilities, both new and modified major sources.

Under PSD requirements, all major new or modified stationary sources of air pollutants as defined in §169 of the CAA must be reviewed and permitted, prior to construction, by EPA or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28 named source categories (e.g., “fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input”), which emits or has a potential to emit (PTE) 100 tons per year of any “regulated NSR pollutant”, or any other stationary source, which emits or has the potential to emit 250 tons per year of any “regulated NSR pollutant”.

As stated in Section 1 above, Lumberton Energy facility is an existing “major stationary source”, classified under the category of “fossil-fueled fired steam electric plants of more than 250 million Btu per hour heat input”, in accordance with §51.166(b)(1)(i). That is, this facility emits or has the potential to emit of 100 tons per year or more of any regulated NSR pollutant. In fact, the facility has the potential to emit more than 100 tons per year of nitrogen oxides (as NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO) each.

Because the existing facility is considered a major stationary source, any modification to an existing major source resulting in significant emission increases for any regulated NSR pollutants, is subject to PSD review, and must meet appropriate review requirements. Thus, the emission increases as a result of this modification must be compared to the "significance levels", as listed in 40 CFR 51.166(b)(23)(i), to determine which pollutants must undergo PSD review.

The Permittee has performed a PSD applicability analysis by determining whether the project results in an emission increase of any regulated NSR pollutant above the respective significance thresholds.

Using the "actual-to-projected actual test", the Permittee has performed calculations for actual (pre-change) and projected actual (post-change) emissions for all regulated NSR pollutants. The actual emissions for the existing emissions units (such as boiler ES-1A burning coal) have been estimated for the time period 2002-2003 and have been referred to as the baseline emissions.

The requirement in 15A NCAC 2D .0530 provides that the Permittee can choose any consecutive 24-month as a baseline period from the look-back period of 5 years from the date of the receipt of the complete application. This regulation also specifies that the Director can allow a different look-back period not to exceed 10 years immediately preceding the date of the receipt of the complete application, if the Permittee can demonstrate that it is more representative of normal source operation. This application was deemed complete as of February 1, 2011. So, the 5-year and 10 year look-back periods encompass the periods of February 1, 2006 - February 1, 2011 and February 1, 2001 - February 1, 2011, respectively. The Permittee has chosen to use the look-back period of 10 years. It contends that during the immediate 5-years of look-back (2005-2009), the facility had experienced sporadic and limited operation, and thus, it had produced electric power for only 20% of the maximum operating hours (8760 hrs). In addition, it should also be noted that the facility had not operated for any hours during 2010 and 2011. DAQ believes that the facility's operations in the last several years (2005-2011) do not represent the "normal source operation". DAQ further believes that the Permittee has provided adequate basis to justify the use of 10-year look-back period, and thus, it would allow the Permittee to use the look-back period beyond the 5 years immediately preceding the receipt of the completed application.

The projected actual emissions for these emissions units have been estimated using the "potential to emit" concept. For example, the projected actual emissions of the modified boiler ES-1A have been based upon 8,760 hours of operation per year, burning wood at a maximum rate of 215 million Btu per hour, and proposed BACT limits, AP-42 emissions factors and the actual stack tests results of a similar boiler.

Table 4-1 Emission Increases for the Proposed Project

Regulated NSR Pollutant	Significant Emission Rate Tons Per Year	Emissions Increase/Decrease Tons Per Year	Major Modification Review Required?
PM	25	17.7	No
PM_{10}	15	4.4	No
$PM_{2.5}$	10	4.7	No
SO_2	40	- 808.9	No
NOx (as NO_2)	40	- 78.5	No
CO	100	345.7	**Yes**
VOC	40	29.4	No
Lead	0.6	Decrease	No
Sulfuric Acid Mist	7	8.6	**Yes**
GHG	75,000 CO_{2e}	233,488.0 CO_{2e}	**No**

Using this procedure and as shown in Table 4-1 above, the following can be concluded:

- The change in emissions due to the project for CO, sulfuric acid mist, and GHG will exceed their respective PSD significance thresholds, and hence, PSD major modification review may be required for these pollutants. However, as discussed above in Section 1, PSD review is required only for CO and H_2SO_4.

- For some other pollutants; PM, PM_{10}, $PM_{2.5,}$ VOC, and lead, the change in emissions due to the project will be less than their respective PSD significance thresholds, and thus PSD major modification review is not required for these pollutants. As noted above in Section 1, PM is not a "regulated NSR pollutant". Finally, the emissions of SO_2 and NOx (as NO_2) will decrease.

Thus, Lumberton Energy has performed the following reviews and analyses related to PSD for emissions of CO and sulfuric acid mist from the proposed changes. These reviews and analyses are required to be performed for each affected new or modified emission unit causing or contributing to an emission increase of any regulated air pollutant equaling or exceeding its significance threshold, as per 15A NCAC 2D .0530.

- BACT determination
- source impact analysis
- air quality analysis
- additional impacts analysis including effects on soils, vegetation, and visibility.

Under PSD regulations, the determination of the necessary emission control equipment is developed through a BACT review. BACT is defined, in pertinent part, at 40 CFR 51.166 (b)(12) as:

> *An emissions limitation... based on the maximum degree of reduction for each pollutant... which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environment, and economic impacts and other costs, determines is achievable... for control of such a pollutant.*

The BACT requirements are intended to ensure that the control systems incorporated in the design of the proposed facility reflect the latest control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the facility. Under the BACT requirements of the PSD regulations, all BACT emission limits must, at a minimum, comply with any applicable standard of performance under 40 CFR Part 60 (New Source Performance Standards) and Part 61 (National Emission Standards for Hazardous Air Pollutants), and the North Carolina State Implementation Plan (SIP). A discussion of the BACT determination for the proposed project can be found in Section 5 of this document.

4.2 NCDAQ Air Pollution Regulations

In addition to the PSD requirements, the NCDAQ has promulgated air quality rules under Title 15A NCAC Subchapters 2D and 2Q.

The NCDAQ permitting and emission control regulations that affect the proposed modification are summarized below:

Regulation	Affected Sources	Comment
2Q .0101	Two boilers (ID Nos. ES-1A and ES-1B)	A permit is required for all sources of air emissions not specifically exempted. These sources (modified boilers) are processed under the 2Q .0300 program. They are required to be permitted with specific conditions and cannot be categorized as insignificant emission sources under 2Q .0503(7) or (8).
2D .0504	Two boilers (ID Nos. ES-1A and ES-1B)	Allowable particulate matter emissions from the wood-fired boilers are based upon the maximum heat input rate of all wood burning indirect heat exchangers.
2D .0516	Two boilers (ID Nos. ES-1A and ES-1B)	Allowable SO_2 emissions from these sources shall not exceed 2.3 lbs/million Btu heat input rate.
2D .0521	Two boilers (ID Nos. ES-1A and ES-1B)	Visible emissions cannot exceed 20 percent opacity from each of these boilers when burning wood.
2D .0524	Two boilers (ID Nos. ES-1A and ES-1B)	Burning of wood does not result into "modification" of the boilers, in the context of Section 60.14. In addition, these boilers do not meet the requirements of Section 60.15 "reconstruction". Thus, these existing boilers when burning wood are NOT subject to NSPS Subpart Db requirements.

2D .0530	Two boilers (ID Nos. ES-1A and ES-1B)	PSD review is required for a major modification.
2D .0535	Two boilers (ID Nos. ES-1A and ES-1B)	Emissions in excess of established permit limits that last for more than 4 hours require notification to the Director within 24 hours.
2D .1100	Two boilers (ID Nos. ES-1A and ES-1B)	Approved emissions limits for modeled toxic air pollutants shall not be exceeded.
2D .1111	Two boilers (ID Nos. ES-1A and ES-1B)	These sources must comply with the promulgated standards for “area sources”.
2D .2400	Two boilers (ID Nos. ES-1A and ES-1B)	These boilers are currently subject to the Clean Air Interstate Rules when burning fossil fuels. Acid Rain program. However, they are NOT subject to the requirements of this regulation when burning wood.
2Q .0317	Two boilers (ID Nos. ES-1A and ES-1B)	Facility wide emissions of HAP must be less than 10 tons/yr (single HAP) and 25 tons/yr (aggregate HAP).
2Q .0400	Two boilers (ID Nos. ES-1A and ES-1B)	These boilers are currently subject to the Acid Rain rules when burning fossil fuels. However, they are NOT subject to the requirements of this regulation when burning wood.
Senate Bill 3 (Session Law 2007-397)	Two boilers (ID Nos. ES-1A and ES-1B)	These boilers must comply with the BACT requirements of this law.

4.2.1 15A NCAC 2Q .0101 - Required Air Quality Permits

This regulation requires the owner or operator of any source for which there is an applicable standard, requirement, or rule, that is not exempted from permit requirements, to apply for an air quality permit. The owner or operator of a source required to have a permit shall not begin construction or operation of the source without first obtaining a permit. The proposed modifications to the existing boilers (ID Nos. ES-1A and ES-1B) are not exempt from permitting. Thus, Lumberton Energy is required to file an air permit application and obtain a revised permit prior to burning wood in these sources. The Permittee has submitted the required application and information sufficient to obtain an air quality permit, including all information required pursuant to 15A NCAC 2D .0530 "Prevention of Significant Deterioration".

4.2.2 15A NCAC 2D .0504 - Particulates from Wood Burning Indirect Heat Exchangers

Allowable particulate matter emissions (filterable only) from burning of wood in the boilers shall be determined as follows:

$E = 1.1698 * Q^{-0.2230}$

where, E = allowable PM emission limit in lb/million Btu

Q = total maximum heat inputs of all wood firing indirect heat exchangers at the site in operation, under construction or permitted, million Btu/hr

= (215 x 2) million Btu/hr
= 430 million Btu/hr

Hence, E = 0.30 lb/million Btu when burning wood only.

The Permittee has estimated an emission rate for PM (filterable and condensable) emission of 0.015 lb/million Btu burning wood considering the control efficiencies of multiclone and bagfilter. Hence, compliance with the above allowable emission limit is expected.

In addition, when the fuel burning equipment is burning wood in combination of other fuel(s), then PM allowable emission limit is calculated as follows:

Ec = [(Ew)(Qw) + (Eo)(Qo)] / Qt

where, Ec = the emission limit for combination or combined emission source(s) in lb/million Btu

Ew = the plant site emission limit for wood only as determined by Rule .0504 of this Section in lb/million Btu

Eo = the plant site emission limit for other fuels only as determined by Paragraphs (a), (b) and (c) of Rule .0503 in lb/million Btu

Qw = the actual wood heat input to the combination or combined emission source(s) in Btu/hr

Qo = the actual other fuels heat input to the combination or combined emission source(s) in Btu/hr

Qt = Qw + Qo and is the actual total heat input to combination or combined emission source(s) in Btu/hr

As per the current permit, Eo = 0.23 lb/million Btu and as shown above, Ew = 0.30 lb/million Btu.

Hence, PM allowable emission limit on a combined basis will be,

Ec = [(0.30)(Qw) + (0.23)(Qo)]/Qt lb/million Btu

4.2.3 15A NCAC 2D .0516 - Sulfur Dioxide Emissions from Combustion Sources

Emission of sulfur dioxide from any source of combustion that is discharged from any vent, stack, or chimney shall not exceed 2.3 pounds of sulfur dioxide per million BTU input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard. Sulfur dioxide formed or reduced as a result of treating flue gases with sulfur trioxide or other materials shall also be accounted for when determining compliance with this standard.

A source subject to an emission standard for sulfur dioxide in Rules 2D .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 of 15A NCAC shall meet the standard in that particular rule instead of the standard in the above paragraph.

The modified boilers are not subject to any of the Rules in 2D .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 for sulfur dioxide, so it is subject to the requirements in 2D .0516.

The Permittee has estimated an emission limit of 0.14 lb/million Btu based upon fuel sulfur content in wood and assuming that all sulfur in wood will end up as SO_2 at the stack level. Hence, compliance with the emission standard of 2.3 lb/million Btu is expected.

4.2.4 15A NCAC 2D .0521 - Control of Visible Emissions

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where visible emissions can be reasonably expected to occur, except during startup, shutdowns, and malfunctions approved as such according to procedures approved under 15A NCAC 2D .0535.

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install, operate, and maintain continuous opacity monitoring systems (COMS), compliance with the 20 percent opacity limit shall be determined as follows:

i. No six-minute period exceeds 87 percent opacity;
ii. No more than one six-minute period exceeds 20 percent opacity in any hour; and
iii. No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

Excess emissions during startup and shutdown shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(c).

All periods of excess emissions shall be included in the determinations in paragraphs i. and ii. above, until such time that the excess emissions are exempted according to the procedures in 2D .0535.

These modified boilers, when burning wood, are subject to this 20 percent opacity standard. Compliance will be verified after the commencement of operation.

4.2.5 15A NCAC 2D .0524 - New Source Performance Standards

NSPS Section 60.14 “Modification”

Any physical or operational change to an existing facility, which results in an increase in emission rate of any pollutant to which a standard applies shall be considered a modification within the meaning of §111 of CAA.

The proposed burning of wood is clearly an operational change and hence, any increase in emissions due to wood burning needs to be investigated for emission increase for any pollutant for which standard applies.

EPA has promulgated New Source Performance Standard (NSPS) in Subpart Db for each steam generating units which commence construction, reconstruction or modification after June 19, 1984, and that has a heat input capacity of greater than 100 million Btu/hr. This NSPS includes emission standards for PM (filterable) and NOx when firing wood. The NSPS also includes emission standard for SO_2 for fuels other than wood.

The Permittee has provided the pre-change (coal burning) and the post-change (wood burning) emissions analysis for these two pollutants, considering the maximum potential emissions in each scenario.

Boiler ID	Maximum Design Heat Input Capacity million Btu/hr	Current Maximum Heat Input Capacity million Btu/hr	Pollutant	Pre-change Maximum Emission Rate lb/hr	Post-change Maximum Emission Rate lb/hr	Boiler Deemed to be "Modified" under §60.14?
ES-1A	215	215	PM (filterable only)	5.29	3.23	No
			NOx	55	26.88	No
ES-1B	215	215	PM (filterable only)	5.29	3.23	No
			NOx	55.08	26.88	No

The pre-change PM (filterable only) maximum emission rate is based upon an emission factor of 0.0246 lb/million Btu burning coal (historic emission factor used for coal burning in the annual emission inventories submitted to DAQ) while the pre-change NOx maximum emission rate is based upon the NOx emission rate burning coal for 2009 (CEM data reported to EPA's Clean Air Markets Division). The post-change maximum emissions rates are based upon the proposed emissions limits of 0.015 lb/million Btu (PM filterable) and 0.125 lb/million Btu (NOx) for PM and NOx, respectively. Finally, this NSPS applicability procedure follows the EPA guidance included in 57 FR 32330, July 21, 1992 ("WEPCO rule"). Thus, it can be seen in the above Table, that the "modification" is not triggered for any of these pollutants. Hence, NSPS Subpart Db does not apply to these boilers when burning wood.

In addition, the proposed modifications do no trigger the "reconstruction" provision in §60.15, as the fixed capital cost of the new components do not exceed the 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Thus, the existing boilers do not become "affected facility" under NSPS Subpart Db.

Separately, Section 129(g)(1) of the CAA includes an exclusion for qualifying small power production facilities (as defined in Section 3(17)(C) of Federal Power Act) burning homogeneous waste, from "solid waste incineration units" definition.

The Permittee has concluded that the boilers at the Lumberton Energy burning wood are not "solid waste incineration units" because they are "qualifying small power production facilities". It intends to provide a "self-certification" under the Federal Power Act deeming the facility "small power production facility". The Permittee also states that it intends to burn only "homogeneous" waste in these boilers.

But, based on all the information provided by the Permittee on various wood fuels, DAQ is not able to conclusively determine whether the proposed wood fuels (engineered wood, construction and demolition (C&D) wood or railroad ties) are either "solid waste" or "homogeneous", and thus, whether they are subject to applicable requirements in Commercial/Industrial Solid Waste

Incinerators (CISWI) NSPS (Subpart CCCC or Subpart DDDD). Thus, DAQ will limit the wood burning in two, existing boilers, to "non-CISWI subject wood" only. After obtaining a PSD permit for the "non-CISWI subject wood" for these boilers, the Permittee still has an option to submit a request for applicability determination for CISWI NSPS to DAQ for specific wood types, as described above.

4.2.6 15A NCAC 2D .0530 - Prevention of Significant Deterioration

Facilities classified as major for PSD and applying for a significant modification are subject to all the requirements as defined in 15A NCAC 2D .0530. These requirements include:

- A demonstration that BACT is applied to each emission unit that will emit any PSD regulated pollutant that is emitted above the significant threshold.
- A demonstration that neither allowable PSD ambient air increments nor NAAQS will be violated as a result of the emissions from the proposed project.
- A demonstration that emissions from the proposed project will neither cause adverse impacts to soils and vegetation nor cause degradation of visibility, and that economic growth associated with the project will not cause a significant increase in regional air pollutant levels.
- A demonstration that air emissions resulting from the proposed facility will not adversely impact any PSD Class I area.

For additional details on the PSD regulatory analysis, please refer to Section 4.1 above.

4.2.7 15A NCAC 2D .0535 - Excess Emissions Reporting and Malfunctions

This regulation applies to all permitted facilities and outlines the procedures of reporting excess emissions as a result of malfunctions or operational upsets. The facility owner/operator must notify the appropriate regional office of any excess emissions that last for greater than four hours. This report must be made within 24 hours of becoming aware of the occurrence.

4.2.8 15A NCAC 2D .1100 - Control of Toxic Air Pollutants

No person shall cause or allow any toxic air pollutant included in 2D .1104 to be emitted into the atmosphere at a rate that exceeds the applicable rate(s) in rule 2Q .0711 without having received a permit to emit toxic air pollutants.

As per the current permit, the facility-wide actual emissions of cadmium and nickel were evaluated in February 1996 and were found to be less than the applicable toxic air pollutant emission rates in 2Q .0711.

"Modifications" provision in 2Q .0706 can trigger an air toxics review, if there is a net emission change in any toxic air pollutant that the facility was emitting before the modification or emissions of any toxic air pollutant that the facility was not emitting before the modification if such emissions exceed the levels contained in 2Q .0711.

For the proposed changes, the Permittee has evaluated facility-wide emissions of all air toxics expected to be emitted from these boilers and any other combustion equipment. The Permittee has submitted a modeling demonstration to comply with the Acceptable Ambient Levels (AALs) for acrolein, ammonia, arsenic, benzene, benzo(a)pyrene, beryllium, cadmium, chlorine, soluble chromate compounds as chromium VI equivalent, formaldehyde, hexchlorodibenzo-p-dioxins, hydrogen chloride, manganese, mercury vapor, nickel, sulfuric acid, tetrachlorodibenzo-p-dioxin, vinyl chloride. Refer to Section 6.0 for complete details.

4.2.9 15A NCAC 2D .1111 - Maximum Achievable Control Technology

National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources [40 CFR 63 Subpart JJJJJJ]

EPA has promulgated the “area source” MACT and GACT for industrial/commercial/institutional boilers in 40 CFR 63 “National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources” on March 21, 2011 with an effective date of May 20, 2011.

Lumberton Energy facility is an “area source” as defined in Part 63. The Permittee has analyzed the above regulatory requirement. The following includes a summary of the applicable requirements.

Applicability

The boilers were constructed prior to June 4, 2010, and the proposed changes (wood burning in the boilers) do not meet the definition of reconstruction pursuant to §63.2 because the fixed capital cost of the new components does not exceed 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Therefore, the boilers are existing sources in accordance with §63.11194(b).

The boilers are expected to burn at least 15 percent biomass on an annual heat input basis after the DAQ authorizes to burn unadulterated and adulterated wood fuels in the boilers. The boilers are therefore expected to be within the biomass subcategory. The requirements for existing biomass boilers are discussed below.

The boilers will continued to be authorized to burn solid fossil fuel (including coal and tire derived fuel) even after the authorization to burn wood fuels is approved. If the boilers burn no more than 15 percent biomass on an annual heat input basis, they will be within the coal subcategory and will be subject to different requirements than the applicable requirements for existing biomass boilers. The requirements for existing coal boilers are also discussed below.

Existing Biomass Boilers Subcategory

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices for Existing Biomass Boilers

Existing biomass boilers are to comply with the following standards in accordance with §63.11201, and Tables 1, 2 and 3 of Subpart JJJJJJ:

- Tables 1, Emission Limits – There are no applicable emission limits for existing biomass boilers.

- Table 2, Work Practice Standards
  - Conduct a tune-up of the boiler biennially as specified in §63.11223; and
  - Conduct a one-time energy assessment performed by a qualified energy assessor.

- Tables 3, Operating Limits – Operating limits only apply for boilers with emission limits. Therefore, operating limits are not applicable.

General Compliance Requirements

The boilers, including associated air pollution control equipment and monitoring equipment, are to be operated and maintained at all times in a manner consistent with safety and good air pollution control practices for minimizing emissions in accordance with the general compliance requirements per §63.11205.

Initial Compliance Requirements for Existing Biomass Boilers

There are no applicable emission limits for existing biomass boilers. Therefore, performance testing to demonstrate compliance with emission limits is not required.

Existing affected boilers are to demonstrate compliance with applicable work practice standards, management practices, or emission reduction measures no later than the compliance dates specified in §63.11196. Compliance with the requirement to conduct a biennial performance tune-up is to be achieved no later than March 21, 2012. Compliance with the one-time energy assessment requirement is to be achieved no later than March 21, 2014.

Initial Compliance Demonstration with Work Practice Standards, Emission Reduction Measures, and Management Practices for Existing Biomass Boilers

A signed statement in the Notification of Compliance Status report is to be submitted that indicates that a tune-up of the boilers was conducted according to §63.11223(b). Also, a signed statement in the Notification of Compliance Status report is to be submitted that an energy assessment of the boiler and its energy use systems was completed. The energy assessment report is to be submitted upon request.

Demonstration of Continuous Compliance with Work Practice and Management Practices Standards for Existing Biomass Boilers

Biennial performance tune-ups are to be conducted according to §63.11223(b), and records maintained as required in §63.11225(c) to demonstrate continuous compliance. Each biennial tune-up is to be conducted no more than 25 months after the previous tune-up.

Monitoring, Installation, Operation, and Maintenance Requirements for Existing Biomass Boilers

There are no applicable monitoring, installation, operation, or maintenance requirements because there are no applicable emission limits or operating limits for existing biomass boilers.

Notification, Reporting, and Recordkeeping Requirements for Existing Biomass Boilers

The following notifications and reports are required for existing biomass boilers in accordance with §63.11225:

- Submit Initial Notification no later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard) as specified in §63.9(b)(2);

- Submit Notification of Compliance Status in accordance with §63.9(h) no later 120 days after the applicable compliance date specified in §63.11196;

- An annual compliance certification report is to be prepared by March 1 of each year for the previous year containing the information specified in §63.11225(b)(1) through (4). The report is to be submitted by March 15 if the source experiences any deviations from the applicable requirements during the reporting period.

Records are to be maintained as specified in §63.11225(c)(1) through (5).

Existing Coal Boilers Subcategory

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices for Existing Coal Boilers

Existing coal boilers (with heat input capacity greater than 10 million Btu/hr) are to comply with the following standards in accordance with §63.11201, and Tables 1, 2 and 3 to Subpart JJJJJJ:

- Table 1, Emission Limits
  - Mercury – 0.0000048 lb/million Btu of heat input; and
  - Carbon Monoxide (CO) – 400 ppm by volume on a dry basis corrected to 3% O_2.

- Table 2, Work Practice Standards
  - Minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures;

- Conduct a tune-up of the boiler biennially as specified in §63.11223; and
- Conduct a one-time energy assessment performed by a qualified energy assessor.

- Table 3, Operating Limits
  - Maintain the operating load of each unit so that it does not exceed the 110% of the average operating load recorded during the most recent stack test;
  - Maintain the oxygen level at or above the lowest 1-hour average oxygen level measured during the most recent CO performance stack test;
  - Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rates calculated according to §63.11211(b) is less than the applicable emission limit for mercury (if demonstrating compliance with the mercury emission limit using fuel analysis); and
  - Either maintain opacity less than 10% (daily block average), or install and operate a bag leak detection system according to §63.11224 (if demonstrating compliance with the mercury emission limit using fabric filter control).

General Compliance Requirements

The boilers, including associated air pollution control equipment and monitoring equipment, are to be operated and maintained at all times in a manner consistent with safety and good air pollution control practices for minimizing emissions in accordance with the general compliance requirements per §63.11205.

Develop a site-specific monitoring plan according to the requirements specified in §63.11205(c)(1) through (3) for the use of the O_2 continuous monitoring system (CMS) used to demonstrate compliance with CO emission limits. Operate and maintain the CMS according to the site-specific monitoring plan.

Initial Compliance Requirements for Existing Coal Boilers

Demonstrate initial compliance with the emission limits for mercury and carbon monoxide either by conducting stack testing according to §63.11212 and Table 4 to Subpart JJJJJJ or, for mercury, conducting fuel analyses, as applicable, according to §63.11213 and Table 5 to Subpart JJJJJJ.

Demonstrate initial compliance with applicable emission limits, and work practice standards, management practices, or emission reduction measures no later than 180 days after the compliance dates specified in §63.11196 and according to the applicable provisions in §63.7(a)(2). Compliance with the requirement to conduct a biennial performance tune-up is to be achieved no later than March 21, 2012. Compliance with emission limits and the one-time energy assessment requirement are to be achieved no later than March 21, 2014.

Initial Compliance Demonstration with Emission Limits

For affected boilers that demonstrate compliance with applicable emission limits through stack testing:

- Conduct stack testing according to §63.11212 and Table 4 to Subpart JJJJJJ to demonstrate compliance with applicable emission limits;

- Conduct a fuel analysis for each type of fuel burned in the boiler that is subject to emission limits for mercury according to §63.11213 and Table 5 to Subpart JJJJJJ (if electing to demonstrate compliance with mercury emission limit through fuel analysis); and

- Establish parameter operating limit for boilers with fabric filters (if continuous compliance with the mercury emission limit is to be demonstrated through a bag leak detection system) according to §63.11211(b)(4).

Initial Compliance Demonstration with Work Practice Standards, Emission Reduction Measures, and Management Practices for Existing Coal Boilers

A signed statement in the Notification of Compliance Status report is to be submitted that indicates that a tune-up of the boilers was conducted according to §63.11223(b). Also, a signed statement in the Notification of Compliance Status report is to be submitted that an energy assessment of the boiler and its energy use systems was completed. The energy assessment report is to be submitted upon request.

Demonstration of Continuous Compliance with Emission Limits for Existing Coal Boilers

Demonstrate continuous compliance with applicable emissions limits and operating limits in Tables 1 and 3 to Subpart JJJJJJ in accordance with §63.11222 as follows:

- Continuously monitor the required operating parameters. Operation outside the established allowable range of the operating limits constitutes a deviation from the established operating limits.

- Maintain records of the type and amount of all fuels burned in each boiler to demonstrate that all fuel types and mixtures burned result in lower emissions of mercury than the applicable emission limit (if demonstrating compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last stack test (if demonstrating compliance through performance stack testing).

- Initiate corrective action within hour of a bag leak detection system alarm, and operate the fabric filter system such that the alarm does not sound more than 5 percent of the operating time (if continuous compliance with the mercury emission limit is to be demonstrated through a bag leak detection system).

Demonstration of Continuous Compliance with Work Practice and Management Practices Standards for Existing Coal Boilers

Biennial performance tune-ups are to be conducted according to §63.11223(b), and records maintained as required in §63.11225(c) to demonstrate continuous compliance. Each biennial tune-up is to be conducted no more than 25 months after the previous tune-up.

Continuous Compliance Requirements

Subsequent performance tests to demonstrate compliance with applicable emission limits are to be conducted every three (3) years. Each triennial performance test is to be conducted no more than 37 months after the previous performance test.

If electing to demonstrate compliance with mercury emission limits based on fuel analysis, conduct a monthly fuel analysis according to §63.11213 for each type of fuel burned that is subject to emission limits for mercury.

Monitoring, Installation, Operation, and Maintenance Requirements for Coal Biomass Boilers

Comply with the applicable monitoring, installation, operation, or maintenance requirements according to §63.11224 as follows:

- Install and operate a continuous oxygen monitor in accordance with §63.11224(a)(1) through (6);

- Either install and operate a bag leak detection system, and operate the fabric filter according to §63.11224(f)(1) through (8) such that the requirements of §63.11222(a)(4) are met (if continuous compliance with the mercury emission limit is to be demonstrated through a bag leak detection system), or install, certify and operate a continuous opacity monitoring system (COMS) according to the procedures of §63.11224 (e)(1) through (7); and

- Develop a site-specific monitoring plan according to the requirements of §63.11224(c)(1) through (4) (if demonstrating compliance with applicable emission limits through stack testing and subsequent compliance with operating limits).

Notification, Reporting, and Recordkeeping Requirements for Existing Coal Boilers

The following notifications and reports are required for existing coal boilers in accordance with §63.11225:

- Submit Notification of Intent to conduct a performance stack test at least 60 days before the stack test is scheduled to begin;

- Submit Initial Notification no later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard) as specified in §63.9(b)(2);

- Submit Notification of Compliance Status in accordance with §63.9(h) within 60 days of completing the performance stack test;

- An annual compliance certification report is to be prepared by March 1 of each year for the previous year containing the information specified in §63.11225(b)(1) through (4). The report is to be submitted by March 15 if the source experiences any deviations from the applicable requirements during the reporting period.

Records are to be maintained as specified in §63.11225(c)(1) through (5).

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units (EGU) [40 CFR 63 Subpart UUUUU]

EPA has signed the final rule for coal and oil fired utility steam generating units on December 16, 2011.

The affected source under this MACT is coal-fired EGU or an oil-fired EGU as defined in §63.10042.

> Coal fired EGU means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.
>
> Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

As included in the application, the combined electric power output capacity of two boilers at the Lumberton Energy facility is 35 MW. Thus, each EGU at the facility is NOT capable of combusting more than 25 MW of fossil fuels. Thus, the coal-fired boilers are NOT subject to the above MACT standard.

4.2.10 15A NCAC 2D .2400 - Clean Air Interstate Rules

The existing fossil fuel (coal/natural gas/No and No. 4 fuel oil)-fired boilers are subject to the Clean Air Interstate Rules. But, they are not subject to this program when burning non-fossil-fuels such as wood.

4.2.11 15A NCAC 2Q .0400 - Acid Rain Procedures

The existing fossil fuel (coal/natural gas/No and No. 4 fuel oil)-fired boilers are subject to the Acid Rain program requirements. But, they are not subject to this program when burning non-fossil-fuels such as wood.

4.2.12 15A NCAC 2Q .0317 - Avoidance Condition for MACT

The Permittee has requested to take an enforceable permit condition to limit the emissions of HAPs on a facility wide basis to less than 10 tons/yr (single) and 25 tons/yr (aggregate).

As included in the permit application, the potential to emit for the single largest HAP (hydrogen chloride) is approximately 9.8 tons/yr, while the aggregate HAP potential emissions are approximately 23.5 tons/yr, both when burning wood.

The revised permit will include appropriate monitoring including record keeping and reporting requirements, to assure compliance with the above MACT avoidance stipulation.

4.2.13 Senate Bill 3 (Session Law 2007-397)

This law requires that a biomass combustion process at a new renewable energy facility that delivers power to the electric power supplier and that is otherwise not subject to PSD program's Best Available Control Technology (BACT) requirements, shall meet the (Senate Bill 3) BACT. This BACT requirement is commonly called SB3 BACT. The DAQ shall determine the SB3

BACT on a case-by-case basis and shall take into account cumulative and secondary impacts associated with the concentration of biomass facilities in close proximity to one another.

A discussion of the SB3 BACT determination for PM/PM_{10}/$PM_{2.5}$, SO_2, NOx, VOC, and Hg emissions for the proposed project can be found in Section 7 of this document.

SECTION 5.0
BEST AVAILABLE CONTROL TECHNOLOGY

5.1 BACT

Each pollutant subject to PSD review must employ BACT as described in Section 4.1 above. Given the variation between emission sources, facility configuration, local airsheds, and other case-by case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economics, energy, and environmental impact are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impossible, BACT can be defined by the use of a particular type of control device and its achievable emission reduction efficiency. In no event can a technology be recommended which would not comply with any applicable standard of performance under 40 CFR Parts 60 and 61.

To assist in bringing consistency to the BACT process, the EPA has issued guidance encouraging all PSD applicants to use the "top-down" approach to BACT. NCDAQ does not strictly adhere to EPA's top-down guidance. Rather DAQ implements BACT in strict accordance with the statutory and regulatory language. As such, DAQ's BACT conclusions may differ from those of the applicant or EPA.

In general, the top-down approach consists of five basic steps. These are:

1) Identify all control technologies,
2) Eliminate technically infeasible options,
3) Rank remaining control technologies by control efficiencies,
4) Evaluate the most effective controls and document results, and
5) Select BACT

The first step in this approach is a comprehensive listing of control technologies for each applicable pollutant. Step two is a demonstration of technical feasibility to ensure the technology evaluated was appropriate for the characteristic gas stream to be treated. Step three ranks the remaining control technologies by control effectiveness, including the control efficiencies (percent of pollutant removed), expected emission rate (tons per year), expected emission reduction (tons per year), economic impacts (total cost effectiveness, incremental cost effectiveness), environmental impacts (including emissions of toxic or hazardous air contaminants), and energy impacts (benefits or disadvantages). Step four is a case-by-case evaluation of energy, environmental, and economic impacts. Step five requires the selection of the most effective option not rejected as BACT for the emission source.

The BACT analysis will focus on applicable control techniques for emissions of CO and sulfuric acid mist, when burning wood in two, existing, stoker boilers, each 215 million Btu/hr.

5.2 Previous BACT/LAER Determinations[4]

DAQ has researched the RACT/BACT/LAER Clearinghouse information for the time period from 2005 to present, to identify and evaluate the current BACT determinations for emissions of CO and sulfuric acid mist, from wood-fired boilers (100 million Btu/hr to 250 million Btu/hr). The following is a summary of this search:

CO

There are four BACT determinations for wood-fired boilers in the size range as indicated above. These determinations include emission limits between 0.29 lb/million Btu and 0.6 lb/million Btu, using good combustion control (one determination also includes high pressure overfire air as control).

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[4] Note that prior BACT/LAER determinations are useful for identifying candidate control technologies but are not relied upon to establish presumptive BACT limits. There is limited information available to allow NCDAQ to make meaningful conclusions regarding the actual performance of the sources in the database. Moreover, BACT requires consideration of air quality which is unique to each site.

Sulfuric Acid Mist

There is not any BACT determination for wood-fired boilers in the size range as indicated above.

The RBLC data has been summarized in Appendix D.

5.3 BACT Analysis for CO Emissions from Wood-fired Boilers

As stated in Section 4.1 Table above, the potential uncontrolled CO emissions from the existing wood-fired boiler (215 million Btu/hr), based upon the historical emission factor of 0.2 lb/million Btu, is 188.3 tons/yr.

CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Factors affecting CO emissions include firing temperatures, excess oxygen and residence time in the combustion zone, and combustion zone mixing characteristics. An increase in the combustion zone residence time and oxygen levels and mixing of fuel and combustion air will increase oxidation rates and decrease CO emission rates. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers typically emit more CO than larger boilers. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger units.

In general, emissions of NO_x and CO are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO emissions and vice-versa). Accordingly, boiler combustion controls designed to lower NO_x emissions (e.g., lower combustion temperatures) can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed. Accordingly, boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO.

The Permittee has identified the following control technologies potentially applicable to the wood-fired boilers:

- Catalytic oxidation
- "Hot-side" catalytic oxidation
- Thermal oxidation
- Good combustion controls

Catalytic Oxidation

Catalytic oxidation is a post combustion control that oxidizes CO to CO_2 in the presence of a catalyst (typically a precious metal that is usually deposited onto a solid honeycomb substrate). An acceptable flue gas temperature range for catalyst operation is 450°F–1,100°F. The oxidation process takes place spontaneously, without the requirement of introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion products to CO_2. Catalytic oxidation has been used primarily to control CO and VOC on combustion turbines firing natural gas.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorus and silica will act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also subject to masking and/or blinding by fly ash contained in the exhaust gas stream of a biomass-fired boiler. Because of the potential for oxidation catalyst fouling and/or deactivation on the biomass-fired boilers, the catalyst units must be located downstream of the particulate control device (fabric filter). Therefore, a supplemental burner is necessary to reheat the flue gas to the requisite temperature.

“Hot-side” Catalytic Oxidation

“Hot-side” catalytic oxidation utilizes the same oxidation process as described above but does not require a supplemental burner since the process is located upstream of the air heater within the acceptable flue gas temperature range for catalyst operation. However, the “hot-side” catalytic oxidation system must be used in conjunction with a hot-side ESP as the pre-treatment device, due to the operating temperature constraints. Without a particulate pretreatment device, the particulate-laden flue gas stream would foul the catalyst. Even with the hot-side ESP as the pretreatment device, the catalyst is still susceptible to blinding and/or poisoning by the fine particulates in the flue gas exiting the hot-side ESP.

Thermal Oxidation

Thermal oxidation oxidizes CO to CO_2 through a separate combustion process. The process destroys CO by passing the gas stream though a high temperature region. It consists of a combustion chamber, a burner, and a heat exchanger/shell that preheats the incoming air. Thermal oxidizers are usually operated at 1,500°F–1,800°F to achieve an 85% reduction in CO.

The thermal oxidizer components are subject to fouling by PM. Accordingly, for biomass-fired boilers, the thermal oxidizer would need to be located downstream of the boiler’s PM control device. In addition, a thermal oxidizer requires a source of supplemental fuel, typically natural gas, to raise the exhaust stream to the required oxidation temperature.

Good Combustion Practices

Good combustion practices are based upon proper boiler design and proper operation of the boiler. Good combustion practices mean operation of the boiler at high combustion efficiency, thereby reducing products of incomplete combustion. Good combustion practices include operation at sufficiently high combustion temperatures, adequate residence time, adequate excess air and adequate turbulence, which ensures good mixing and availability of O_2 for efficient combustion. Reducing emissions of CO can be accomplished by increasing the air available for combustion and/or the combustion temperature. However, these measures will increase NO_X emissions.

The Permittee has provided the following discussion with respect to technical infeasibility for the options discussed above:

Thermal oxidation has primarily been applied on industrial exhaust streams to reduce VOC and hazardous air pollutant (HAP) emissions. The conversion of CO into CO_2 is a by-product of the process. Thermal oxidation is applicable only to gas streams with high levels of CO, VOCs and HAPs, such as chemical processing facilities, and not the lower CO concentrations exiting in a well-designed and operated wood-fired boiler. Therefore, this control technique is considered technically infeasible because the wood-fired boilers of Lumberton Energy are essentially thermal oxidizers and their CO emission rate would not be expected to improve from an add-on thermal oxidation process.

Therefore, catalytic oxidation and good combustion practices are the only demonstrated and technically feasible control measures for CO reduction for the wood-fired boilers at this facility.

"Hot-side" catalytic oxidation has been proposed as BACT for the proposed Peregrine Energy Corporation (Peregrine) facility in Hartsville, South Carolina. The SC agency is processing the air permit application for the above facility, so the technology has not yet been demonstrated on an actual operation of any wood-fired boiler. However, the Permittee has prepared an economic impact analysis for the "hot-side" catalytic oxidation technology.

Thus, the Permittee has ranked the following feasible technologies with respect to their control efficiencies for emissions of CO from wood-fired boiler:

CONTROL TECHNOLOGY	CONTROL EFFICIENCY RANGE (%)
Catalytic oxidation	50-90
"Hot-side" catalytic oxidation	50-90
Combustion controls	25-50

Evaluation of Controls based on Energy, Environmental and Economic Impacts

The Permittee has provided the evaluation of the above most feasible control (control option with the highest efficiency of removal for CO) based upon the statutory factors of energy, environmental and economic.

The energy impacts associated with the installation and operation of catalytic oxidation or "hot-side" oxidation is considered to be reasonable.

Economic Impact

Catalytic Oxidation

Retrofit installation of a catalytic oxidation system may require removal or relocation of existing equipment, increasing the costs over catalytic oxidation installation on a new boiler.

A cost evaluation of catalytic oxidation has been performed with the supplemental burner fired with natural gas, No. 2 distillate fuel oil, and No. 6 residual fuel oil. The average cost effectiveness for catalytic oxidation is approximately $10,467 to $13,490 per ton of CO removed, depending upon the type of fuel used to fire the supplemental burner and the assumption of a minimum control efficiency of 50%. While the applicant believes that the cost is extremely high, the requirement of BACT prohibits the rejection of technology on a single factor and require a comprehensive evaluation of technology consistent with the definition of BACT.

"Hot-side" Catalytic Oxidation

The retrofit installation of a "hot-side" catalytic oxidation system to the existing boilers would require extensive removal or relocation of existing equipment, including the demolition of the existing economizer and replacement with a new economizer, wall and roof penetrations to accommodate the new equipment, and fabrication and installation of new duct work and insulation. The extensive construction required for the retrofit installation increases the costs as compared to the "hot-side" catalytic oxidation installation on a new boiler such as the proposed Peregrine facility (SC). Also, because of the temperature requirements of the flue gas and the need to have a clean flue gas stream due to poisoning/fouling issues with the catalyst, a hot-side ESP would be required to be installed prior to the "hot-side" oxidation catalyst. The additional cost of retrofit installation of a hot-side ESP (over the existing baghouse) was included in the cost of installing a "hot-side" oxidation catalyst. The equipment cost (new ESP) and additional cost of operating the hot-side ESP was not available for this BACT analysis and therefore was not included in the cost effectiveness evaluation. In summary, the cost effectiveness provided below is a conservative estimate for this control option.

The average cost effectiveness for catalytic oxidation is approximately $14,170 per ton of CO removed with the assumption of a minimum control efficiency of 50%. While the applicant believes that the cost is extremely high, the requirement of BACT prohibits the rejection of technology on a single factor and require a comprehensive evaluation of technology consistent with the definition of BACT.

Thus, the only remaining control option is "good combustion control". The Permittee emphasizes that it currently implements good combustion practices when burning coal and it will continue to use these practices when burning wood, in minimizing CO emissions from the boilers. Utilizing good combustion practices, these boilers can achieve a CO emission rate of 0.20 lbs/million Btu on a 30-day rolling average from the wood-fired boilers averaged on an annual basis. The Permittee adds that this control technology is consistent with the technology implemented on other recent permit actions for wood-fired boilers identified during this evaluation. Additionally, as per the Permittee, the above CO emission limit for the wood-fired boilers is less than that for similarly sized wood-fired boilers identified in the RBLC database. Specifically, the Permittee provided RBLC query shows CO emission rate ranging from 0.10 to 0.93 lb/million Btu (size < 500 million Btu/hr). The Permittee argues that the 0.10 lb/million Btu CO emission limit is for the Biomass Energy, LLC - South Point Power facility (318 million Btu/hr wood fired boiler, RBLC ID OH-0307) which has never been operated. Therefore, the Permittee has concluded that the above emission rate has not been demonstrated as achievable on a similarly-sized wood fired boiler. Excluding the above determination, the lowest CO emission rate identified in the RBLC query was 0.19 lb/million Btu (77 million Btu/hr wood fired boiler at International Biofuels Inc, RBLC ID VA-0298). Thus, the Permittee has proposed a BACT of 0.2 lb/million Btu on a 3-run average (stack test), using good combustion control.

DAQ Proposed BACT

It is DAQ's understanding that the CO limit of 0.2 lb/million Btu, proposed by the Permittee as BACT, is based on an effluent concentration of 222 ppm (dry) employing good combustion practices. Based on DAQ's prior work in developing 112j model permit for wood-fired boilers in NC, DAQ believes that it would be difficult for stoker boilers firing wood to achieve such low CO emissions. DAQ further believes that effluent concentrations in the range of 500 ppmd may be more appropriate for wood fired boilers at this facility. Using 500 ppmvd CO concentration and the maximum flue gas flow rate of 6,901 lb-mole/hr, one can estimate an emission limit of CO as 0.45 lb/million Btu.

Thus, DAQ proposes BACT limit for the wood fired boilers as 0.45 lb/million Btu using good combustion control practices. The compliance with the BACT emission limit will be determined on a 3-run average (stack test) basis.

5.4 BACT Analysis for Sulfuric Acid Mist Emissions from Wood-fired Boilers

As stated in Section 4.1 Table above, the potential uncontrolled sulfuric acid missions from the existing wood-fired boiler (215 million Btu/hr), based upon the historical emission factor of 0.011 lb/million Btu, are 10.4 tons/yr.

Small concentrations of H_2SO_4 will be emitted from the wood-fired boilers due to the sulfur content of the wood fuel. H_2SO_4 is formed by the further oxidation of SO_2 to sulfur trioxide (SO_3). SO_3 readily combines with water vapor (H_2O) available in the flue gas to form H_2SO_4. When flue gas containing H_2SO_4 vapor is cooled, sulfuric acid mist condenses to form a sub-micron aerosol mist.

The amount of H_2SO_4 formed is dependent upon the amount of SO_3 and water vapor present and the temperature of the flue gas. Consequently, the control of H_2SO_4 emissions will be in direct correlation with SO_2 removal.

The Permittee has identified the following control technologies potentially applicable to the wood-fired boilers:

- Dry Flue Gas Desulfurization (Dry FGD)
- Wet Flue Gas Desulfurization (Wet FGD)
- Inherently Low Sulfur Fuel

Air pollution controls involve reacting SO_2 with an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be initiated using either a dry or wet contact system as described below. The control of H_2SO_4 emissions will be in direct correlation with SO_2 removal.

Dry Flue Gas Desulfurization (FGD)

Dry FGD is an established technology, with removal efficiency typically in the range of 90 percent. Dry FGD control systems include spray dryer absorbers, circulating dry scrubbers and sorbent injection systems. In a spray dryer absorber control system, the combustion process exhaust stream passes through the sprayer dryer absorber upstream of a particulate matter control device. An alkaline slurry (typically lime) is injected in the spray dryer absorber using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream. If a fabric filter is used on the particulate control device, the alkaline reagent may further react with the SO_2 that passes through the filter cake.

Circulating dryer scrubber technology uses flue gas, ash, and lime sorbent to form a fluidized bed in an absorber vessel. Water is added to the circulating dry scrubber absorber vessel to enhance the lime and SO_2 absorption reactions. By-products leave the absorber in the dry form with the flue gas for subsequent removal by the downstream particulate control device.

A dry sorbent injection system pneumatically injects a powdered sorbent directly into the furnace, the economizer, or downstream ductwork. Dry sorbent systems typically use calcium or sodium based alkaline reagents. A dry sorbent injection system requires no slurry equipment or reactor vessel because the sorbent is stored and injected dry into the flue duct where it reacts with the SO_2. The sulfite/sulfate salt reaction products are then removed using particulate control equipment. Dry sorbent injection has achieved greater than 90% SO_2 control efficiencies.

Wet FGD

Wet FGD is a mature technology that is available from a number of suppliers. In a wet FGD system, the flue gas passes through a recirculating alkaline slurry that absorbs and neutralizes the SO_2. Most wet FGD systems use limestone or lime as the alkali source. The performance of a wet FGD system varies with individual unit design; however, removal efficiencies in the range of 95 percent are achievable. In the wet scrubbing process, the flue gas is contacted with an alkaline solution or slurry (typically lime or limestone) in an absorber. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by absorption and reaction with the alkaline medium. Resulting waste product is a slurry containing both reacted and unreacted alkaline materials. There are numerous design variations of wet scrubbers, with wet limestone systems being the most common process used. Generally, for lower sulfur fuel, it is more difficult to achieve the higher percent sulfur removal rates. The range of SO_2 reduction efficiency at wet scrubber installations is slightly higher than that for dry scrubbing.

Inherently Low Sulfur Fuel

Wood is an inherently low sulfur fuel. Because SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel, the combustion of low sulfur fuel produces lower SO_2 emissions.

The Permittee has provided the following discussion with respect to technical infeasibility for the above options:

Neither dry FGD nor wet FGD has been applied on wood-fired units sized similarly to those at Lumberton Energy based on the sources evaluated. The only facility utilizing dry FGD (spray dryer absorber or sorbent injection) identified is Biomass Energy, LLC – South Point Power (SPP). The SPP emission units were permitted but have never operated. Therefore, the application of dry FGD technology on wood-fired boilers sized similarly to those at Lumberton Energy has not been demonstrated. Because, there are no technical demonstrations of either dry FGD or wet FGD for wood-fired boilers sized similarly to those at this facility, the Permittee has concluded that these technologies are technically infeasible.

Thus, inherently low sulfur fuel is the only demonstrated and technically feasible control measure for H_2SO_4 reduction in biomass-fired boilers.

Therefore, the Permittee has proposed an emission limit of 0.011 lb/million Btu on a 3-hour rolling average for the boilers using inherently low sulfur fuel as BACT.

DAQ Proposed BACT

DAQ agrees with the Permittee that the current BACT for H_2SO_4 emissions from the proposed wood-fired boilers is the use of inherently low sulfur wood. Thus, it approves the use of inherently low sulfur wood as BACT with an emission of 0.011 lb/million Btu. The compliance with the BACT emission limit will be determined using a stack test as a 3-run average.

5.6 BACT Summary

The following Table presents a summary of DAQ proposed BACT for approval for emissions of CO and H_2SO_4 from wood-fired boilers:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS	CONTROL TECHNOLOGY
Boilers (ID Nos. ES-1A and ES-1B)	CO	0.45 lb/million Btu [stack test: 3-run average]	good combustion control
	H_2SO_4	0.011 lb/million Btu [stack test: 3-run average]	use of low sulfur wood

SECTION 6.0
AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The PSD modeling analysis described in this section was conducted in accordance with current PSD directives and modeling guidance. Numerous references are made to the draft October 1990 EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Non-attainment Area Permitting, which will herein be referred to as the NSR Workshop Manual.[5]

A summary of the modeling results is presented in the last topic, PSD Air Quality Modeling Result Summary. A detailed description of the modeling and methodology is described below.

6.2 Project Description / Significant Emission Rate (SER) Analysis

As stated in Section 1 above, Lumberton Energy operates a cogeneration power plant in Lumberton, North Carolina, which consists of two boilers, 215 million Btu/hr each, and a 35 MW steam turbine generator. Also, in the emissions mix is a firewater pump. Project emissions analysis was accomplished and the emission changes are shown below in Table 6.2-1.

Table 6.2-1 Project Emissions Analysis

Pollutant	Change in Emissions (tons/yr)	Significant Emission Rate (tons/yr)	PSD Review Required?
NO_x	-78.53	40	No
$PM_{2.5}$	4.7	10	No
PM_{10}	4.44	15	No
SO_2	-808.92	40	No
CO	345.73	100	Yes
H_2SO_4*	8.59	7	Yes
VOC**	29.42	40	No

[5] The NCDAQ refers only to those sections of the draft workshop manual to which the NCDAQ endorses. Any section which is not referenced is not relied upon and guidance and policy contained therein is not binding on approved states like NC (SIP-approved PSD program).

Pollutant	Change in Emissions (tons/yr)	Significant Emission Rate (tons/yr)	PSD Review Required?
GHG***	397,667 CO_{2e}	75,000 CO_{2e}	No

** No SIL or NAAQS exist; modeled by NC air toxics standards.*
*** Not evaluated separately. NC models it as a part of regional modeling.*
**** Deferred from PSD applicability as per temporary rule in 15A NCAC 2D .0544 effective December xx, 2011.*

6.3 Preliminary Impact Air Quality Modeling Analysis

An air quality preliminary impact analysis was conducted for the pollutants shown in Table 6.2-1 above that require PSD analysis and have Significant Impact Levels (SIL). The modeling results were then compared to the applicable SIL as defined in the NSR Workshop Manual to determine if a full impact air quality analysis would be required for that pollutant.

Lumberton Energy facility is located two miles south of Lumberton, North Carolina, in Robeson County. For modeling purposes, the area is classified “rural”, based on the land use type scheme established by Auer 1978.

The Permittee evaluated CO with AERMOD in five operational scenarios, and compared the High First-High (H1H) results of all scenarios to the SIL. The five scenarios were: one boiler running at 50, 75, and 100 percent, and two boilers running at 75 and 100 percent. Emissions were emitted from two stacks in the modeling, the boiler stack and the fire water pump stack. Appropriately spaced receptors, beginning at the fenceline, were used to determine all impacts. Additionally, Lumberton Energy used normal regulatory defaults and five years of NCDAQ-processed meteorology in the modeling. Specifically, the meteorological data used was NCDAQ's Raleigh dataset for PSD use. Following NCDAQ guidance, the Permittee ran AERSURFACE for the facility location to determine which of the three Raleigh PSD datasets was most appropriate for this application. Based on the surface roughness results from the AERSURFACE run, Lumberton Energy used the medium (sfc roughness) Raleigh dataset. NCDAQ believes this meteorological dataset is representative of the facility site.

As the modeling results in Table 6.3-1 show, CO impacts modeled below its SIL and thus require no further CLASS II modeling. The maxima in all five operational scenarios were identical and were controlled by the low-level fire water pump source. The location of the maxima was on the property line directly beside the fire water pump.

Table 6.3-1 Class II Significant Impact Results (ug/m^3)

Pollutant	Averaging Period	Facility maximum Impact	Class II Significant Impact
CO	8-hour	192	500
	1-hour	361	2000

6.4 Class II Full Impact Air Quality Modeling Analysis

A Class II Area NAAQS and PSD increment analysis were not required because CO emissions modeled demonstrated impact below its SIL.

6.5 Non Regulated Pollutant Impact Analysis (North Carolina Toxics)

Lumberton Energy modeled 18 toxic pollutants using AERMOD in the same manner as in the SIL analysis, except that only the two boilers, 100 percent load, scenario was evaluated since that scenario had the highest emission rates. Five of the air toxics (acrolein, formaldehyde, chromium VI, benzene, and benzo(a)pyrene) were evaluated from a combination of the boiler stack and the fire water pump stack. The remaining toxic pollutants were assumed to be emitted entirely from the boiler stack. All the modeled pollutants demonstrated compliance on a source-by-source (where there were two stacks modeled) basis with the applicable NC Acceptable Ambient Levels (AAL). The maximum concentrations as shown in Table 6.5-1 occurred along or near the facility fence line.

Table 6.5-1 Toxics Modeling Results

Pollutant	Averaging Period	Max Impact (ug/m^3)	AAL (ug/m^3)	% AAL
Acrolein	1 hr	0.015	80	<1
Ammonia	1 hr	2.6	2,700	<1
Arsenic	annual	9.6E-5	2.3E-4	42
Benzene	annual	0.00248	0.12	2
Benzo(a)pyrene	annual	0.00001	0.033	<1
Beryllium	annual	4.8E-6	4.1E-3	<1
Cadmium	annual	1.8E-5	5.5E-3	<1
Chlorine	1 hr	1.8E-4	900	<1
Chlorine	24 hr	8.7E-2	37.5	<1
Soluble Chromate Compounds, as Chromium (VI) Equivalent	24 hr	2.04E-3	0.62	<1
Formaldehyde	1 hr	0.117	150	<1
Sulfuric Acid	1 hr	3.2	100	3
Sulfuric Acid	24 hr	1.6	12	13
Hydrogen Chloride	1 hr	7.6E-1	700	<1
Hexachlorodibenzo-p-dioxin	annual	7.0E-6	7.6E-5	9
Manganese	24 hr	1.5E-2	31	<1
Mercury	24 hr	1.8E-3	0.6	<1
Nickel	24 hr	1.6E-3	6	<1
Tetrachlorodibenzo-p-dioxin	annual	2.1E-9	3E-6	<1
Vinyl Chloride	annual	7.9E-5	0.38	<1

6.6 Additional Impact Analysis

Additional impact analyses were conducted for growth, soils and vegetation, and visibility impairment.

6.6.1 Growth, Soils and Vegetation Impacts

Lumberton Energy stated that about 25 jobs will be created from this project. Since they hope to fill most of those jobs from the existing labor force, they do not anticipate that this project's growth impacts will be significant.

The Permittee compared CO impacts from this project to EPA's guidelines on soil and vegetation impacts. The facility impacts were far smaller than the listed thresholds. In addition, the Permittee noted that their project's ambient air impacts were well below the CO SIL and thus represented no danger of exceeding the CO primary NAAQS. NCDAQ agrees that this measure is a conservative test for impacts to soil and vegetation.

6.6.2 Class II Visibility Impairment Analysis

The Class II visibility impairment analysis submitted did not evaluate impacts beginning at the facility fenceline; however, since there are no NC designated sites of special visibility protection in the potential impact area and considering the relatively small emission rates for the pertinent pollutants; NCDAQ did not require any additional CLASS II visibility impairment analysis.

6.7 Class I Area - Additional Requirements

The closest Class I area to the facility is the Cape Romain National Wildlife Refuge which is about 170 km to the southeast. The Federal Land Manager (FLM) contact indicated that no CLASS I analyses would be required; subsequently, no CLASS I SIL or increment analysis was conducted.

6.8 PSD Air Quality Modeling Results Summary

Based on the PSD air quality ambient impact analysis, the proposed Lumberton Energy project will not cause or contribute to any violation of the NAAQS, PSD increments (Class I and Class II Increments), or any FLM AQRVs. A summary of the modeling results is presented below.

TABLE 6.8-1 – Lumberton Energy PSD Modeling Results							
SER Evaluation							
Pollutant	Annual E/R (Tons)	SER (Tons/yr)	SER Exceeded				

NO_x	-78.53	40	No
$PM_{2.5}$	4.7	10	No
PM_{10}	4.44	15	No
SO_2	-808.92	40	No
CO	345.73	100	Yes
H_2SO_4	8.59	7	Yes
VOC	29.42	40	No
GHG	397,667 CO_{2e}	75,000 CO_{2e}	Yes

Class II Area SIL Analysis

Pollutant	**Averaging Period**	**Maximum Impact (ug/m^3)**	**SIL (ug/m^3)**	**SIL Exceeded**
CO	1-hour	361	2000	N
	8-hour	192	500	N

Class II NAAQS Analysis

Pollutant	**Averaging Period**	**Maximum Onsite & Offsite Source Impacts (ug/m^3)**	**Back Ground Conc. (ug/m^3)**	**Total Impact (ug/m^3)**	**NAAQS (ug/m^3)**	**% NAAQS**
SO_2	Annual	29.1	8	37.1	80	46.4
	24-hour	313	34	347	365	95
	3-hour	966.9	149	1115.9	1300	89
NO_x	Annual	27.3	16	43.3	100	43.3
PM_{10}	Annual	21	23	44	50	88
	24-hour	54.1	39	93.1	150	62
$PM_{2.5}$	Annual	2.7	12	14.7	15	98
	24-hour	8	26	34	35	97
TSP	Annual	12.8	n/a	12.8	75	17.1
	24-hour	66.7	n/a	66.7	150	44.6

Class II PSD Increment Analysis

Pollutant	**Averaging Period**	**Maximum Onsite & Offsite Source Impacts (ug/m^3)**	**Back Ground Conc. (ug/m^3)**	**Total Impact (ug/m^3)**	**PSD Increment (ug/m^3)**	**% PSD**

N/A						

NC Toxic Pollutants					
Pollutant	**Averaging Period**	**Maximum Impact (ug/m^3)**	**AAL (ug/m^3)**	**% AAL**	
Acrolein	1 hr	0.015	80	<1	
Ammonia	1 hr	2.6	2,700	<1	
Arsenic	annual	9.6E-5	2.3E-4	42	
Benzene	annual	0.00248	0.12	2	
Benzo(a)pyrene	annual	0.00001	0.033	<1	
Beryllium	annual	4.8E-6	4.1E-3	<1	
Cadmium	annual	1.8E-5	5.5E-3	<1	
Chlorine	1 hr	1.8E-4	900	<1	
	24 hr	8.7E-2	37.5	<1	
Soluble Chromate Compounds, as Chromium (VI) Equivalent	24 hr	2.04E-3	0.62	<1	
Formaldehyde	1 hr	0.117	150	<1	
Sulfuric Acid	1 hr	3.2	100	3	
	24 hr	1.6	12	13	
Hydrogen Chloride	1 hr	7.6E-1	700	<1	
Hexachlorodibenzo-p-dioxin	annual	7.0E-6	7.6E-5	9	
Manganese	24 hr	1.5E-2	31	<1	
Mercury	24 hr	1.8E-3	0.6	<1	
Nickel	24 hr	1.6E-3	6	<1	
Tetrachlorodibenzo-p-dioxin	annual	2.1E-9	3E-6	<1	
Vinyl Chloride	annual	7.9E-5	0.38	<1	

SECTION 7.0
SENATE BILL 3 (Session Law 2007-397)
BEST AVAILABLE CONTROL TECHNOLOGY

7.1 SB3 BACT

As stated in Section 4.13 above, Senate Bill 3 (SB3) requires that a biomass combustion process at a "new renewable energy facility" that delivers power to the electric power supplier and that is otherwise not subject to PSD program's Best Available Control Technology (BACT) requirements, shall meet the (Senate Bill 3) BACT. This BACT requirement is commonly known as SB3 BACT.

"New renewable energy facility" is defined as a renewable energy facility that either (a) was placed into service on or after January 1, 2007, (b) delivers or has delivered electric power to an electric power supplier pursuant to a contract with NC GreenPower Corporation that was entered into prior to January 1, 2007, (c) is a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier.

At the time of submitting this application, the Permittee has not submitted an application to register the facility as "new renewable energy facility" with the North Carolina Utilities Commission. The Permittee has, thus, elected to obtain an approval for SB3 BACT for various pollutants at this time, although it is not required to do so at this time.

As included in Table 4-1 above, the emissions increases for PM, PM10, PM2.5, and VOC do not exceed the respective significance thresholds under PSD and hence, for these pollutants, SB3 BACT analysis is required for this project. It should also be stated here that in addition to the above pollutants, the Permittee has submitted SB3 BACT analysis for the emissions of CO, H_2SO_4, GHG, SO_2, and NOx.

As detailed in Section 5 above, the proposed wood burning in the existing boilers has been reviewed for PSD BACT for CO and H_2SO_4. Hence, for emissions of CO and H_2SO_4, the SB3

BACT is not required. For GHG, as stated in Section 1 above, DAQ has deferred the applicability of PSD BACT as per the temporary rule at 15A NCAC 2D .0544 effective December xx, 2011. For PM, DAQ proposes that the requirements of PM_{10}/$PM_{2.5}$ under SB3 BACT would be sufficient to meet the SB23 BACT requirement for PM emissions from this project.

As also indicated in Table 4-1, there is a decrease in emissions of SO_2 and NOx emissions due to wood burning. Hence, the PSD BACT is not required for SO_2 and NOx. But, as per the requirements of this Session Law, SB3 BACT is required for these pollutants.

Finally, the Permittee has submitted SB3 BACT analysis for mercury emissions due to wood burning in these boilers as per the DAQ Memorandum "Senate Bill 3 Implementation Issues", August 27, 2010.

As per this law, the DAQ shall determine the SB3 BACT on a case-by-case basis and shall take into account cumulative and secondary impacts associated with the concentration of biomass facilities in close proximity to one another.

The Permittee has used the EPA's "top-down" approach to prepare BACT analysis under SB3. As noted above in the PSD BACT discussion, the use of "top-down" as described in the 1990 NSR Workshop manual in an approach that is inconsistent with the CAA. NCDAQ does require applications to evaluate candidate technologies including "top" technologies then evaluates those candidate technologies consistent with the law.

7.2 Previous (PSD) BACT/LAER Determinations

DAQ has researched the RACT/BACT/LAER Clearinghouse information for the time period from 2005 to present, to identify and evaluate the current BACT determinations for emissions of PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC, and mercury, from the wood-fired boilers (100 million Btu/hr to

250 million Btu/hr).[6] The following is a summary of this search:

PM-10/PM2.5

All of these determinations include emission limits for PM10 emissions, ranging between 0.025 lb/million Btu to 0.1 lb/million Btu (filterable only) using ESP, wet scrubber or multiclone or combination of one or more of these control equipment.

SO_2

There are not any determinations in this database for the desired size range (100-250 million Btu/hr) for wood-fired boilers.

NOx

There are a few BACT determinations, including emission limits of 0.15 lb/million Btu to 0.22 lb/million Btu, using good combustion control or selective non-catalytic reduction. There is one determination, which includes an emission limit of 0.81 lb/million Btu with no control required.

VOC

There is only one BACT determination in the desired size range (100-250 million Btu/hr) for wood-fired boilers, which includes an emission limit of 0.017 lb/million Btu using over-fire air and good combustion control.

Mercury

There are not any determinations in this database for the desired size range (100-250 million

[6] As noted in the PSD BACT section, the use of the clearinghouse is limited to identifying candidate technologies. Permitted emission rates from the clearinghouse are, in almost all cases, not useful because the clearinghouse does not provide sufficient information regarding how the permitting authority considered the BACT statutory factors.

Btu/hr) for wood-fired boilers.

The RBLC search summary has been included in Appendix D.

7.3 BACT Analysis for PM/PM-10/PM2.5 Emissions from Wood-fired Boilers

PM is the general term for a mixture of solid particles and liquid droplets present in the emissions stream regardless of particle size. Generally PM_{10} and $PM_{2.5}$ emissions or fine particulates are a subset of PM emissions or coarse particulates and there are no control strategies specific to PM_{10} and $PM_{2.5}$. The control strategies implemented to minimize PM emissions are also considered effective at minimizing emissions of PM_{10} and $PM_{2.5}$. Therefore the SB3 State BACT analysis provided in the following paragraphs applies to PM_{10} and $PM_{2.5}$ emissions. PM is emitted from wood-fired boilers as a result of the ash and other inorganic and organic constituents contained in the fuel. Ash is the inorganic matter that does not participate in the combustion reactions. The composition of wood residue and the characteristics of the resulting emissions depend largely on the origin of the wood fuel.

Potentially applicable PM/PM_{10}/$PM_{2.5}$ control technologies are:

- Particulate wet scrubbers
- Electrostatic precipitators
- Mechanical collectors
- Fabric filters

Particulate Wet Scrubbers

There are a number of different types of particulate wet scrubbers. All particulate wet scrubber designs utilize particle and/or droplet inertia as the fundamental force to transfer particles from the gas stream to the liquid stream. Within the scrubber, particle-laden air is forced to contact the liquid droplets, sheets of liquid on a packing material, or jets of liquid from a plate. Particles with too much inertia impact on the water droplet, water sheet, or water jet instead of passing around the "target" with the gas stream. Particulate wet scrubber types include venturi scrubbers, impingement plate scrubbers, and spray towers.

Electrostatic Precipitators (ESPs)

ESPs remove particulate matter from a flue gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping.

Mechanical Collectors

Mechanical collectors use the inertia of the particles for collection. The particulate-laden gas stream is forced to spin in a cyclonic manner. The mass of the particles causes them to move toward the outside of the vortex. As the flue gas move down it then reverses direction moving up and out through the middle of the collector. Most of the large-diameter particles enter a hopper below the cyclonic tubes while the gas stream turns and exits the tube. Mechanical collectors are used whenever the particle size distributions generated by the process are relatively large (greater than 5 micrometers) and/or the control efficiency requirements are in the range of 25 to 85%. They are also used as the pre-collector of large-diameter embers generated in some combustion systems. Removal of the embers is necessary to protect high-efficiency particulate control systems downstream from the mechanical collectors.

Fabric Filters

A fabric filtration device (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through a layer of particulate and filter bags. The collected particulate forms a cake on the bag, which enhances the bag's filtering efficiency.

Fabric filters, ESPs, mechanical collectors and particulate wet scrubbers are considered technically feasible for $PM_{10}/PM_{2.5}$ control technologies for wood-fired spreader stoker boilers. The following Table provides a summary of the control efficiency ranges for all of these technically feasible options:

CONTROL TECHNOLOGY	CONTROL EFFICIENCY RANGE (%)
Fabric Filters	90-99
ESPs	90-99
Mechanical collectors	25-85
Particulate wet scrubbers	25-65

The ranking of each technically feasible $PM_{10}/PM_{2.5}$ control technology for wood-fired boilers is discussed more fully below:

- Fabric filters have typical design efficiencies between 90 and 99%. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. The installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash reduces this hazard.

- ESPs are the most common technology in the recent determinations included in the RBLC database. Collection efficiencies of 90 to 99 percent for PM have been observed for ESPs operating on wood-fired boilers.

- The most widely used particulate wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 65 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

- Mechanical collectors alone have low PM reduction. Often, two multi-cyclones are used in series, allowing the first collector to remove the bulk of the dust and the second to remove smaller particles. The efficiency of this arrangement varies from 25 to 85 percent depending on the particle size, with higher efficiencies achievable for larger particles.

Particulate wet scrubbers are simple in design and relatively low maintenance. However, one of the main disadvantages of particulate wet scrubbers is that they require make-up water to replace the water vaporized into the gas stream and lost to purge liquid and sludge removed from the scrubber system. Wet scrubbers also generate a waste stream in the form of a slurry or a wet sludge that must be treated properly. Disposal of the waste sludge is an added cost.

Wood-fired stoker boilers often use ESPs due to concerns over unburned carbon carryover, and the potential fire hazard that can result (i.e., hot carryover particles igniting the bags).

In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured as cylindrical bags. Bags are generally 6 to 9 m (20 to 30 feet) in length and 13 to 31 cm (5 inches to 1 foot) in diameter. Groups of bags can be placed in isolated compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Periodically, the cake is removed from the bags through physical mechanisms (e.g., a blast of compressed air from the "clean" side of the bag, reverse air, shaking bags etc.), which causes the cake to fall. The particulate is then collected in a hopper and periodically removed by the ash-handling system. Unlike ESPs, fabric filter capture of particulate matter is not based on the chemical and electrical or properties of the fly ash. The advantages of fabric filters include:

- High collection efficiency for a broad range of particle sizes;
- Flexibility in design (various methods of cleaning and filter media);
- Wide range of volumetric capacities; and
- Capable of removing a wide range of solid materials with varying characteristics.

Some disadvantages of fabric filters are as follows:

- For ash containing oily residues or high concentrations of carbon, catastrophic bag damage may occur due to fire;
- Pressure loss across the baghouse, and associated power requirements;
- Bag replacement requirements; and
- If the waste gases are at a temperature close to their dew point wet particles can cause blinding of the filter cloth.

A fabric filter also removes hazardous air pollutants (HAPs) that are in particulate form, such as most metals.

Fabric filters and ESPs have approximately equivalent removal efficiencies; however, ESPs are more sensitive to variations in gas stream conditions, such as flow rates, temperatures, particulate and gas composition, and particulate loadings. ESP particulate removal performance will, therefore, vary with the characteristics of the fuel. This is an important consideration given that characteristics of the wood fuel may vary widely. Fabric filters have better removal efficiencies of the smaller size or fines of the particulate matter (i.e. PM_{10}). In general, PM control technology effectiveness is expressed in terms of percent removal efficiency. It should be noted that the use of percent removal efficiency without specification of the gas stream conditions at the inlet to the control device is somewhat approximate because the percent removal efficiency may vary as a function of the particle size distribution, particle characteristics, particulate matter loading, and velocity. Furthermore, it should be noted that the collection efficiency of a PM control device is generally higher when there is a high particulate loading entering the device.

The operation of mechanical collectors alone does not result in high enough PM reduction to be an effective control measure.

The Permittee has proposed to utilize a combination of multi-cyclone and a fabric filter to achieve a $PM_{10}/PM_{2.5}$ emission rate of 0.011 lb/million Btu (filterable and condensable) as a 3-hr average.

As per the Permittee, the PM (PM less than 100 microns) emission rate, based upon the removal efficiency of the multicyclones and fabric filter, has been estimated to be 0.015 lb/million Btu.

The PM_{10} fraction is 74% of the total PM based on cumulative particle size distribution for wood-fired boilers (controlled by dry electrostatic granular filters), in accordance with Chapter 1.6 Wood Residue Combustion in Boilers, Table 1.6-5, AP-42, 9/03. Thus, the Permittee has proposed a BACT limit of 0.011 lb/million Btu (i.e., 0.015 lb/million Btu * 0.74 = 0.011 lb/million Btu).

For $PM_{2.5}$, the Permittee has based its BACT limit upon the stack test results of boilers when firing wood at Coastal Carolina Clean Power LLC, LLC (CCCP) facility. The spreader stoker boilers at the CCCP facility are the same make (Foster Wheeler) and size (215 million Btu/hr) as those at the Lumberton Energy facility, and are also controlled by fabric filters and multiclones. The proposed PM2.5 BACT limit is based upon the average of particulate matter (filterable and condesible) emissions rates of six (6) test runs conducted on Boilers 1A and 1B plus 1 standard deviation plus 10% for conservative margin of error. The 10% increase (for conservative margin of error) makes the PM2.5 BACT limit the same as the PM10 BACT limit.

Thus, the Permittee has concluded that the use of multi-cyclone and a fabric filter system to achieve a $PM_{10}/PM_{2.5}$ emission rate of 0.011 lb/million Btu (filterable and condensable) on a 3-hr average meets or exceeds SB3 State BACT determinations for similar wood-fired boilers.

DAQ Proposed BACT

DAQ believes that the Permittee may not be able to meet the emission limit of 0.011 lb/million Btu (both filterable and condensable) on a long-term basis for $PM_{10}/PM_{2.5}$. Based on the RBLC determinations as discussed above, DAQ proposes to approve a more appropriate emission limit for PM/PM_{10} of 0.036 lb/million Btu (both filterable and condensable) using multi-cyclone and fabric filter for PM/PM_{10} as BACT. DAQ also proposes a separate emission limit of 0.011 lb/million Btu (both filterable and condensable [both organic and inorganic including sulfuric acid mist]) as $PM_{2.5}$ BACT using the above controls. The compliance with these BACT emission limits will be determined using a stack test on a 3-run average basis.

7.4 BACT Analysis for SO_2 Emissions from Wood-fired Boilers

Emissions of sulfur oxides from spreader stoker boilers result from the oxidation of sulfur present in the fuel. Sulfur oxides formed during combustion are primarily SO_2 with minor amounts of sulfur trioxides (SO_3) and gaseous sulfates. These sulfur compounds form as the sulfur contained in the fuel is oxidized during the combustion process. Uncontrolled sulfur oxide emissions from biomass-fired boilers vary directly with the sulfur content. Due to the naturally occurring alkaline (i.e., calcium) content of the woody biomass fuel, a portion of the SO_2 will react within the combustion process to form calcium sulfate compounds.

Potentially applicable SO_2 control technologies are:

- Dry flue gas desulfurization (Dry FGD)
- Wet flue gas desulfurization (Wet FGD)
- Inherently low sulfur fuel

Dry Flue Gas Desulfurization (FGD)

Dry FGD is an established technology, with removal efficiency typically in the range of 90 percent. Dry FGD control systems include spray dryer absorbers, circulating dry scrubbers and sorbent injection systems. In a spray dryer absorber control system, the combustion process exhaust stream passes through the sprayer dryer absorber upstream of a particulate matter control device. An alkaline slurry (typically lime) is injected in the spray dryer absorber using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream. If a fabric filter is used on the particulate control device, the alkaline reagent may further react with the SO_2 that passes through the filter cake.

Circulating dryer scrubber technology uses flue gas, ash, and lime sorbent to form a fluidized bed in an absorber vessel. Water is added to the circulating dry scrubber absorber vessel to enhance the lime and SO_2 absorption reactions. By-products leave the absorber in the dry form with the flue gas for subsequent removal by the downstream particulate control device.

A dry sorbent injection system pneumatically injects a powdered sorbent directly into the furnace, the economizer, or downstream ductwork. Dry sorbent systems typically use calcium or sodium based alkaline reagents. A dry sorbent injection system requires no slurry equipment or reactor vessel because the sorbent is stored and injected dry into the flue duct where it reacts with the SO_2. The sulfite/sulfate salt reaction products are then removed using particulate control equipment. Dry sorbent injection has achieved greater than 90% SO_2 control efficiencies.

Wet FGD

Wet FGD is a mature technology that is available from a number of suppliers. In a wet FGD system, the flue gas passes through a recirculating alkaline slurry that absorbs and neutralizes the SO_2. Most wet FGD systems use limestone or lime as the alkali source. The performance of a wet FGD system varies with individual unit design; however, removal efficiencies in the range of 95 percent are achievable. In the wet scrubbing process, the flue gas is contacted with an alkaline solution or slurry (typically lime or limestone) in an absorber. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by absorption and reaction with the alkaline medium. Resulting waste product is a slurry containing both reacted and unreacted alkaline materials. There are numerous design variations of wet scrubbers, with wet limestone systems being the most common process used. Generally, for lower sulfur fuel, it is more difficult to achieve the higher percent sulfur removal rates. The range of SO_2 reduction efficiency at wet scrubber installations is slightly higher than that for dry scrubbing.

Inherently Low Sulfur Fuel

Wood is an inherently low sulfur fuel. Because SO_2 is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel, the combustion of low sulfur fuel produces lower SO_2 emissions.

As per the Permittee, neither dry FGD nor wet FGD has been applied on wood-fired units sized similarly to those at LENC based on the sources evaluated. The Permitete adds that the only facility utilizing dry FGD (spray dryer absorber or sorbent injection), identified in their RBLC evaluation, is Biomass Energy, LLC – South Point Power (SPP), and their emission units although permitted, have never been operated. Therefore, it has concluded that the application of dry FGD technology on wood-fired boilers sized similarly to the proposed wood-fired boilers at the Lumberton Energy has not been demonstrated and, thus, technically infeasible.

Thus, inherently low sulfur fuel is the only remaining, demonstrated and technically feasible control measure, for SO_2 reduction in the wood-fired boilers.

Thus, Lumberton Energy has proposed an emission limit of 0.140 lb/million Btu on a 30-day rolling average (using CEMS) based on the use of inherently low sulfur fuel as SO_2 BACT.

DAQ Proposed BACT

It is DAQ's understanding that the emission limit of 0.14 lb/million Btu, as proposed by the Permittee as BACT, is based on the sulfur content (0.06 percent weight) of the expected fuel mix (engineered wood, C&D wood and RR ties). But, as discussed in Section 4.2.5 above, the DAQ is not able to approve any specific wood types as requested in this permit application and, instead it will be approving burning of "non-CISWI subject wood" only in these boilers. It is expected that sulfur content of the "non-CISWI" subject wood would be much less than the above sulfur content.

In addition, the Permittee has assumed that almost all sulfur (95%) in wood gets converted into SO_2. But, DAQ believes that it is an inaccurate assumption. DAQ's research seems to indicate that very little sulfur is converted to SO_2 and significant sulfur remains or ties up as sulfates in the boiler ash. One research paper[7] indicates only 5% sulfur in wood is emitted as SO_2 and the rest ends up in the ash. The second research paper[8] indicates that less than 10% of total sulfur in bark is converted to SO_2 at the stack level and the remaining sulfur appears in the ash.

With the understanding that only "non-CISWI subject wood" will be approved, DAQ proposes to approve an emission limit of 0.025 lb/million Btu using low sulfur wood as SO_2 BACT. This DAQ proposed emission limit is based upon AP-42 data (Section 1.6 Wood Residue Combustion in Boilers), Hertford Renewable Energy BACT determination, and other RBLC determinations. Compliance with the BACT emission limit will be determined using CEMS on a 30-day rolling average basis.

7.5 BACT Analysis for NOx Emissions from Wood-fired Boilers

NO_X is the term used to collectively refer to nitrogen oxide (NO) and nitrogen dioxide (NO_2). NO_X emissions from combustion sources consist of two components: oxidation of atmospheric

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[7] K. L. Foster, R. C. Scherr, and R. E. Dickson, "Permitting a Wood-Burning Boiler in a Major Metropolitan Area", Journal of Air Pollution Control Association, August 1982.

[8] H. S. Oglesby and R. O. Blosser, "Information on the Sulfur Content of Bark and Its Contribution to SO_2 Emissions When Burned as a Fuel", Journal of Air Pollution Control Association, July 1980.

nitrogen contained in the combustion air (thermal NO_X and prompt NO_X) and conversion of chemically bound fuel nitrogen (fuel NO_X). Thermal NO_X results when atmospheric nitrogen is oxidized at the high temperatures occurring in the boiler firebox to yield NO, NO_2 and other oxides of nitrogen. Most thermal NO_X is formed in high-temperature areas where combustion air has mixed sufficiently with the fuel to produce a peak temperature. The rate of formation of thermal NO_X is a function of residence time and free oxygen and varies exponentially with peak flame temperature. Prompt NO_X forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_X formed. Fuel-related NO_X is formed from oxidation of chemically bound nitrogen present in the fuel. Most boiler NO_X emissions originate as NO. NO generated by the combustion process is subsequently further oxidized downstream of the combustion zone or in the atmosphere to the more stable NO_2 molecule.

Potentially applicable NO_X control technologies are:

- Selective catalytic reduction (SCR)
- Regenerative selective catalytic reduction (RSCR)
- Selective non-catalytic reduction (SNCR)
- Flue gas recirculation (FGR)
- Off- stoichiometric combustion.

Selective Catalytic Reduction (SCR)

The “hot-side” SCR is a post-combustion control technology that involves a catalyst bed installed between the boiler economizer and combustion air preheater and upstream of the particulate matter control device in a conventional power plant. The temperature range of the flue gas at this point is between 650°F and 750°F. Ammonia is injected into the flue gas stream, which catalytically reduces the NO_X to molecular nitrogen and water. Reductions of 70 to 90% can be achieved from this technology. A “hot-side” SCR is technically infeasible for biomass combustion because the flue gas is heavily laden with alkali/alkaline compounds causes rapid catalyst deactivation. The alkaline nature of wood ash has been known to deactivate the SCR catalyst by poisoning and fouling. Poisoning is the main cause of catalyst deactivation since alkaline salts, which embed into the pores of the catalyst, and sodium cause irreversible poisoning.

Regenerative Selective Catalytic Reduction (RSCR)

RSCR is another type of SCR capable of achieving a NO_X removal efficiency of greater than 80 percent. It is called regenerative SCR because it has a highly efficient direct heat transfer, which results in an overall heat recovery of greater than 95 percent. The "hot-side" SCR is a conventional SCR system that is located prior to the air heater and upstream of the PM control device where the flue gas exhaust stream is at the optimum temperature range of 600°F to 800°F as described in the previous paragraph. The "cold-side" SCR or RSCR, is located downstream of the PM control device. The flue gas temperature at this location is lower than the required temperature range for optimum catalytic reduction in the "hot-side" SCR system, so a natural gas or oil-fired duct burner is used to provide supplemental fuel to increase the flue gas temperature to the appropriate range. Prior to the flue gas entering the RSCR, ammonia is injected to ensure it is well mixed with the flue gas. Then the flue gas enters the RSCR and passes upward through a ceramic bed that has been heated by the duct burner. The hot ceramic bed increases the temperature of the flue gas to a maximum of 650°F prior to passing through the catalyst bed.

Selective Non-Catalytic Reduction (SNCR)

SNCR is the NO_x control measure commonly used for wood-fired boilers. SNCR is a post combustion control technology that involves ammonia or urea injection, but not in the presence of a catalyst. SNCR, like selective catalytic reduction (SCR), involves the reaction of NO_x with ammonia by which NO_x is converted to molecular nitrogen and oxygen. Without the use of a catalyst or supplemental hydrogen (H_2) injection, the NO_x reduction reaction temperature must be tightly controlled between 1,600° and 2,200°F (between 1,600° and 1,800°F for optimum efficiency). Below 1,600°F, ammonia will not fully react, resulting in unreacted ammonia that is emitted into the atmosphere (referred to as ammonia slip). If the temperature rises above 2,200°F, the ammonia added will be oxidized, resulting in an increased level of NO_x emissions.

Flue Gas Recirculation (FGR)

FGR technology is based on reducing thermal NO_X formation by introducing inert flue gas, which reduces oxygen concentration and absorbs heat, thereby reducing peak flame temperatures. FGR involves extracting a portion of the flue gas from the economizer or air heater outlet and reintroducing it to the furnace through a separate duct and a fan to the combustion air duct that feeds the windbox. The recirculated flue gas is mixed with the combustion air to reduce peak flame temperature, thereby suppressing NO_X formation. FGR is most effective for natural gas and low nitrogen-containing fuels because it reduces thermal NO_X.

Off-Stoichiometric Combustion (Over-Fire Air)

Off-stoichiometric combustion involves the mixing of the fuel and air in a way that reduces the peak gas temperatures and peak oxygen concentrations. Usually, a portion of the combustion flame is operated with very low oxygen levels (fuel rich) to allow a major portion of the fuel oxidation to occur under conditions where NO_x formation is suppressed. Combustion is completed in the remaining portion of the flame and/or combustion chamber by providing the remainder of the oxygen needed for complete fuel oxidation. There are a variety of different approaches for achieving off-stoichiometric firing conditions, including the use of over-fire air (OFA).

OFA refers to operating the lower burners as fuel rich and placing air injection nozzles above the burners to complete the combustion process. OFA reduces a portion of the combustion air in the burner zone and introduces it downstream through separate air ports to complete this combustion process. Over-fire air limits NOx emissions by two mechanisms:

- Suppressing thermal NOx formation by partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures; and
- Suppressing fuel NOx formation by lowering the concentration of air in the burner combustion zone where volatile fuel nitrogen is evolved.

SCR technology has been applied to natural gas-fired electrical utility boilers ranging in size from 250 to 8000 million Btu/hr and is widely used for large gas turbines. Installation of a conventional SCR is not an option on wood-fired units due to the high levels of catalyst poisons and particulates present in the ash of a typical wood fired boiler. The high content of soluble potassium or sodium in the wood fuels causes a rapid deactivation of the SCR catalyst. Because the potassium or sodium ion resembles the ammonium ion, the potassium or sodium ion may block access of the ammonium ion to active sites thus causing the deactivation. It should be noted that only one facility was identified in the RBLC query that utilized SCR technology. The facility, Biomass Energy, LLC – South Point Power (SPP), was permitted but has never operated. Therefore, the application of SCR technology on wood-fired boilers has not been demonstrated and is considered technically infeasible.

RSCR, SNCR, FGR and OFA are all technically feasible control options for NO_x. The following Table provides a summary of the control efficiency ranges for these technically feasible NO_x control technologies.

CONTROL TECHNOLOGY	CONTROL EFFICIENCY RANGE (%)
RSCR	50-90
SNCR	40-60
FGR	<20
OFA	30-50

The Permittee has provided below more in-depth discussion for ranking of these technically feasible NO_x control technologies:

1. RSCR is effective in controlling NO_x emissions from wood-fired boilers. RSCR is an air pollution control system that has been used in retrofitting boilers to comply with NOx emission standards to facilities generating Renewal Energy Certificates (RECs) in Massachusetts. In the US, RSCR has been installed at four (4) facilities (one in Maine, two in New Hampshire and one in Vermont). In these applications, RSCR was used for the purposes of qualifying the energy from these facilities for REC compliance. According to Babcock Power (an RSCR equipment vendor), the primary application of an RSCR system is to reduce NO_x emissions in the flue gas found at the tail end of the boiler where gas temperatures are relatively cool. Since this system only works at the "tail" end, but requires higher temperature gas, a system to re-heat the gas is necessary. The boiler gas is re-heated by burning fossil fuel (typically natural gas, propane or fuel oil) using duct burners. Once the exhaust is heated, ammonia is injected. The ammonia reacts with the NO_x via a catalyst to form nitrogen and water.

2. SNCR is the NO_x control measure most commonly used for wood-fired boilers. SNCR typically provides up to 60% NO_x reduction. SNCR systems have one well-documented environmental impact associated with them: ammonia emissions. There will be residual ammonia emissions from a SNCR system because not all of the ammonia injected will come in contact and react with the NO_x in the flue gas. SNCR efficiency is dependent on the ratio of ammonia to NO_x. Increasing the ammonia injection rate increases the control efficiency but also increases the amount of ammonia that is released to the atmosphere, known as ammonia slip. Ammonia emissions are a concern because ammonia compounds are contributors to regional haze and visibility degradation. Ammonia also is absorbed in the fly ash. Optimal operation of an SNCR system balances the ammonia injection rate with the NO_x controls and uses ammonia distribution, flue gas distribution and control of ammonia injection rate during load changes to ensure maximum NO_x control while limiting ammonia slip from the SNCR system.

3. Off-stoichiometric combustion includes over-fire air technology, which requires the introduction of combustion air to be separated into primary and secondary flow sections

to achieve complete burnout and to encourage the formation of nitrogen rather than NO_x. Primary air flow (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed. The secondary flow (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of over-fire air are critical to maintain efficient combustion. Application of OFA technology may achieve 30-50% NOx reduction.

4. In FGR technology 10-30% of the flue gas (at 350-400°C) is re-circulated and mixed with the combustion air. The resulting dilution in the flame decreases the temperature and availability of oxygen therefore reducing thermal NO_x formation. Flue gas recirculation for NO_x control is more attractive for new boilers than as a retrofit. Retrofit hardware modifications to implement FGR include new ductwork, a recirculation fan, devices to mix flue gas with combustion air, and associated controls. Flue gas recirculation alone achieves a relatively low level of NO_x reduction (<20%).

The energy impacts associated with the installation and operation of these control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as SB3 State BACT.

Economic Impact

The Lumberton Energy's wood-fired boilers are existing units and either RSCR or SNCR would require a retrofit installation. For RSCR retrofit installations on existing boilers, new ductwork is required to integrate the RSCR system with the existing equipment. The increase in cost when compared to installation on a new unit is primarily due to modifications to existing ductwork, the cost of structural steel and reactor construction, auxiliary equipment costs, such as additional fans, and engineering costs. In addition, significant demolition and relocation of equipment may be required to provide space for the reactor. These costs can account for over 30% of the capital costs associated with RSCR. For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied by boiler equipment such as watertubes. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment such as ductwork. Removal or relocation of this equipment increases the installation costs. Retrofit installation of the SNCR system generally calls for additional expenditures in the range of 10% to 30% of the SNCR system cost.

An RSCR system typically costs the most of the different types of SCR systems because of the additional equipment and operational costs required for flue gas reheating and heat recovery. The Permittee has provided a cost evaluation of RSCR with the supplemental burner fired on a) natural gas b) No. 2 distillate fuel oil, and c) No. 6 residual fuel oil. This cost evaluation (based on a control efficiency of 75%) indicates a cost effectiveness of approximately $10,607 to $12,937 per ton of NO_x removed, based upon the type of fuel used to fire the supplemental burner. The Permittee considers this cost as prohibitive and RSCR is therefore eliminated from further consideration in the SB3 State BACT evaluation. While the applicant believes that the cost is extremely high, the requirement of BACT prohibits the rejection of technology on a single factor and require a comprehensive evaluation of technology consistent with the definition of BACT.

Lumberton Energy, thus, proposes SNCR technology to achieve a NO_x emission rate of 0.125 lb/million Btu on a 30-day rolling average for each boiler when combusting 100% wood fuel. The Permittee argues that the SNCR is the most common technology selected in other recent permit actions for boilers listed in the RBLC database and the NO_x emission limits for wood-fired boilers using SNCR in the RBLC database range from 0.15 to 0.25 lb/million Btu. Therefore, it concludes that the use of SNCR technology to achieve a NO_x emission rate of 0.125 lbs/million Btu on a 30-day rolling average using CEMS meets or exceeds SB3 State BACT.

DAQ Proposed BACT

DAQ agrees with the Permittee that the use of SNCR to achieve an emission rate of 0.125 lb/million Btu is a current BACT for NOx emissions from the wood-fired boilers at Lumberton Energy facility and thus approves them as SB3 BACT. The compliance with the BACT emission limit will be determined using CEMS on a 30-day rolling average basis.

7.6 BACT Analysis for VOC Emissions from Wood-fired Boilers

VOCs are emitted from wood-fired boilers as a result of incomplete combustion of the fuel. VOC emissions from wood-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design and turbulence. Control of incomplete combustion is accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

Potentially applicable VOC control technologies are:

- Catalytic Oxidation
- "Hot-side" Catalytic Oxidation
- Thermal Oxidation
- Good Combustion Practices

Catalytic Oxidation

Catalytic oxidation is a post-combustion control in which hydrocarbons (VOC) are oxidized in the presence of a catalyst (typically a precious metal that is usually deposited onto a solid honeycomb substrate) at specific temperatures to yield carbon dioxide (CO_2) and water. An acceptable flue gas temperature range for catalyst operation is 450°F–1,100°F. The oxidation process takes place spontaneously, without the requirement of introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion products to CO_2. Catalytic oxidation has been used primarily to control CO and VOC on combustion turbines firing natural gas.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorus and silica will act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also subject to masking and/or blinding by fly ash contained in the exhaust gas stream of a biomass-fired boiler. Because of the potential for oxidation catalyst fouling and/or deactivation on the biomass-fired boilers, the catalyst units have historically been located downstream of the particulate control device (fabric filter). When located downstream of the particulate control device, a supplemental burner is necessary to reheat the flue gas to the requisite temperature.

"Hot-side" Catalytic Oxidation

"Hot-side" catalytic oxidation utilizes the same oxidation process as described above but does not require a supplemental burner since the process is located upstream of the air heater within the acceptable flue gas temperature range for catalyst operation. However, the "hot-side" catalytic oxidation system must be used in conjunction with a hot-side ESP as the pre-treatment device, due to the operating temperature constraints. Without a particulate pretreatment device, the particulate-laden flue gas stream would foul the catalyst. Even with the hot-side ESP as the pretreatment device, the catalyst is still susceptible to blinding and/or poisoning by the fine particulates in the flue gas exiting the hot-side ESP.

Thermal Oxidation

Thermal oxidation employs high temperature combustion to achieve a 90 to 95 percent oxidation rate of VOC to CO_2 and water. The process reduces VOC by passing the gas stream through a high temperature region. It consists of a combustion chamber, a burner, and a heat exchanger/shell that preheats the incoming air. Thermal oxidizers are usually operated at 1,500°F–1,800°F.

The thermal oxidizer components are subject to fouling by PM. Accordingly, for biomass-fired boilers, the thermal oxidizer would need to be located downstream of the boiler's PM control device. In addition, a thermal oxidizer requires a source of supplemental fuel, typically natural gas, to raise the exhaust stream to the required oxidation temperature.

Good Combustion Practices

Good combustion controls are based on proper boiler design and proper operation of the boiler. Good combustion practices mean operation of the boiler at high combustion efficiency, thereby reducing products of incomplete combustion. Good combustion practices include operation at sufficiently high combustion temperatures, adequate residence time, adequate excess air and adequate turbulence, which ensures good mixing and availability of O_2 for efficient combustion. Reducing emissions of VOC can be accomplished by increasing the air available for combustion and/or the combustion temperature. However, these measures will increase NO_X emissions.

Thermal oxidation has primarily been applied on industrial exhaust streams to destroy VOCs and hazardous air pollutants (HAPs). Thermal oxidation is applicable only to gas streams with high levels of CO, VOCs and HAPs, such as chemical processing facilities, and not to the lower VOC concentrations exhaust stream from a well-designed and operated wood-fired boiler. The Permittee has concluded this control technique as technically infeasible because the wood-fired boilers of Lumberton Energy are essentially thermal oxidizers and their VOC emission rate would not be expected to decrease significantly from an add-on thermal oxidation process.

Therefore, catalytic oxidation and good combustion practices are the only demonstrated and technically feasible control measures for VOC reduction for the wood-fired boilers at this facility.

As per the Permittee, "Hot-side" catalytic oxidation has been proposed as BACT for the proposed Peregrine Energy Corporation (Peregrine) facility in Hartsville, South Carolina. The air permit application for the Peregrine facility is pending, so the technology has not yet been demonstrated based on actual operation. However, a cost effectiveness analysis has been prepared for "hot-side" catalytic oxidation and is discussed below.

The only VOC control technologies considered technically feasible for wood-fired boilers are good combustion practices and catalytic oxidation. The following Table provides a summary of the control efficiency ranges for the technically feasible VOC control technologies for spreader stoker wood-fired boilers.

CONTROL TECHNOLOGY	**CONTROL EFFICIENCY RANGE (%)**
Catalytic oxidation	Variable dependent upon inlet concentration
"Hot-side" catalytic oxidation	Variable dependent upon inlet concentration
Good combustion practices	25-50

The energy impacts associated with the installation and operation of this combination of control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as SB3 State BACT.

Economic Impact

Catalytic Oxidation

Retrofit installation of a catalytic oxidation system may require removal or relocation of existing equipment, increasing the costs over catalytic oxidation installation on a new boiler.

The Permittee has performed a cost evaluation of catalytic oxidation with the supplemental burner fired on a) natural gas b) No. 2 distillate fuel oil, and c) No. 6 residual fuel oil. The cost effectiveness ranged from approximately $261,670 to $337,243 per ton of VOC depending upon the fuel type for the supplemental burner. The Permittee has considered these costs prohibitive and therefore, catalytic oxidation is eliminated from further consideration in the SB3 State BACT evaluation. While the applicant believes that the cost is extremely high, the requirement of BACT prohibits the rejection of technology on a single factor and require a comprehensive evaluation of technology consistent with the definition of BACT.

Hot-side" Catalytic Oxidation

The retrofit installation of a "hot-side" catalytic oxidation system to the existing boilers would require extensive removal or relocation of existing equipment, including the demolition of the existing economizer and replacement with a new economizer, wall and roof penetrations to accommodate the new equipment, and fabrication and installation of new duct work and insulation. The extensive construction required for the retrofit installation increases the costs as compared to the "hot-side" catalytic oxidation installation on a new boiler such as the proposed Peregrine facility. Also, because of the temperature requirements of the flue gas and the need to have a clean flue gas stream due to poisoning/fouling issues with the catalyst, a hot-side ESP would be required to be installed prior to the "hot-side" oxidation catalyst. The additional cost of retrofit installation of a hot-side ESP (over the existing baghouse) was included in the cost of installing a "hot-side" oxidation catalyst. The equipment cost and additional cost of operating the hot-side ESP was not available for this BACT analysis and was therefore not included in the cost effectiveness evaluation.

The Permittee has performed a cost evaluation for "hot-side" catalytic oxidation, which indicates the cost effectiveness for "hot-side" catalytic oxidation of approximately $354,238 per ton of VOC removed. The Permittee has concluded this cost as prohibitive and has therefore eliminated "hot-side" catalytic oxidation from further consideration in the PSD BACT evaluation. While the applicant believes that the cost is extremely high, the requirement of BACT prohibits the rejection of technology on a single factor and require a comprehensive evaluation of technology consistent with the definition of BACT.

The Permittee states that it implements good combustion practices to achieve a VOC emission rate of 0.017 lb/million Btu on a 30-day rolling average for its wood-fired boilers. This technology is consistent with the technology selected on other recent permit actions for wood-fired boilers identified in the evaluation. VOC emission rates for similarly sized wood-fired boilers range from 0.013 to 0.095 lb/million Btu. The only facility utilizing oxidation catalysts identified in the RBLC query is Biomass Energy, LLC – South Point Power (SPP). SPP has a VOC emission rate of 0.012 lb/million Btu. As stated above, the SPP emission units were permitted but have never operated. Therefore, the use of an oxidation catalyst to reduce VOC emissions from a wood-fired boiler has not been demonstrated as feasible. Accordingly, the Permittee has concluded the implementation of good combustion practices to achieve a VOC emission rate of 0.017 lb/million Btu on a 30-day rolling average meets or exceeds SB3 State BACT.

DAQ Proposed BACT

DAQ believes that the Permittee may not be able to meet the emission limit of 0.017 lb/million Btu on a long-term basis. Thus, DAQ proposes to approve a more appropriate emission limit of 0.03 lb/million Btu using good combustion control as VOC BACT. The compliance with the BACT emission limit will be determined using a stack test on a 3-run average basis.

7.7 BACT Analysis for Hg Emissions from Wood-fired Boilers

Mercury (Hg) emissions are a function of fuel Hg content. Hg emissions will be low due to the low concentration of naturally occurring Hg in wood fuel. Mercury is expected to be present in wood in trace amounts attributable to root uptake from soil and deposition of airborne mercury to leaves, buds and bark.

During combustion, the resulting high combustion temperatures vaporize the Hg in the fuel to form elemental Hg vapor. Subsequent cooling of the combustion gases and interaction of the elemental Hg vapor with other combustion products result in a portion of the Hg being converted to other forms. There are three basic forms of H in the flue gas: 1) elemental Hg vapor; 2) compounds of oxidized Hg; and 3) particle-bound Hg. Hg in the flue gas is a mixture of these three forms of Hg.

Potentially applicable Hg control technologies are:

- Activated carbon injection
- Particulate wet scrubbers
- Electrostatic precipitators (ESPs)
- Fabric filters

Although, there is some amount of mercury removed as a co-benefit of NO_x and SO_2 emission controls, NO_x and SO_2 emission controls are not considered in this evaluation.

Activated Carbon Injection

Activated carbon injection refers to the injection of dry, powdered activated carbon into the flue gas duct between the air preheater and the particulate control device (either electrostatic precipitator (or fabric filter), typically in the 250 to 350°F range. The vapor phase Hg in the flue gas contacts the activated carbon and attached to its surface. The sorbent with the Hg attached is then collected in the particulate control device. The Hg/activated carbon reaction continues to occur in the ESP or baghouse, where additional adsorption takes place. Baghouse achieve higher Hg removal than ESPs because of the buildup of a carbon layer on the bag filters.

Particulate Wet Scrubbers

There are a number of different types of particulate wet scrubbers. All particulate wet scrubber designs utilize particle and/or droplet inertia as the fundamental force to transfer particles from the gas stream to the liquid stream. Within the scrubber, particle-laden air is forced to contact the liquid droplets, sheets of liquid on a packing material, or jets of liquid from a plate. Particles with too much inertia impact on the water droplet, water sheet, or water jet instead of passing around the "target" with the gas stream. Particulate wet scrubber types include venturis, impingement plate scrubbers, and spray towers.

Electrostatic Precipitators (ESPs)

ESPs remove particulate matter from a flue gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping.

Fabric Filters

A fabric filtration device (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through a layer of particulate and filter bags. The collected particulate forms a cake on the bag, which enhances the bag’s filtering efficiency.

The application of activated carbon injection technology on wood-fired boilers sized similarly to those at Lumberton Energy has not been demonstrated. Because, there are no technical demonstrations of activated carbon injection for wood-fired boilers sized similarly to those at Lumberton Energy, the Permittee has concluded this technology as technically infeasible.

All other control techniques; fabric filters, ESPs, mechanical collectors and particulate wet scrubbers, are technically feasible.

The control efficiency of particulate controls for Hg is highly variable depending on the Hg speciation. For Hg that is not in the vapor phase, control efficiencies will be similar to the control efficiencies for particulate matter. The following Table provides a summary of the control efficiency ranges for these technically feasible control technologies.

CONTROL TECHNOLOGY	CONTROL EFFICIENCY RANGE (%)
Fabric Filters	90-99
ESPs	90-99
Particulate wet scrubbers	25-65

The Permittee has provided below a more in-depth discussion on ranking of these technically feasible Hg control technologies:

1. Fabric filters have typical design efficiencies between 90 and 99%. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. The installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash reduces this hazard.

2. ESPs are the most common technology selected on other recent permit actions for boilers listed in the RBLC database. Collection efficiencies of 90 to 99 percent for PM have been observed for ESPs operating on wood-fired boilers.

3. The most widely used particulate wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 65 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

As noted above, mercury capture in particulate control devices depends on the Hg speciation at the inlet to the control device. The evaluation of the control effectiveness is based on compounds of oxidized Hg and particle-bound Hg.

Particulate wet scrubbers are simple in design and relatively low maintenance. However, one of the main disadvantages of particulate wet scrubbers is that they require make-up water to replace the water vaporized into the gas stream and lost to purge liquid and sludge removed from the scrubber system. Wet scrubbers also generate a waste stream in the form of a slurry or a wet sludge that must be treated properly. Disposal of the waste sludge is an added cost.

Wood-fired stoker boilers often use ESPs due to concerns over unburned carbon carryover, and the potential fire hazard that can result (i.e., hot carryover particles igniting the bags).

In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Bags are the most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured as cylindrical bags. Bags are generally 6 to 9 m (20 to 30 feet) in length and 13 to 31 cm (5 inches to 1 foot) in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Periodically, the cake is removed from the bags through physical mechanisms (e.g., a blast of compressed air from the "clean" side of the bag, reverse air, shaking bags etc.), which causes the cake to fall. The particulate is then collected in a hopper and periodically removed by the ash-handling system. Unlike ESPs, fabric filter capture of particulate matter is not based on the chemical and electrical or properties of the fly ash.

Fabric filters and ESPs have approximately equivalent removal efficiencies; however, ESPs are more sensitive to variations in gas stream conditions, such as flow rates, temperatures, particulate and gas composition, and particulate loadings. ESP particulate removal performance will therefore vary with the characteristics of the fuel. This is an important consideration given that characteristics of the wood fuel may vary widely. Fabric filters have better removal efficiencies of the smaller size or fines of the particulate matter (i.e. PM_{10}). In general, PM control technology effectiveness is expressed in terms of percent removal efficiency. It should be noted that the use of percent removal efficiency without specification of the gas stream conditions at the inlet to the control device is somewhat approximate because the percent removal efficiency vary as a function of the particle size distribution, particle characteristics, particulate matter loading, and velocity. Furthermore, it should be noted that the collection efficiency of a PM control device is generally higher when there is a high particulate loading entering the device.

Lumberton Energy proposes to utilize a fabric filter system to achieve an Hg emission rate of 5×10^{-6} lb/million Btu on a 30-day rolling average. As per the Permittee, there was only one permit determination identified in the RBLC database evaluation, which was for Biomass Energy, LLC – South Point Power (SPP). SPP has an Hg emission rate of 9.0×10^{-6} lb/million Btu. The SPP emission units were permitted but have never operated. The Permittee contends that use of fabric filter system meets or exceeds SB3 State BACT determinations for similar wood-fired boilers.

Finally, as discussed in Section 4.2.9 above, in the context of "area source" MACT/GACT for boilers, the EPA has not promulgated any emission standard for biomass-fired boilers. Also, in the context of "major source" MACT (which are currently stayed), EPA has determined that the fabric filters are the most effective technology employed by biomass-fired boilers for controlling mercury emissions.

DAQ Proposed BACT

DAQ agrees with the Permittee that the use of fabric filter to achieve an emission rate of 5×10^{-6} lb/million Btu is a current BACT for mercury emissions from the wood-fired boilers at Lumberton Energy facility and thus approves them as SB3 BACT. The compliance with the BACT emission limit will be determined using a stack test on a 3-hour average basis.

7.8 SB3 BACT Summary

The following Table presents a summary, consisting of DAQ proposed SB3 BACT for approval, for emissions of PM/PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, and Hg, from wood-fired boilers:

EMISSION SOURCE	POLLUTANT	EMISSION LIMITS	CONTROL TECHNOLOGY
Boilers **(ID Nos. ES-1A and ES-1B)**	PM/PM_{10}	0.036 lb/million Btu (both filterable and condensable) [stack test: 3-run average]	multiclone and bagfilter
	$PM_{2.5}$	0.011 lb/million Btu (both filterable and condensable [organic and inorganic including sulfuric acid mist]) [stack test: 3-run average]	multiclone and bagfilter
	SO_2	0.025 lb/million Btu [CEM: 30-day rolling average]	use of low sulfur wood
	NOx	0.125 lb/million Btu [CEM: 30-day rolling average]	selective non-catalytic reduction
	VOC	0.03 lb/million Btu [stack test: 3-run average]	good combustion control
	Hg	5×10^{-6} lb/million Btu [stack test: 3-run average]	bagfilter

APPENDIX A

Sample Emission Calculations

APPENDIX B

Draft Permit

APPENDIX C

Public Notice

APPENDIX D

RBLC NCDAQ Search Summary

APPENDIX E

Application