AIR PERMIT APPLICATION REVIEW/PRELIMINARY DETERMINATION

APPLICANT:	**SITE LOCATION:**		**COUNTY:**
Hertford Renewable Energy, LLC	Aulander		Hertford
TECHNICAL CONTACT:	**PHONE:**	**RESPONSIBLE OFFICIAL:**	**TITLE:**
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APPLICATION NUMBER:	**EXISTING PERMIT NUMBER:**		**NEW PERMIT NUMBER:**
4600104.08A	NA		09947R00

I. Purpose of the Application

Hertford Renewable Energy, LLC (HRE) is a wholly owned subsidiary of Decker Energy International, Inc. (Decker) that plans to construct and operate a 60 megawatt (MW) biomass-fired power plant located in Aulander, Hertford County, North Carolina. The facility will be classified as a major stationary source for the purpose of the Prevention of Significant Deterioration (PSD) permitting program (see 15A NCAC 2D .0530 analysis below). HRE has proposed the installation of one (1) new 60 MW unadulterated wood-fired boiler that will fire biodiesel (B100) for startup, fuel handling and pollution control equipment, one emergency generator, one fire water pump, and one cooling tower. Note that HRE had originally proposed to install two (2) new 50 MW unadulterated wood-fired boilers and associated equipment, but that application was amended on May 29, 2009. (Copy of the amended application is included as Appendix A to this report). The application was also amended on July 31, 2009 to revise the boiler hydrogen chloride (HCl) emission factor that resulted in the retraction of control equipment (dry sorbent injection and associated silo) for acid gas (HCl) removal. (Copy of the amended application is included as Appendix B to this report). The emission increases resulting from the operation of this boiler and ancillary equipment exceed the PSD significance levels for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 micrometers or less (PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOCs) and therefore triggers the PSD permitting requirements.

This greenfield facility will be processed under 15A NCAC 2D .0530 and 2Q .0300 and issued a construction and operation permit (09947R00) after completion of the review and public notice periods. Since these are new emissions units they are not covered under an existing permit; therefore, this modification would not contravene or conflict with any existing permit term or condition. As such, 15A NCAC 2Q .0501(c)(2) provides that a construction and operation permit may be issued under the procedures of 2Q .0504, and within 12 months of commencing operation an application must be submitted to meet the full Title V processing requirements per 2Q .0500.

II. Background

The HRE facility will burn clean wood waste to produce electricity for sale to the power transmission grid as an independent power producer (IPP). The facility will be comprised of one 60 MW biomass-fired boiler and ancillary equipment. The proposed new equipment will consist of the following:

- A fuel receiving yard;
- Fuel handling equipment;
- One 60 MW biomass-fired power boiler;
- Pollution control equipment, including a multi-cyclonic dust collector and electrostatic precipitator for particulate matter abatement, and selective noncatalytic reduction (SNCR) for NO_x reduction for the power boiler and fabric filtration and dust suppression systems for the ash storage silo;
- A steam turbine with condenser;
- A cooling tower;
- A 250 kW No. 2 fuel oil-fired emergency electric generator;
- A 400 hp No. 2 fuel oil-fired fire water pump;
- A step up transformer and various interconnect equipment; and
- Water supply and waste water discharge systems.

III. Regulatory Summary

The following is a list of all air quality regulations applicable to the above equipment:

A. **One unadulterated wood-fired boiler (858 million Btu per hour maximum heat input, ID No. ES-BLR-1)** – the following is a list of all air quality regulations applicable to the boiler:

2D .0503 "Particulate from Fuel Burning Indirect Heat Exchangers"

This regulation applies to this fuel (biodiesel during startup) burning indirect heat exchanger. The particulate matter emissions are limited to 0.27 pounds per hour based on the equation $E = 1.090\ Q^{-0.2594}$ where E is the allowable emission limit for particulate matter in pounds per million Btu and Q is the maximum heat input in million Btu per hour noting that firing biodiesel during startup will be 25 percent (215 million Btu per hour) of the maximum heat input capacity of the boiler.
Because the BACT limit is more stringent than the 2D .0503 limit, compliance is expected with 2D .0503.

2D .0504 "Particulate from Wood Burning Indirect Heat Exchangers"

This regulation applies to this wood burning indirect heat exchanger. The particulate matter emissions are limited to 0.26 pounds per hour based on the equation $E = 1.1698\ Q^{-0.2230}$ where E is the allowable emission limit for particulate matter in pounds per million Btu and Q is the maximum heat input in million Btu per hour.
Because the BACT limit is more stringent than the 2D .0504 limit, compliance is expected with 2D .0504.

2D .0524 "New Source Performance Standard" – NSPS Subpart Db

This regulation applies to the new boiler since it will have a heat input capacity greater than 100 million Btu per hour (MMBtu/hr), will be constructed after June 19, 1984 and will not fire fossil fuels. Based on the proposed fuel (biomass and biodiesel) that will be burned in the boiler, the particulate matter standards (§60.43b) are applicable. Sulfur dioxide (§60.42b) and nitrogen oxide (§60.44b) standards are not applicable to biomass or biodiesel fuel.

Under NSPS Subpart Db, the standard for particulate matter for a unit that burns wood is 0.030 lb/MMBTU and the opacity limit is 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity (§60.43b(f) and (h)(1)). The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction (§60.43b(g)).

Initial performance tests will be required for each boiler regulated by this subpart using Method 5 for particulate matter (§60.46b(d)) and Method 9 for opacity (§60.46b(d)(7)). In accordance with §60.48b(a) the affected facility must install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

Other record keeping and reporting requirements outlined in §60.49b will also apply to the boilers. Specifically, §60.49b(a) sets forth the initial reporting requirements of §60.7. Notification of the date construction is commenced must be postmarked no later than 30 days after the construction starts. Notification of the actual date of initial start-up must be postmarked within 15 days of the actual start date. §60.49b(a)(1) also requires the reporting of the design heat input capacity of the boiler and identification of fuels that will be burned. §60.49b(b) requires the affected facility to submit performance test data from the initial performance test.

§60.49b(d) requires the affected facility to record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. HRE requests that there be no requirement to record the amount of fuel used each day. The amount of wood and/or biodiesel burned in the boiler daily does not change the applicability of Subpart Db. In an October 2005 applicability determination, EPA determined that for a facility that combusts only wood the requirement to record the amount of wood combusted each day is not needed for the purposes of calculating the annual capacity factor.[1] Additionally, biodiesel is not one of the fuels listed in the requirement to calculate the annual capacity factor.
§60.49b(f) requires the facility to maintain records of opacity.

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[1] Letter from Jeff KenKnight, Manager Federal and Delegated Air Programs Unit Michael Scott Atkison, CEO Bennett Forest Industries. (Applicability Determination Control Number: 0700014)

Compliance is expected with NSPS Subpart Db.

2D .0530 "Prevention of Significant Deterioration"

This regulation is applicable to the new equipment and the details of the regulation are provided in section IV of this report.

B. One No. 2 fuel oil-fired emergency generator (ID No. ES-EG) and one No. 2 fuel oil-fired fire water pump (ID No. ES-FW) – the following is a list of all air quality regulations applicable to the generator and the pump:

2D .0516 "Sulfur Dioxide Emissions from Combustion Sources"

This regulation applies to both since they burn low sulfur (0.0015 percent by weight sulfur) No. 2 fuel oil. Sulfur dioxide emissions shall be limited to less than 2.3 pounds per million Btu heat input. Compliance is expected with 2D .0516.

2D .0521 "Control of Visible Emissions"

This regulation limits visible emissions from all sources manufactured after July 1, 1971 to less than 20% opacity averaged over a 6-minute period with the exceptions noted in the regulation. Compliance is expected with 2D .0521.

2D .0524 "New Source Performance Standards" NSPS Subpart IIII

NSPS Subpart IIII applies to owners or operators of compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006 that are not fire pump engines, and fire pump engines manufactured after July 1, 2006. HRE has proposed a 250 KW (450 hp) emergency generator and a 400 hp fire pump. The emergency generator and fire pump will have been manufactured after the dates specified above. Therefore, the emergency generator and fire pump are subject to the provisions of NSPS Subpart IIII.

Under NSPS Subpart IIII, owners and operators of emergency generators manufactured in CY 2007 or later with a maximum engine power greater than or equal to 50 hp are required to comply with the emission limits referenced in 40 CFR 60.4205(b) that refers to 40 CFR 60.4202(a)(2). These limits are from 40 CFR 89.112 (Table 1) and are as follows: 0.20 g/kW for PM, 3.5 g/kW for CO, and 4 g/kW for NO_x + nonmethane hydrocarbons (NMHC).

HRE will comply with the emission limits by operating the generator as instructed in the manufacturer's operating manual in accordance with 40 CFR §60.4211(a), and purchasing an engine certified to meet the referenced emission limits in accordance with 40 CFR §60.4211(c). The engine will be equipped with a non-resettable hour meter in accordance with 40 CFR §60.4209(a). Emergency and readiness testing of the unit will be limited to 100 hours per year. No recordkeeping or reporting will be required for the emergency generator.

In accordance with NSPS Subpart IIII, owners and operators of fire pump engines manufactured after July 1, 2006 must comply with the emission limits in Table 4 of NSPS Subpart IIII, which are organized based on the size of the unit. These limits are as follows: 0.20 g/kW for PM, 3.5 g/kW for CO, and 4 g/kW for NO_x + NMHC.

HRE will comply with these emission limits by operating the fire pump as instructed in the manufacturer's operating manual in accordance with 40 CFR §60.4211(a), and purchasing an engine certified to meet the referenced emission limits in accordance with 40 CFR §60.4211(b). The engine will be equipped with a non-resettable hour meter in accordance with 40 CFR §60.4209(a). Emergency and readiness testing of the unit will be limited to 100 hours per year. No recordkeeping or reporting will be required for the fire pump. Additionally, no initial notification under §60.7(a)(1) is required (§60.4214(b)).

In addition, both the proposed emergency generator and fire pump will be required to comply with the fuel requirements in 40 CFR §60.4207, which limit sulfur to a maximum of 500 ppmw beginning October 1, 2007 and 15 ppmw beginning October 1, 2010.

2D .0530 "Prevention of Significant Deterioration"

This regulation is applicable to the new equipment and the details of the regulation are provided in section IV of this report.

2D .1111 "Maximum Achievable Control Technology" MACT Subpart ZZZZ

MACT Subpart ZZZZ applies to reciprocating internal combustion engines (RICE) located at a major or area source of HAP emissions (noting that HRE has requested an avoidance limit of less than 10 tons per year (tpy) per individual hazardous air pollutant (HAP) or 25 tpy for aggregate HAP). An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Emergency power and limited use units are subject to limited requirements under 40 CFR 63.6590(b)(i) and 40 CFR 63.6590(b)(ii). Emergency stationary RICE are defined in 40 CFR 63.6675 as any stationary RICE that operates in an emergency situation. These situations include engines used for power generation when power from the local utility is interrupted, or engines used to pump water in the case of fire or flood. The proposed emergency generator and the emergency fire pump at HRE will be classified as emergency stationary RICE under the RICE NESHAP and will comply with the requirements listed under this subpart. Compliance is expected with 2D .1111 (MACT Subpart ZZZZ).

C. One four-cell cooling tower (ID No. ES-CT-1) – the following is a list of all air quality regulations applicable to the cooling tower:

2D .0515 "Particulate from Miscellaneous Industrial Processes"

This regulation applies to the cooling tower. Hot circulating water from the steam cycle is recirculated through cooling tower. Cooling tower drift will be minimized to 0.0005 percent of the design recirculation rate using state of the art high efficiency drift eliminators. Emissions from these towers are based on recirculation rate, drift loss and design total dissolved solids content of the recirculating water. Compliance is expected with 2D .0515.

2D .0521 "Control of Visible Emissions"

This regulation limits visible emissions from all sources manufactured after July 1, 1971 to less than 20% opacity averaged over a 6-minute period with the exceptions noted in the regulation. Compliance is expected with 2D .0521.

2D .0530 "Prevention of Significant Deterioration"

This regulation is applicable to the new equipment and the details of the regulation are provided in section IV of this report.

IV. Prevention of Significant Deterioration

As noted above the 60 MW power boiler has potential emissions that exceed the PSD significance levels. The table below summarizes the emission estimates. The estimates were based on an expected worst case (normally unadulterated wood-fired however biodiesel-fired during startup at 25 percent of maximum heat input).

Source Description	CO (tpy)	NO_x (tpy)	TSP (tpy)	PM-10 (tpy)	SO_2 (tpy)	VOC (tpy)	Pb (tpy)	F (tpy)
One (1) unadulterated wood-fired boiler (858 million Btu per hour maximum heat input, ID No. ES-BLR)	939.7	375.9	139.1	139.1	94.0	63.9	0.18	0.25
One (1) flyash silo (ID No. ES-FS)			1.23 E-4	1.23 E-4				
One (1) four-cell cooling tower (43,441 gallons per hour recirculation water flow rate, ID No. ES-CT)			1.90	0.76				
One (1) diesel-fired emergency generator (450 horsepower, ID No. ES-EG)	0.64	0.73	3.67 E-2	3.67 E-2	1.03 E-3	1.67 E-3		
One (1) diesel-fired fire water pump (400 horsepower, ID No. ES-FWP)	0.64	0.73	3.67 E-2	3.67 E-2	1.03 E-3	1.67 E-3		
One (1) biodiesel storage tank (ID No. ES-BT)						4.86 E-2		
Total Emission Increases	941.0	377.4	141.1	139.9	94.0	63.9	0.18	0.25
PSD Significant Emission Rates	100	40	25	15	40	40	0.6	3
PSD Review Required	Yes	Yes	Yes	Yes	Yes	Yes	No	No

Under the PSD requirements, all new or modified major stationary sources of air pollutants regulated under the Clean Air Act (CAA) must undergo a preconstruction review consistent with Section 165 of the Act prior to Abegin[ning] actual construction.≅ A "major stationary source" is defined as any one of 28 named source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. HRE is not one of the listed source categories with a 100 ton per year threshold; therefore, the major source threshold for the proposed facility is 250 tpy of any regulated pollutant. *See 40 CFR 51.166 (b)(23).*

HRE has a potential to emit of a greater than 250 tpy of CO and NO_x; therefore, the facility is classified as a PSD major stationary source. The HRE plant will be located in near Aulander, Hertford County, North Carolina. This area is classified as attainment with respect to the National Ambient Air Quality Standards (NAAQS) for particulate, sulfur dioxide, ozone, nitrogen dioxide, carbon monoxide and lead. Because the area is classified as attainment for all pollutants, no pollutants are subject to nonattainment review. This area is considered a Class II area with allowable PSD increments for PM-10, SO_2, and NO_X emissions.

Because the facility is major, each pollutant with a "potential to emit" greater than the "significance" levels is subject to PSD regulations and must meet certain review requirements. As noted above CO, NO_x, PM, SO_2 and VOC emissions all exceed their respective PSD significance levels and are therefore subject to PSD. HRE submitted the following reviews and analyses required for PSD review for each subject pollutant:

1) A Best Available Control Technology (BACT) Determination as determined by the permitting agency on a case-by-case basis in accordance with 40 CFR 51.166(j),
2) An Air Quality Impacts Analysis was included as part of the application because all the pollutants noted above exceed their corresponding significant emission rate (SER) while modeling results were above the Class II Area significant impact levels (SILs) for PM-10 for both the annual and 24-hour PM-10 averaging periods.
3) An Additional Impacts Analysis including effects on soils and vegetation, and impacts on visibility[2] in accordance with 40 CFR 51.166(o).
4) Class I impact analysis was not included because the Federal Land Manager for the closest Class I area was contacted and did not require any analyses to be performed.

Under PSD regulations, the basic control technology requirement is the evaluation and application of BACT. BACT is defined as follows [40 CFR 51.155 (b)(12)]:

> ***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.***

[2]The visibility impacts to be evaluated under this subparagraph of the PSD rules is distinct from the Class I AQRV analysis.

As evidenced by the statutory definition of BACT, this technology determination must include a consideration of numerous factors. The structural and procedural framework upon which a decision should be made is not prescribed by Congress under the Act. This void in procedure has been filled by what several guidance documents issued by the federal EPA. The only final guidance available is the October 1980 "Prevention of Significant Deterioration – Workshop Manual." As the EPA states on page II-B-1, "A BACT determination is dependent on the specific nature of the factors for that **particular case**. The depth of a BACT analysis should be based on the quantity and type of pollutants emitted and the **degree of expected air quality impacts**." (emphasis added). The EPA has issued additional DRAFT guidance suggesting the use of what they refer to as a "top-down" BACT determination method. While the EPA Environmental Appeals Board recognizes the Atop-down≅ approach for delegated state agencies,[3] this procedure has never undergone rulemaking and as such, the Atop-down≅ process is not binding on fully approved states, including North Carolina.[4] The Division prefers to follow closely the statutory language when making a BACT determination and therefore bases the determination on an evaluation of the statutory factors contained in the definition of BACT in the Clean Air Act. As stated in the legislative history and in EPA's final October 1980 PSD Workshop Manual, each case is different and the state must decide how to weigh each of the various BACT factors. North Carolina is concerned that the application of EPA's DRAFT suggested Atop-down≅ process will result in decisions that are inconsistent with the Congressional intent of PSD and BACT. The following are passages from the legislative history of the Clean Air Act and provide valuable insight for state agencies when making BACT decisions.

> The decision regarding the actual implementation of best available technology is a key one, and the **committee places this responsibility with the State**, to be determined on a case-by-case judgment. It is recognized that the phrase has broad flexibility in how it should and can be interpreted, depending on site.
>
> In making this key decision on the technology to be used, the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. **The weight to be assigned to such factors is to be determined by the State**. Such a flexible approach allows the adoption of improvements in technology to become widespread far more rapidly than would occur with a uniform Federal standard. The only Federal guidelines are the EPA new source performance and hazardous emissions standards, which represent a floor for the State=s decision.

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[3] See, http://es.epa.gov/oeca/enforcement/envappeal.html for various PSD appeals board decisions including standard for review.

[4] North Carolina has full authority to implement the PSD program, 40 CFR Sec. 52.1770

This directive enables the State to consider the size of the plant, the increment of air quality which will be absorbed by any particular major emitting facility, and such other considerations as anticipated and desired economic growth for the area. This allows the States and local communities judge how much of the defined increment of significant deterioration will be devoted to any major emitting facility. If, under the design which a major facility proposes, the percentage of increment would effectively prevent growth after the proposed major facility was completed, the State or local community could refuse to permit construction, or limit its size. **This is strictly a State and local decision; this legislation provides the parameters for that decision.**

One of the cornerstones of a policy to keep clean areas clean is to require that new sources use the best available technology available to clean up pollution. One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country in not applicable at a new facility in another area because of the differences in feedstock material, plant configuration, or other reasons. **For this and other reasons the Committee voted to permit emission limits based on the best available technology on a case-by-case judgement at the State level.** [**emphasis added**]. This flexibility should allow for such differences to be accommodated and still maximize the use of improved technology.

Legislative History of the Clean Air Act Amendments of 1977

A. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) –

The proposed greenfield power generation facility is subject to BACT review. As discussed earlier the applicant estimated the uncontrolled emissions (See application for details of emission estimates).

1. **BACT Analysis for Nitrogen Oxide (NO_x) emissions** – NO_x emissions have adverse health effects and play a role in ground level ozone formation, acid rain deposition, global warming (potentially), water quality degradation, reduced visibility, and the formation of toxic air pollutants. The most abundant forms of NO_x emissions from combustion sources are nitric oxide (NO) and nitrogen dioxide (NO_2). Nitric oxide is an odorless, colorless, toxic gas. NO_2 is also a toxic gas, but unlike NO, it is highly corrosive with a pungent odor and a reddish-brown appearance. Over time, in the presence of oxygen, most NO is converted to NO_2. The reddish brown NO_2 gas blocks the transmission of light, reduces visibility, and creates haze. NO_x emissions also increase nitrogen loading in coastal estuaries and upset the chemical balance of nutrients used by aquatic plants and animals. Elevated nitrogen levels promote excessive plant growth, which eventually leads to oxygen depletion and reductions in fish and shellfish populations

   During combustion, NO_x is formed through the high temperature oxidation of the diatomic nitrogen found in combustion air (thermal NO_x) and through the release of the nitrogen bound in the fuel, which ultimately reacts to forms NO_x (fuel NO_x). Almost all of the NO_x from natural gas combustion is thermal NO_x, while up to half of the NO_x from fuel oil combustion is fuel NO_x. Thermal NO_x formation is a function of the combustion temperature and the residence time of nitrogen at that temperature. NO_x production increases exponentially with increases in combustion temperature.

   a. **BACT for the Power Boiler**

      i. The applicant evaluated the following **control technologies** for NO_x emissions:

         I) **Selective Catalytic Reduction (SCR)** – This technology is a post combustion add-on control technology that is placed in the flue gas stream following the boiler. SCR utilizes ammonia (NH_3) that is typically drawn from a storage tank, vaporized and injected upstream of the catalyst bed. Excess NH_3 that is not reacted in the catalyst bed and emitted is referred to as ammonia slip. An important factor that affects the performance of an SCR is operating temperature. The temperature range for standard base metal catalyst is between 400-800 ºF. In order for the catalytic system to operate at an ideal operating temperature, SCR is installed after the last heat transfer surface in the boiler but prior to the particulate matter control device. Therefore, the flue gas can be laden with ash particles due to its location upstream of an electrostatic precipitator or a fabric filter. These particles have the potential to poison and "blind" the SCR catalyst. Wood ash particles can be especially problematic for this type of system, and no projects implementing SCR systems on wood-fired boilers could be found during the research conducted for this modification. Therefore, SCR is not considered to be technically feasible for this project and will **not** be considered further.

II) **Regenerative Selective Catalytic Reduction (RSCR)** – Babcock Power Inc. has developed a new SCR system that can be installed after the final particulate matter emissions controls. This technology is post combustion add-on control technology that utilizes beds of ceramic media to raise the temperature of the flue gas after particulate control to a temperature (~350 ºF) needed for the reaction. NH_3 reacts with NO_x and reduces to form nitrogen gas (N_2) and water (H_2O). The flue gas passes through a preheated bed where it is heated from 350 ºF to 450 ºF. Burners then raise the flue gas temperature to 470 ºF before it flows across the adjacent catalyst canister, where NOx reduction occurs. The exhaust gas from the catalyst bed then heats an adjacent bed containing heat transfer media. This heated bed then becomes the preheater for the exhaust. Flow direction continues to alternate in this fashion. The RSCR system operates in a cleaner environment and provides improved catalyst performance and high thermal efficiency. Therefore, RSCR is considered to be technically feasible and will be considered further.

III) **Selective Non-Catalytic Reduction (SNCR)** – This technology is a post combustion add-on control technology that injects ammonia or urea into the flue gas stream ahead of a catalyst bed where ammonia or urea reacts with NO_x that is reduced to form N_2 and H_2O. Typically, injection nozzles are located in the upper area of the furnace and convective passes. Once injected, the urea or ammonia decomposes into NH_3 or NH_2 free radicals, reacts with NO_X molecules, and reduces to nitrogen and water.

Both ammonia and urea have been successfully employed as reagents in SNCR systems and have certain advantages and disadvantages. Ammonia is less expensive than urea and results in substantially less operating costs at comparable levels of effectiveness. Urea, however, is able to penetrate further into flue gas streams, making it more effective in larger scale burners and combustion units with high exhaust flow rates. In addition, ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP).

SNCR is considered a selective chemical process because, under a specific temperature range, the reduction reactions described above are favored over reactions with other flue gas components. Although other operating parameters such as residence time and oxygen availability can significantly affect performance, temperature remains one of the most prominent factors affecting SNCR performance.

The SNCR process requires the installation of reagent storage facilities, a system capable of metering and diluting the stock reagent into the appropriate solution, and an atomization/injection system at the appropriate locations in the combustion unit. The reagent solution is typically injected along the post-combustion section of the combustion unit. Injection sites around the unit must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature.

For ammonia, the optimum reaction temperature range is 879 to 1,100 degrees Celsius (°C) (1,615 to 2,000 °F), while optimum urea reaction temperature ranges are marginally higher at 900 to 1,150 °C (1,650 to 2,100 °F).[5] Below the SNCR operating temperature range, the NH_3/NOx reaction will not occur. The unreacted NH_3 will either be emitted as NH_3 slip or it will react with SO_3 to form ammonium salts. Above the optimal temperature range, the amount of NH_3 that oxidizes to NOx increases and NOx reduction performance deteriorates. The temperature of the flue gas stream in the upper area of the furnace is normally in the proper operation range for SNCR. Therefore, SNCR is considered to be technically feasible and will be considered further.

The technically feasible control technologies for the proposed wood-fired power boiler offering the greatest NOx reduction include RSCR and SNCR. The applicant evaluated the practicality of these controls for the proposed boiler. After extensive collaboration between the boiler manufacturer and a major SNCR vendor, an SNCR control option of 0.10 lb/MM Btu was determined to be the lowest achievable level and was included in the BACT evaluation.

ii. Therefore, the **economic, environmental, and energy impacts** of RSCR and SNCR are further evaluated.

I) <u>**RSCR**</u>

A) **Economic impact** – The applicant estimated the cost of this system based on a 70% reduction efficiency. The uncontrolled emission rate based using worst case (i.e. highest expected usage) emission estimates is 939.5 tons per year from the power boiler. At an overall reduction efficiency of 70% the resulting emission reduction would be 657.7 tons per year. The total capital cost of the RSCR (direct and indirect capital cost) was estimated to be $10,332,490. The annualized cost of this capital, based on a 10% interest rate (which is considered conservative) and a useful life of 15 years, was estimated at $1,771,751 per year.[6] The annual operating costs were estimated

[5] U.S. EPA, "Air Pollution Control Technology Fact Sheet; Selective Non-catalytic Reduction", EPA-452/F-03-031, p. 2.
[6] The useful life and %ROI were discussed on several occasions with the facility and DAQ and its was agreed that these numbers represented a reasonable assumptions.

to be $2,369,029. The total annualized cost of the RSCR was estimated to be $4,140,780. With an emission reduction of 657.7 tons per year the average cost effectiveness was $6,296 per ton of NO_x removed. The incremental cost effectiveness between this option and the next most efficient control option, SNCR (see below), is $27,882 per additional ton of NO_x removed. (Annual cost differential of $2,620,974 for an additional 94 ton annual reduction).

B) **<u>Environmental Impact</u>** – The Clean Air Act requires the permitting authority to consider environmental impacts when making a BACT determination. *See* 42 U.S.C. 7479(3). The EPA issued guidance on BACT determinations including the appropriate use of the statutory BACT factors. This guidance is contained in a manual entitled ANew Source Review Workshop Manual≅ (Draft, October 1990). On p. B.49 EPA describes examples of environmental impacts that may be considered. They state,

> One environmental impact that could be examined is the trade-off between emissions of various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emission of pollutants other than those the technology was designed to control.

Final EPA guidance suggests that when making a BACT determination the “direct and residual risks with, and impacts on, environmental factors must be considered.” (Prevention of Significant Deterioration Workshop Manual, USEPA, October 1980, page I-B-2). This guidance, consistent with the aforementioned statutory scheme, specifically requires that “An air quality impact analysis should be included in the environmental impact analysis. It should consider the maximum ground-level impact and ground-level concentrations that would result from the emissions from the proposed new source or modification after each control strategy is applied.” (Id. at I-B-13).

Ammonia slip from the RSCR system will be considered an environmental impact since ammonia is listed as an acute irritant under the North Carolina Air Toxics Program, considered a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA), and regulated by US EPA’s Chemical Accident Prevention Provisions. Also, the spent catalyst will be considered a hazardous waste due to its vanadium content and possibly other trace metals and must be properly handled and disposed of following the appropriate regulatory procedures.

C) **Energy Impact** - The Clean Air Act requires the permitting authority to consider energy impacts when making a BACT determination. *See* 42 U.S.C. 7479(3), CAA Section 169(3).

The EPA issued guidance on BACT determinations including the appropriate use of the statutory BACT factors. This guidance is contained in a manual entitled ANew Source Review Workshop Manual≅ (Draft, October 1990). On p.B.29 EPA describes the type of energy impacts that can be considered. They state,

> Applicants should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; or on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream.

There is typically an adverse energy penalty associated with fan power necessary to overcome the pressure drop across the catalyst bed. This energy penalty was not further detailed.

II) **SNCR**

A) **Economic Impact** – The applicant estimated the cost of this system based on a 60% reduction efficiency. The uncontrolled emission rate based using worst case (i.e. highest expected usage) emission estimates is 939.5 tons per year from the power boiler. At an overall reduction efficiency of 60% the resulting emission reduction would be 563.7 tons per year. The total capital cost of the SNCR (direct and indirect capital cost) was estimated to be $1,906,910. The annualized cost of this capital, based on a 10% interest rate (which is considered conservative) and a useful life of 15 years, was estimated at $326,985 per year.[7] The annual operating costs were estimated to be $1,192,821. The total annualized cost of the SNCR was estimated to be $1,519,806. With an emission reduction of 563.7 tons per year the average cost effectiveness was $2696 per ton of NO_x removed.

B) **Environmental Impact** – Some environmental impact is expected from the ammonia slip from the SNCR system outside the operating temperature range; however, that should be minimized since the applicant has proposed to utilize urea as the reagent rather than ammonia. Also, the SNCR does not have the

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[7] The useful life and %ROI were discussed on several occasions with the facility and DAQ and its was agreed that these numbers represented a reasonable assumptions.

adverse environmental impact associated with catalyst cleaning and disposal.

C) **Energy Impact -** Some energy impact is expected from the use of SNCR to control NOx emissions. Unreacted ammonia will react with sulfur trioxide to form ammonium salts or will be incorporated with the ash. Ammonium sulfates can also cause fouling of baghouse fabric filters. These deposits can cause a significant pressure drop across the baghouse. As the pressure drop increases, the boiler capacity will reduce because the boiler fans will not be able to maintain design combustion air flows at the higher bag house pressure drop.

Therefore, DAQ selects SNCR as BACT for NO_x emissions with an emission limit of 0.10 pounds per million Btu heat input (lb/MMBtu) for the power boiler. Compliance with the above limit will be determined utilizing a continuous emission monitoring system (CEMS) over a 30 day average.

b. **<u>BACT for the Emergency Generator and Emergency Fire Water Pump Engine</u>** – The proposed emergency generator and emergency fire water pump engine are sources of NO_x. NO_x are emitted from these combustion sources as a function of the fuel being burned. The emergency generator will be limited to 500 hours per year. The firewater pump will be used a maximum of 100 hours per year for readiness testing. Add-on controls are impractical given the intermittent operation of these sources. BACT is proposed to be (4.0 g/kW-hr that is combined with VOC) the same as the NSPS Subpart IIII standard as discussed in Section III. B. above.

2. **BACT Analysis for Carbon Monoxide (CO) and Volatile Organic Compound (VOC) emissions** - CO is a colorless, odorless, tasteless and toxic gas produced as a by-product of incomplete combustion. CO emissions have adverse health effects and play a role in ground level ozone formation. The highest levels of CO in the outside air occur during periods of nighttime inversions when an upper layer of warm air traps CO near the ground, usually in the colder months of the year.
VOCs result from incomplete combustion as well. Unburned hydrocarbons consist of VOCs, which contribute to ground level ozone, and methane and ethane which do not produce ozone. VOCs are also significant greenhouse gases via their role in creating ozone and in prolonging the life of methane in the atmosphere. Aromatic VOC compounds such as benzene, toluene, and xylene are suspected carinogens.

   CO and VOC emissions from the power boiler are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. CO control methods include combustion control to suppress CO formation and post-combustion control, such as regenerative catalytic oxidation, to remove the CO from the flue gas. Combustion control techniques, including increased fuel residence time and increased combustion zone temperature, minimize incomplete combustion and CO formation. However, because increases in thermal NO_x formation are related to increases in the combustion temperature and the residence time of nitrogen at that temperature, care must be exercised when using combustion control. At higher combustion temperatures and longer residence times, NO_x formation is substantially greater. Conversely, a low NO_x emission rate achieved through flame temperature control results in higher CO emissions. Thus, a balance must be established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels. In North Carolina, NO_x is a more important pollutant to control because it is a precursor to ozone formation.

   a. **BACT for the Power Boiler**

      i. The applicant evaluated the following **control technologies** for CO and VOC emissions:

         I) **Good Combustion Practices (GCP)** - Good combustion control practices rely on efficient operation of the boiler. Emissions of CO and VOC are minimized due to better combustion efficiency through optimum design and operation of the boiler. This includes proper air-to-fuel ratios and a boiler design that provides the sufficiently high combustion temperature, adequate residence time and mixing conditions (adequate excess air and turbulence) in the combustion zone. As a result of economic incentives as well as air pollution concerns, manufacturers have attempted to maximize the combustion efficiency of boilers.

II) **<u>Regenerative Catalytic Oxidation (RCO)</u>** – Regenerative catalytic oxidation is an add-on or post-combustion control used to promote the oxidation of CO to carbon dioxide (CO_2) by lowering the activation energy of the reaction. Boiler exhaust gases containing CO, VOCs and O_2 pass through a catalyst bed (typically platinum/rhodium) and react to form CO_2 and H_2O. RCO is the only oxidation technology evaluated because it requires only moderate reheating to a minimum temperature of 450 ^{o}F. Furthermore, RCOs can achieve a high thermal efficiency of 95% because they utilize a ceramic bed to recapture the heat of the stream exiting the combustion zone. Particulate control must be placed upstream of an RCO. Even with highly efficient PM_{10} control, there is the risk of catalyst blinding/poisoning and catalyst life guarantees are relatively short. RCO is a technically feasible option for boilers burning wood. Control efficiencies typically range from 50 to 60 percent.

ii. Therefore, the **economic, environmental, and energy impacts** of GCP and RCO are further evaluated.

I) **<u>GCP</u>** **-** No adverse economic, environmental, or energy impacts are expected from the use of GCP to control CO and VOC emissions.

II) **<u>RCO</u>**

A) **<u>Economic Impact</u>** - A detailed cost evaluation of an RCO is included in Table 4-15. As shown in Table 4-16, a cost effectiveness of approximately $5,400 per ton of CO was estimated. Table 4-18 shows an estimated cost effectiveness of approximately $95,800 per ton of VOC.

B) **<u>Environmental Impact</u>** – Wood ash particles have the potential to poison and “blind” the catalyst and reduce control efficiency. Disposal of the spent catalyst that is a potential hazardous waste also poses an environmental impact approximately every year.

C) **<u>Energy Impact</u>** – Although not detailed, there is typically an adverse energy penalty associated with overcoming the pressure drop across the catalyst bed.

According to RBLC, the most stringent control option for CO is 0.10 MMBtu, achieved with an RCO. Detroit Stoker, boiler manufacturer, states that GCP design can achieve a CO level of 0.25 lb/MMBtu, which is the lowest level achievable without a significant increase in NO_x emissions. There is only one facility in the RBLC (ref. Table 4-14 of the application) that had a limit less than 0.25 lb/MMBtu. All the boilers in the RBLC cite GCP as the control technology.

Therefore, DAQ selects GCP as BACT for CO emissions with an emission limit of 0.25 lb/MMBtu for the power boiler. Accordingly, the following additional emission limits are proposed for CO at 60 to 90 percent and 40 to 60 percent loads when firing wood: 0.30 lb/MMBtu and 0.40 lb/MMBtu, respectively. It should be noted that at reduced loads, CO emissions increase slightly due to less efficient combustion. This phenomenon is common across multiple types of boilers and can be even more pronounced when burning fuels with moisture like wood. **Also, DAQ selects GCP as BACT for VOC emissions with an emission limit of 0.017 pounds per million Btu heat input for the power boiler. Compliance with the CO limit will be determined utilizing a CEMS over a 30 day average.**

b. **<u>BACT for the Emergency Generator and Emergency Fire Water Pump Engine</u>** – The proposed emergency generator and emergency fire water pump engine are sources of CO and VOC. CO and VOC are emitted from these combustion sources as a function of the fuel being burned. The emergency generator will be limited to 500 hours per year. The firewater pump will be used a maximum of 100 hours per year for readiness testing. Add-on controls are impractical given the intermittent operation of these sources. BACT is proposed to be (3.5 g/kW-hr for CO and 4.0 g/kW-hr for VOC that is combined with NO_x) the same as the NSPS Subpart IIII standard as discussed in Section III. B. above.

3. **<u>BACT Analysis for Particulate Matter (PM), Particulate Matter less than 10 micrometers in diameter (PM_{10}), and Particulate Matter less than 2.5 micrometers in diameter ($PM_{2.5}$) emissions</u> -** Particulate emissions are the result of incomplete combustion and trace particulates and impurities in the fuel. Particulate emissions may have adverse health effects, reduce visibility, and contribute to environmental and aestetic damage. Particulates of particle size less than 10 micrometers in diameter have been linked to respiratory irritation, aggravated asthma, chronic bronchitis, decreased lung function, irregular heartbeat, nonfatal heart attacks, and premature death. Fine particles less than 2.5 micrometers in diameter reduce visibility (haze).

a. <u>BACT for the Power Boiler</u>

i. The applicant evaluated the following **control technologies** for PM emissions:

I) <u>Baghouse</u> - 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. However, excessive caking will increase the pressure drop across the fabric filter and reduce its efficiency.

The particulate removal efficiency of fabric filters is dependent upon a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e.g., structure of fabric, fiber composition, and bag properties). Often a mechanical collector, such as a multicyclone, is used to remove larger particulate matter before the exhaust reaches the primary control device.

II) <u>Electrostatic Precipitator (ESP)</u> - ESPs remove particles from a 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. Often a mechanical collector, such as a multicyclone, is used to remove larger particulate matter before the exhaust reaches the primary control device.

Because the applicant selected the most effective control technology, an ESP (achieving the same emission rate as that achieved by a bagfilter), no further analysis is necessary.

BACT is proposed to be set at 0.02 lb/million Btu [3-hour average]. Compliance will be determined by periodic stack testing.

b. **BACT for the Emergency Generator and Emergency Fire Water Pump Engine** – The proposed emergency generator and emergency fire water pump engine are sources of PM_{10}/$PM_{2.5}$. Particulates are emitted from these combustion sources as a function of the fuel being burned. The emergency generator will be limited to 500 hours per year. The firewater pump will be used a maximum of 100 hours per year for readiness testing. Add-on controls are impractical given the intermittent operation of these sources. BACT is proposed to be (0.20 g/kW-hr) the same as the NSPS Subpart IIII standard as discussed in Section III. B. above.

c. **BACT for the Flyash Storage Silo** – The proposed flyash storage silo is a source of PM_{10}/$PM_{2.5}$. Particulate matter emissions from the flyash storage silo will be controlled by a fabric filter. Fabric filters are capable of achieving the lowest achievable emission rates of potentially applicable particulate matter control devices. Therefore, BACT is proposed to be an outlet grain loading factor of 0.01 grains per cubic foot.

d. **BACT for the Cooling Tower** - The proposed four-cell cooling tower is a source of PM_{10}/$PM_{2.5}$. Particulates are emitted from the escape of water droplets containing dissolved solids. A certain fraction of these droplets will be of a size range such that upon evaporation in the atmosphere, a resulting particle of PM_{10} could be liberated as an air emission. PM_{10} (all filterable) is controlled by drift eliminators, which limit the number and size distribution of liquid water droplets that escape the tower (called “drift”). BACT is proposed to be 0.0005% drift. This determination is consistent with similarly sized cooling towers.

4. **<u>BACT Analysis for Sulfur Dioxide (SO_2) emissions</u>** – SO_2 emissions are produced by the combustion of sulfur-containing fuels. Generally, all of the sulfur compounds contained in the fuels will oxidize to SO_2.

   a. **<u>BACT for the Power Boiler</u>**

      The combustion of wood results in 94 tons per year of SO_2. The applicant did evaluate both scrubbers and sorbent injection. In both cases the costs to control the 94 tons was excessive. In addition to the costs, with the scrubber technologies there are adverse environmental issues including wastewater and by-product disposal costs. The details of these analyses can be found in Section 4.2.3.1 in the application package. The NC DAQ is proposing a BACT limit of 0.025 lb of SO_2 per million BTU.

b. **<u>BACT for the Emergency Generator and Emergency Fire Water Pump Engine</u>** – The proposed emergency generator and emergency fire water pump engine are sources of SO_2. Sulfur dioxide is emitted from these combustion sources as a function of the fuel being burned. The emergency generator will be limited to 500 hours per year. The firewater pump will be used a maximum of 100 hours per year for readiness testing. Add-on controls are impractical given the intermittent operation of these sources. BACT is proposed to be the same as the NSPS Subpart IIII standard as discussed in Section III. B. above. NSPS Subpart IIII requires the sulfur to be limited to maximum of 15 ppmw beginning October 1, 2010. Therefore, NC DAQ proposes BACT to be 15 ppmw sulfur fuel.

B. Prevention of Significant Deterioration (PSD) Air Dispersion Modeling Analysis

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 Nonattainment Area Permitting which will herein be referred to as the NSR Workshop Manual.

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

1. Significant Emission Rate (SER) Analysis

A facility-wide pollutant netting analysis was accomplished and documented in Table 3-1 of the Hertford Renewable Energy (HRE) analysis report. Five pollutants were declared to exceed their PSD Significant Emission Rate (SER) and thus require a PSD analysis. These emission rates are provided in the table below.

Table 1 - Pollutant Netting Analysis

Pollutant	Annual Emission Rate tons/yr	Significant Emission Rate tons/yr
NO_x	**377.37**	40
PM_{10}	**139.92**	15
SO_2	**93.98**	40
CO	**941.03**	100
VOC’s	**63.95**	40

2. Preliminary Impact Air Quality Modeling Analysis

An air quality preliminary impact analysis was conducted for the pollutants exceeding the corresponding SER. The modeling results were then compared to applicable Significant Impact Levels (SILs) as defined in the NSR Workshop Manual to determine if a full impact air quality analysis would be required for that pollutant.

The HRE facility will be located southwest of Ahoskie, NC, in Hertford County. The facility area is in the northern coastal plain with terrain being predominantly flat and is generally agricultural, industrial, and forestland. For modeling purposes, the area, including and surrounding the site, is classified rural, based on the land use type scheme established by Auer 1978.

HRE evaluated the pollutants' significant emissions using the EPA AERMOD model and five years (1988-1992) of National Weather Service (NWS) surface (Norfolk, VA) and upper air (Wallops Island, VA) meteorological data. Full terrain elevations were included, as were normal regulatory defaults. Sufficient receptors were placed in ambient air beginning at the fenceline to establish maximum impacts. Emission rates for this specific project were used and the maximum impacts were then compared to the SIL. Since the results showed an impact above both the annual and 24-hour SIL for PM_{10}, further modeling was required for PM_{10}. The Significant Impact Area established by the SIL modeling had a maximum radius of 0.8 kilometers. The SIL results are displayed in Table 2.

Table 2 - Class II Significant Impact Results (ug/m^3)

Pollutant	Averaging Period	Facility maximum Impact	Class II Significant Impact Level
PM_{10}	Annual	**1.01**	1
	24-hour	**6.51**	5
SO_2	Annual	0.21	1
	24-hour	4.19	5
	3-hour	8.25	25
CO	1-hour	1,900	2,000
	8-hour	475	500
NO_x	annual	0.87	1

3. Class II Area Full Impact Air Quality Modeling Analysis

A Class II Area NAAQS and PSD increment analysis was performed for PM_{10} to include offsite source emissions and background concentrations (NAAQS). HRE used AERMOD with the modeling methodology as described above. Off-site source inventories for both increment and NAAQS modeling were obtained from NC DAQ and then refined by HRE using the NC DAQ approved "Q/D=20" guideline. For the NAAQS analysis, one offsite source was used; no offsite sources were used for the increment analysis. This source, along with its emission rate, is provided as an attachment.

HRE used an appropriate array of receptors beginning at the declared fenceline and extending outward to 1.5 kilometers. PM_{10} background concentrations were taken from the Edgecombe County PM_{10} monitoring station. The modeling results are shown in Table 3 and indicate compliance with the NAAQS for PM_{10} for both averaging periods.

Table 3 - Class II Area NAAQS Modeling Results

Pollutant	Averaging Period	Maximum Onsite & Offsite Source Impacts (ug/m^3)	Background Concentration (ug/m3)	Total Impact (ug/m3)	NAAQS (ug/m3)	% NAAQS
PM_{10}	24-hour	11.40	11	22.40	150	15
	annual	1.07	9.3	10.37	100	21
$PM_{2.5}$	24-hour	11.40	21.1	32.5	35	93
	annual	1.07	9.99	11.06	15	74

In the CLASS II increment analysis, HRE used the same onsite sources, fenceline, and receptors as in the NAAQS analysis. The emission rates modeled are provided in the attachments. The Class II Area increment modeling results are shown in Table 4 and indicate compliance with the Class II Area increments.

Table 4 - Class II Area PSD Increment Modeling Results

Pollutant	Averaging Period	Maximum Onsite & Offsite Source Impacts (ug/m^3)	PSD Increment (ug/m3)	% Increment
PM_{10}	annual	5.21	17	31
	24-hour	1.01	30	3

Non Regulated Pollutant Impact Analysis (North Carolina Toxics)

HRE also modeled TSP and ammonia using AERMOD with the same receptor array and meteorology as used in the NAAQS analysis. A list of the facility sources and emission rates used are attached to this document. Both pollutants demonstrated compliance on a source-by-source basis with the NC's AAQS or Acceptable Ambient Level (AAL). The maximum concentrations, as shown in Table 5, occurred along the fenceline.

Table 5 - Toxics & SAAQS Modeling Results

Pollutant	Averaging Period	Max Facility Impact (ug/m3)	AAQS	AAL	Percent of AAL
TSP	annual	2.18	75	n/a	3
	24-hr	9.25	150	n/a	6
Ammonia	1-hour	2,564	n/a	2,700	95

4. Additional Impacts Analysis

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

<u>Growth Impacts</u>

HRE is expected to employ approximately 25 full-time people and this project is not expected to cause a significant increase in growth in the area.

<u>Soils and Vegetation</u>

The facility is located in the northern coastal plain of North Carolina. The local geography is flat with a mix of forests, agricultural crops, and herbaceous vegetation. By way of the NAAQS analyses of this submission, HRE demonstrated that the impacts were below the established standards – both the primary and secondary NAAQS. They contend that these standards are conservative and included considerations of impacts on soils and vegetation when they were established; NCDAQ agrees.

<u>CLASS II Visibility Impairment Analysis</u>

A Level 1 visibility impairment analysis was performed using the EPA VISCREEN model to demonstrate screening criteria were not exceeded in any CLASS II areas that are designated as special visibility protection areas. With background visibility set to 80km, the facility determined that screening visibility parameters were exceeded out to a distance of 85 km. Within that radius, there are no special protected visibility areas, thus no further visibility analysis was required.

5. Class I Area - Additional Requirements

The closest Class 1 area to the facility site is Swanquarter National Wildlife Refuge (NWR) which is about 114 km to the southeast of the facility. The Federal Land Manager for Swanquarter did not require any analysis; therefore, the no analysis was conducted by the applicant.

CLASS 1 SIL Analysis

AERMOD was also used to estimate impacts for the Class 1 SIL analysis. Even though the distance to Swanquarter NWR exceeds 50 km, the threshold distance at which a long-range transport model is typically used, receptors were conservatively placed at 50 km from the Hertford facility. All three pollutants, SO_2, NOx, and PM_{10} modeled below the EPA-established, CLASS 1 SILs, and thus no CLASS 1 increment modeling was required. Table 6 provides the results of SIL modeling.

Table 6 - Class 1 Significant Impact Results (ug/m^3)

Pollutant	Averaging Period	Max. Impact at 50 km	EPA SIL	% SIL
SO_2	3-hr	0.147	1	15
	24-hr	0.034	0.2	17
	Annual	0.002	0.08	2
NO_x	Annual	0.007	0.1	7
PM_{10}	24-hr	0.051	0.32	16
	Annual	0.003	0.16	2

6. PSD Air Quality Modeling Result Summary

Based on the PSD air quality ambient impact analysis performed, the proposed HRE project will not cause or contribute to any violation of the Class 1I NAAQS, PSD increments, Class 1 Increments, or any FLM AQRVs. A summary of the modeling results is presented in Table 7.

Note: Tables follow below.

TABLE 7 – HRE PSD AIR QUALITY MODELING RESULTS

SER Evaluation

Pollutant	Annual E/R (Tons)	SER (Tons/yr)					
NO_x	**377.37**	40					
PM_{10}	**139.92**	15					
SO_2	**93.98**	40					
CO	**941.03**	100					
VOC's	**63.95**	40					

Class II Area SIL Analysis

Pollutant	Averaging Period	Maximum Impact (ug/m^3)	SIL (ug/m^3)	SIL Exceeded			
PM_{10}	Annual	**1.01**	1	Yes			
	24-hour	**6.51**	5	Yes			
SO_2	Annual	0.21	1	No			
	24-hour	4.19	5	No			
	3-hour	8.25	25	No			
CO	1-hour	1,900	2,000	No			
	8-hour	475	500	No			
NO_x	annual	0.87	1	No			

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**
PM_{10}	24-hour	11.40	11	22.40	150	15
	annual	1.07	9.3	10.37	100	21
$PM_{2.5}$	24-hour	11.40	21.1	32.5	35	93
	annual	1.07	9.99	11.06	15	74

Class II Increment Analysis						
Pollutant	**Averaging Period**	**Maximum Onsite & Offsite Source Impacts (ug/m^3)**	**PSD Increment (ug/m3)**	**% Increment**		
PM_{10}	24-hour	5.21	17	31		
	annual	1.01	30	3		

Class I Area SIL Analysis							
Pollutant	**Averaging Period**	**Maximum Impact (ug/m^3)**	**SIL (ug/m^3)**	**SIL Exceeded**			
SO_2	3-hr	0.147	1	No			
	24-hr	0.034	0.2	No			
	Annual	0.002	0.08	No			
NO_x	Annual	0.007	0.1	No			
PM_{10}	24-hr	0.051	0.32	No			
	Annual	0.003	0.16	No			

N.C. SAAQS Analysis							
Pollutant	**Averaging Period**	**Maximum Facility Impact (ug/m^3)**	**SAAQS (ug/m^3)**	**% SAAQS**			
TSP	Annual	2.18	75	3			
	24-hour	9.25	150	6			

N.C. Toxics Analysis							
Pollutant	**Averaging Period**	**Maximum Facility Impact (ug/m^3)**	**AAL (ug/m^3)**	**% AAL**			
Ammonia	1-hour	2,564	2,700	95			

TABLE 5-3
MODELED FACILITY EMISSIONS
HERTFORD RENEWABLE ENERGY (HRE) POWER PLANT

Model ID	Source Description	TSP (g/s)	PM_{10} (g/s)	NO_2 (g/s)	SO_2 (g/s)	CO - 50% (g/s)	CO - 100% (g/s)
CLT1A	Cooling Tower	1.37E-02	5.48E-03	--	--	--	--
CLT1B	Cooling Tower	1.37E-02	5.48E-03	--	--	--	--
CLT1C	Cooling Tower	1.37E-02	5.48E-03	--	--	--	--
CLT1D	Cooling Tower	1.37E-02	5.48E-03	--	--	--	--
BLR1[2]	ESP Boiler 1	4.00E+00	4.001E+00	10.81	2.703E+00	21.63	27.03
EMER	250 kw Generator	1.85E-02	1.85E-02	2.11E-02	5.17E-04	0.32	0.32
FWPUMP[3]	400 hp fire pump	1.38E-03	1.38E-03	3.78E-03	1.99E-04	0.29	0.29
FLYASH	Flyash Storage Silo	3.53E-06	3.53E-06	--	--	--	--
SSILO1	Sorbent Silo 1	5.40E-04	5.40E-04	--	--	--	--

[1] PM_{10} and TSP emissions are equal for this analysis except that PM_{10} is only 40% of TSP for the cooling towers.

[2] CO Emissions based on 50% and 100% boiler loads

[3] Fire water pump will operate for 2 hours per week for roughly 52 weeks a year for a total of 100 hours per year. The NO_x modeled lb/hr rate is based on the ton per year rate. PM_{10} hourly rates are based on the lb/hr rate * 1/12 because it will only operate 2 hours per day.

TABLE 5-1
MODELED SOURCE LIST
HERTFORD RENEWABLE ENERGY (HRE) POWER PLANT

Model ID	Source Description	UTM Coordinates East (m)	UTM Coordinates North (m)	Elevation (m)	Stack Discharge (V / H)	Stack Height (m)	Exit Temp. (K)	Exit Velocity (m/s)	Diameter (m)
CLT1A	Cooling Tower	313,809.4	4,013,683.0	18.8	V	13.7	298.2	2.1	7.9
CLT1B	Cooling Tower	313,819.7	4,013,681.9	18.7	V	13.7	298.2	2.1	7.9
CLT1C	Cooling Tower	313,832.8	4,013,681.2	18.6	V	13.7	298.2	2.1	7.9
CLT1D	Cooling Tower	313,845.0	4,013,680.9	18.5	V	13.7	298.2	2.1	7.9
BLR1[1]	ESP Boiler 1	313,895.6	4,013,642.6	18.0	V	54.9	435.9/403.7	15.07/7.54	3.7
EMER	250 kw Generator	313,859.9	4,013,613.8	18.3	H	9.1	727.6	0.01	0.2
FWPUMP	400 hp fire pump	313,830.5	4,013,659.4	18.6	V	9.1	727.6	32.3	0.2
FLYASH	Flyash Storage Silo	313,849.5	4,013,609.2	18.4	H	27.7	298.2	0.01	0.6
SILO1	Sorbent Silo 1	313,905.6	4,013,606.0	19.0	H	9.6	298.2	0.01	0.30

[1] For CO, the 50% boiler load scenario was the worst case, however DAQ guidance suggested the 100% boiler load scenario be run as well. Thus, the temperature and velocity for the CO runs are both the 100% and 50% parameters respectively.

TABLE 5-9
TSP AND TAP RESULTS
HERTFORD RENEWABLE ENERGY (HRE) POWER PLANT

Pollutant	Averaging Period	Year	UTM-E (m)	UTM-N (m)	Modeled Impact (µg/m3)	SAAQS/ AAL (µg/m3)	Percent of Standard
TSP	Annual	1990	313.84	4,013.71	2.18	75	3%
	24-hour	1991	313.84	4,013.71	9.25	150	6%
Ammonia	1-hour	1992	NA	NA	2,565	2,700	95%

Note: The 1st High Concentration is conservatively shown for the 24-Hour TSP Analysis
Note: Ammonia compliance based on SCREEN3 modeling results. Maximum impacts are predicted in the cavity. A unit emission rate (1 g/s) was modeled and allowable emission rate (i.e., the rate producing 95% of the AAL) of 195.93 lb/hr was determined based on the modeled impact.

OFFSITE NAAQS AND INCREMENT SOURCES FOR HERTFORD MODELING

PM10 NAAQS Sources

	Model ID	Source Description	Source Type	UTM Coordinates East (m)	UTM Coordinates North (m)	Elevation[1] (m)	Emission Rate (g/s)	Stack Discharge (V / H)	Stack Height (m)	Exit Temp (K)	Exit Velocity (m/s)	Diameter (m)
NC	GPC1	Golden Peanut Company	Point	309589	4010658	7.62	5.84E-01	V	6.1	294.3	6.1	0.6

[1] GPC1 elevation from Google Earth

V. Facility Wide Regulations

There are two facility wide regulations that are applicable to this proposed request:

1) 2D .0540 "Fugitive Dust Emission Sources"

The Permittee shall not cause or allow fugitive dust emissions to cause or contribute to substantive complaints or excess visible emissions beyond the property boundary. If substantive complaints or excessive fugitive dust emissions from the facility are observed beyond the property boundaries for six minutes in any one hour (using Reference Method 22 in 40 CFR, Appendix A), the owner or operator may be required to submit a fugitive dust plan as described in 2D .0540(f).

2) 2Q .0700 "Toxic Air Pollutant Procedures" and 2D .1100 "Control of Toxic Air Pollutants"

The proposed power boiler operation will result in deminimis increases in several TAPs listed in 2Q .0711. Since the power boiler is a combustion source that will only burn unadulterated fuel (wood or biodiesel), the facility is exempt from the TAP rule pursuant to 2Q .0702(a)(18). However, the facility proposes to utilize SNCR as a control device for the power boiler that will result in "ammonia slip" from the unreacted ammonia. The ammonia emissions will be much greater than then deminimis level of 0.68 pounds per hour in 2Q .0711; therefore, the Permittee has requested that the ammonia emissions be modeled to 95% of the acceptable ambient level (AAL) listed in 2D .1104 to maximize operating flexibility. Mr. Tom Anderson with NC DAQ's AQAB reviewed and approved the dispersion modeling analysis for ammonia (ref. Modeling Analysis Memo dated June 23, 2009).

VI. Permit Stipulations

The proposed permit includes stipulations necessary for compliance with all applicable requirements.

VII. Other

Public Notice Requirements – 40 CFR 51.166(q) requires that the permitting agency make available to the public a preliminary determination on the proposed project, including all materials considered in making this determination. With respect to this preliminary determination the NC DAQ:

i) Will make available in the Hertford County Public Library all materials submitted, a copy of the preliminary determination, and all other information submitted and considered. In addition a copy of this same information will be available at the NC DAQ Washington Regional Office and the NC DAQ Central Office in Raleigh, NC.

ii) Will publish a public notice, by advertisement in a local paper including the preliminary decision and the opportunity for public comment.

iii) Send a copy of the public notice to:
  a. The applicant
  b. EPA Region IV for comment
  c. Officials having cognizance over the location of the location of the project as follows:
     i. Any affected state/local air agency – No other state or local agencies are expected to be affected by this project.
     ii. Chief Executives of the city/town and county in which the proposed project is to be located. Notices will be sent to the County Manager for Hertford County.
     iii. Federal Land Manager – As noted above, the FLM for the closest Class I area did not request any analysis to be performed.

VIII. Conclusion

Based on the application submitted and the review of this proposal by the NC DAQ, the NC DAQ is making a preliminary determination that the project can be approved and a permit issued. A final determination will be made following public notice and comment and consideration of all comments.