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May 27, 2010

Thomas S. Burack, Chairman
Site Evaluation Committee
N.H. Department of Environmental Services
29 Hazen Drive
Concord, NH 03302

Re: Laidlaw Berlin BioPower, LLC – SEC Docket No. 2009-02
Application Amendment Pertaining to Air Permit

Dear Chairman Burack:

Laidlaw Berlin BioPower's consultants have been working closely with the New Hampshire Air Resources Division regarding the Air Permit portion of the LBB Application for a Certificate of Site and Facility. Based on those discussions, and at the request of the Air Resources Division, we have revised the Air Permit Application. The enclosed materials have been provided to ARD. We request that they now be included as an Amendment to the Certificate Application. As noted in the cover letter to the Air Resources Division, these changes will result in reductions in the proposed emission rates for particulate matter, nitrogen oxides and sulfur dioxide.

In addition, we have also included specific pages of the Certificate Application that should be amended as well. We have provided clean and redline copies.

If you have any questions, please feel free to contact me.

Sincerely,

Barry Needleman

Enclosure

STATE AIR PERMIT APPLICATION

BERLIN BIOPOWER, LLC
57 HUTCHINS STREET
BERLIN, NEW HAMPSHIRE

PREPARED FOR: Laidlaw Berlin BioPower, LLC
90 John Street, 4th Floor
New York, NY 10038

PREPARED BY: ESS Group, Inc.
888 Worcester Street, Suite 240
Wellesley, Massachusetts 02482

Project No. L145-005.01

December 15, 2009
Revised May 18, 2010

STATE AIR PERMIT APPLICATION
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ESS Group, Inc.

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ESS Group, Inc.

1.0 INTRODUCTION

Laidlaw Berlin BioPower, LLC (LBB) is proposing to convert and upgrade the existing facility equipment and infrastructure located at the former Fraser Pulp Mill in Berlin, New Hampshire in order to develop a biomass fueled energy generating facility. Berlin BioPower (the Facility or Project) will use whole tree wood chips and other low-grade clean wood as fuel, and will be capable of generating nominally 70 megawatts (MW) of electric power (gross output), making it one of the largest biomass-energy facilities in the United States. The Facility will provide a source of clean, carbon-neutral, renewable energy that will help support New Hampshire's goal of meeting 25% of the state's energy needs with renewable resources by 2025. The Facility's use of biomass fuel will also help reduce reliance on fossil fuels such as oil and natural gas that are in ever decreasing supply, and will provide a beneficial use of waste wood material.

The Facility will include a boiler, which will be a stationary source using wood as fuel, with a design rating greater than 2 million British thermal units (MMBtu) per hour of gross heat input. Therefore, in accordance with the New Hampshire Code of Administrative Rules (NHCAR), Chapter Env-A 600, a temporary permit is required prior to the construction of the Facility. The Facility will also be required to comply with the applicable requirements of the NHDES Air Pollution Control Regulations (NHCAR Chapters Env-A 100-4800).

The Facility will be a major stationary source of nitrogen oxides (NO_X) emissions, with potential emissions greater than 100 tons per year. Coos County is designated as being in attainment for ozone, however is within the New Hampshire portion of the Northeast Ozone Transport Region. The Facility will therefore be subject to state nonattainment review (NHCAR Part Env-A 618), which requires the implementation of the lowest achievable emission rate (LAER), and offsets for its NO_X emissions.

As a major stationary source located in an attainment area, the Facility will also be subject to the applicable Prevention of Significant (PSD) of Air Quality permit requirements. The NHDES has implemented the federal PSD Program permitting requirements (NHCAR Part Env-A 619) to determine if a new major stationary source will cause or contribute to significant deterioration of air quality in the state. The PSD requirements include the completion of an air dispersion modeling analysis to demonstrate that the Project will not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS), and that the maximum increases in pollutant concentrations over the existing baseline do not exceed the allowable PSD increments. The PSD program requires the implementation of Best Available Control Technology (BACT) for each regulated new source review (NSR) pollutant with potential emissions above the significance thresholds. The PSD program also requires specified additional impact analyses including an analysis of ambient air quality in the area the source would affect, and an analysis of other impacts that would occur as a result of the source and general commercial, residential, industrial, and other growth associated with the source, including potential impacts on Class I areas.

The Facility must also comply with the applicable subparts of the federal New Source Performance Standards (NSPS), and the National Emission Standards for Hazardous Air Pollutants (NESHAPS), which requires the application of Maximum Available Control Technology (MACT) for sources located at a facility which is a major source of HAP emissions.

This document provides all of the materials and supporting information necessary to comprise a complete application for a temporary permit for the construction of the Facility. Section 2 provides a complete description of the proposed Facility. Section 3 presents a discussion of the potential air emissions from the Facility along with the measures that will be used to minimize emissions and air quality impacts. Section 4 provides a discussion of the state and federal air regulations that apply to the Facility and how it will comply with those requirements. The BACT/LAER analyses conducted for the Facility are detailed in Section 5. The case-by-case MACT determination for the Facility is detailed in Section 6. The dispersion modeling analysis conducted for the Facility is summarized in Section 7. The additional impact analyses conducted to satisfy the PSD requirements for the Facility are also detailed in Section 7. The required completed permit application forms are included in Section 8. All necessary supporting materials are provided in the figures, tables, and appendices incorporated into this application document.

2.0 FACILITY DESCRIPTION

The Facility will be a base loaded electric generating facility with a nominal gross electrical output of 70 MW. The heart of the Facility will be a bubbling fluidized bed (BFB) boiler; highly advanced technology considered state-of-the-art for maximum energy conversion of biomass fuel to power generation. The development of the Facility will include construction of a new turbine building adjacent to the boiler building, which will house the steam turbine generator. A new wet cooling tower will be installed near the western edge of the property behind the boiler building. Two wood fuel off-loading and storage areas will be developed. The Facility will also include a diesel fire pump with a maximum rating of 323 HP.

Figure 1 is a United States Geologic Survey (U.S.G.S.) Map showing the location for the proposed Facility. A proposed site plan, which shows the property line of the Facility, and the location of all buildings and structures, has been included as Figure 2. Figure 3 shows the dimensions of the structures on the Site. Visual simulations of the proposed Facility have been provided in Appendix B. The following sections describe the components of the proposed Facility.

2.1 Biomass Boiler & Steam Generator

The existing B&W recovery boiler will be converted to a biomass fired bubbling fluidized bed (BFP) boiler with open hopper bottoms for removal of fuel ash, bed sand particles and other non-combustible materials. An air distribution system consisting of fluidizing air and overfire air will be used to assure efficient fuel combustion. A flue gas recirculation system will be utilized to cool the bed when required. The existing feedwater economizer, which will preheat the feedwater to the boiler drum, will be modified to optimize boiler efficiency. The boiler feedwater will be treated with sodium sulfite after the deaerator, as recommended by the boiler manufacturer. The use of a tubular air pre-heater will insure maximum use of the energy release in the boiler.

The boiler will be capable of generating up to 600,000 pounds per hour of steam at 825°F and 850 psig. The boiler will be capable of maintaining stable operation and compliant emission levels from 70% to 100% of its maximum steam output. A series of double sided retractable soot blowers will be utilized on heat transfer surfaces within the superheater and convective sections of the boiler to maintain design performance levels.

The boiler will be capable of firing whole tree chips at a minimum moisture content of 35% and a design moisture content of up to 50%. At an average moisture content of 37.6%, the wood fuel will have a higher heating value of approximately 5,060 Btu/lb. The heat input rate to the boiler will vary depending on the moisture content of the wood fuel. The average heat input rate at maximum steam load will be 932 MMBtu/hr with 37.6% moisture content fuel. The maximum heat input rate will be 1,013 MMBtu/hr with 50% moisture content fuel. Individual fuel feeders will be equipped with adjustable air swept distributors to adjust the flow of fuel into the boiler. The fuel chutes will each be equipped with backdraft dampers.

The boiler will also be equipped with four No. 2 distillate oil fired burners for use during startup. Each of the oil burners will have a maximum heat input capacity of 60 MMBtu/hr. The oil burners will be fired with Ultra Low Sulfur Diesel (ULSD) fuel with a high heating value of approximately 18,698 Btu/lb. The emergency diesel fire pump will also be fired with ULSD.

ULSD fuel for the boiler startup burners and the fire pump will be stored on-site in a 50,000 gallon storage tank equipped with secondary containment. An existing oil storage tank will be used by removing the roof and erecting a new tank inside to achieve a double wall storage design. The ULSD storage tank will be registered and LBB will meet all of the applicable state design, inspection, maintenance, testing, and reporting requirements for its use.

The steam turbine generator will be designed for a steam inlet pressure of 850 psig and a steam inlet temperature of 900°F. The maximum capacity of the steam turbine generator will be 66 MW.

2.2 Wood Handling System

The Facility will employ a wood handling system to provide adequate wood chip fuel to operate the boiler continuously, along with approximately 30 days of fuel storage (15 days processed, 15 days unprocessed) available on-site at all times. Round wood and wood chips will be transported to the Facility via trucks and weighed before dumping. Round wood will be unloaded and stored in dedicated storage areas, before being chipped on-site and conveyed to the unprocessed fuel pile. The wood chips transported to the site by truck will be unloaded directly into the unprocessed fuel pile using three truck dumpers.

An on-site round wood chipping facility will consist of a purpose built structure to contain log milling equipment that will reduce round wood logs to chips suitable for boiler fuel. Logs will be delivered and unloaded in the round wood storage area located to the northeast of the power facility. From there they will be loaded by crane arm and grapple and fed lengthwise and horizontally into the chipping building by conveyor. Inside the building, an electric motor driven chipper will reduce the logs to fuel size chips. The wood chips will then be conveyed from the chipping facility to the processed wood chip fuel storage area adjacent to the power plant.

The wood in the unprocessed fuel pile will be manually loaded into hoppers to be conveyed to the fuel processing building. Wood processing will include a magnet, disc screen, and grinders (hogs). Wood will be processed and stocked out using a single train equipped with two hogs. The processed wood will be stacked out by a conveying system, reclaimed, and screened before being conveyed to the boiler using individual feeders.

The weigh station will consist of two 60 ton weigh scales and a scale house. Each of the three truck dumpers will have a capacity of 60 tons and will be capable of unloading approximately five trucks, or 150 tons of wood per hour. The dumpers will be capable of tilt-up of 63 degrees from horizontal and will dump to grade.

The unprocessed fuel storage pile will be open and on paved ground with an under drain system to remove rain water from the storage area. The paved pile area will have a perimeter drain system. Two reclaim hoppers will be used for the manual reclaiming of fuel from the unprocessed fuel storage area. Each hopper will discharge to a common 250 ton per hour unprocessed fuel out-feed conveyer, which will supply the fuel processing system.

A magnet will be installed over the truck dumper outfeed conveyer near the processing building. A disc screen capable of processing 250 tons per hour will be used to screen the unprocessed wood for boiler fuel. Two wood hogs will be used to reduce the wood fuel from the disc screen to a three inch minus size. Each hog will be capable of processing up to 75 tons per hour of wood fuel.

A 250 ton per hour stockout conveyer will receive the discharge from the processing building and convey it to the processed wood fuel storage area. The processed wood fuel storage area will be open and on paved ground with an under drain system to remove rain water from the storage area. The paved pile area will have a perimeter drain system.

Three 50 ton per hour reclaimers located under the storage area will supply a single boiler feed conveyer. The boiler feed conveyer will feed the shuttle conveyers which will distribute fuel to individual boiler chutes. A single return conveyer will return excess fuel to the wood storage area. Each fuel metering bin will be equipped with screw feeders to meter wood fuel to the boiler feed chutes. There will be one inverted cone type chute connecting each pneumatic distributor on the boiler with a set of feeders at the metering bin.

2.3 Ash Handling Systems

The ash handling facilities will consist of separate collection and storage systems for fly ash and for bed sand removal, screening and re-injection.

Fly ash will be continuously collected from the fabric filter (baghouse) particulate emissions control system using a dry mechanical system. Collected fly ash will be conveyed to a dry storage bin inside of the boiler building. The storage capacity will be sufficient to accept fly ash generated over a minimum period of twenty four hours of full-load operation. There will be an atmospheric vent on the ash silo equipped with a filter to minimize fugitive emissions. Ash from the elevated storage bin will be processed through a pug mill which mixes dry ash with water to produce a wet cake that minimizes dust generation during subsequent handling. The wetted fly ash will then be loaded onto trucks and transported off-site for beneficial re-use in agricultural land applications (in accordance with NHCAR Chapter Env-Sw 1700) or for disposal. LBB has confirmed that the ash can be accepted and disposed at the nearby Mount Carberry Landfill if it is not acceptable for beneficial re-use.

Bottom ash is greatly minimized by the high fuel conversion efficiency of the bubbling fluidized bed boiler design. Fuel is continually recirculated within the fluidized bed until fully combusted. A small stream of sand from the bed is continually withdrawn, screened and returned to the boiler, along with additional make-up sand as required. A small amount of noncombustible material such as rock, slag, glass or metal, is screened out of the bed material and collected for periodic disposal. The sand silo will be located within the boiler building and will have an atmospheric vent equipped with a filter to minimize fugitive emissions.

2.4 Water Systems

The power generation process will utilize two recirculating water systems; a steam generation system and a cooling water system. In the steam generation cycle, feedwater will be pumped through heat exchangers that will recover heat from downstream operations and into the boiler. The water will be circulated through metal tubes within the boiler where it will be converted to superheated steam. The steam will then used to power a turbine which will mechanically drive an electric generator. After leaving the turbine, the steam will be cooled back to the liquid state in a condenser and returned to the feedwater pumps. In order to prevent the build up of contaminants in the recirculating steam system, a small fraction of the water will be "blown down" to the wastewater system.

The cooling water cycle will pump water to the steam condenser to remove heat and return the steam to water. The heated cooling water leaving the condenser will be delivered to a wet cooling tower. In the cooling tower, the water will be sprayed over the top of packing material and will pass down through counterflowing ambient air drawn through the tower by large fans mounted in the top of the unit. The water will be cooled by both heat transfer and evaporation as it passes through the tower in an induced air stream. The exhaust system of the cooling tower will be equipped with mesh drift eliminators that will control entrained water droplets to less than 0.0005% of the recirculating water flow. The cooled water leaving the tower will be returned to the steam condenser system. Similar to the steam cycle, a portion of the recirculating water will be blow down to the wastewater discharge system to prevent the accumulation of contaminants.

The water for the Facility will be provided by the Berlin Water Works municipal supply and distribution system. The Facility will require up to 1.8 million gallons per day of water, primarily for cooling tower make-up, with the balance used to produce demineralized make-up water for the boiler, for human consumption, sanitary uses, and for other miscellaneous uses. A trailer mounted water treatment system will be used to provide demineralized water to be used for steam cycle makeup for the boiler. A 15,000 gallon demineralized water tank will be used for on-site storage.

Sanitary drains will collect and route the wastewater from potable uses to the city sewer system. Water treatment for the boiler make-up water will consist of reverse osmosis and a treatment program consisting of phosphate, caustic, neutralizing amine and oxygen scavenger for water used in the closed loop steam system. The cooling water treatment program for the cooling tower makeup water will consist of corrosion inhibitor, dispersant and biocides to prevent biological growth in the cooling system components. All process wastewater, including water collected in floor drains from equipment cleaning, will be discharged to the city sewer system. The Facility will discharge up to 300,000 gallons per day of sanitary and process wastewater to the municipal sewer system. It is not expected that the Facility wastewater will require any pretreatment to meet all applicable state and city discharge requirements.

The primary source of water for fire protection will also be city water. A motor-driven fire pump will be used at the Facility, with a diesel fire pump as a backup system. The entire wood storage area and power block will be served by an underground hydrant system. A wet standpipe system will be installed in all heated buildings. Unheated buildings and wood conveyers will be served by a dry standpipe with sprinklers. Portable hand extinguishers will be located throughout the Facility. Office areas will be equipped with wet pipe sprinkler systems. The steam turbine generator, lube oil tank area and the main transformer will be served with dry pipe, open spray deluge systems. All fire detection and alarm systems will be installed to meet their respective NFPA codes.

2.5 Air Pollution Control Systems

The BFB technology used in the boiler's combustion system represents state-of-the-art in efficient fuel conversion and emissions minimization. By maximizing combustion efficiency, the BFB technology generates vastly lower emissions of pollutants resulting from incomplete combustion such as carbon monoxide (CO) and volatile organic compounds (VOC). The combustion system also incorporates flue gas recirculation (FGR), a technology that cools the combustion process and reduces the formation of NO_X.

In addition to the inherently low emitting technology of the combustion system, the Facility will incorporate a number of additional systems that represent BACT and LAER technology to further minimize air emissions.

A dry sorbent injection system will be installed to introduce limestone or Trona into the exhaust gas stream. The sorbent will react with gases such as sulfur dioxide, sulfuric acid mist, and hydrochloric acid contained in the boiler exhaust to reduce those emissions and form particulate sulfates or chlorides, which will be minimized by the downstream particulate emissions control system.

The existing ESP will be replaced with a fabric filter baghouse system to maximize control of particulate emissions and meet the BACT emission limits. The baghouse will provide greater than 99% control of PM emissions.

A selective catalytic reduction (SCR) system will be installed downstream of the ESP for the control NO_X emissions. The SCR system will utilize aqueous ammonia (NH_3) that will be injected into the flue gas in a stoichiometric ratio proportional to the mass of NO_X to be removed. The aqueous NH_3 will evaporate in the inlet header. The flue gas and NH_3 will then pass through two beds of catalyst where the NO_X in the flue gas will be converted into nitrogen and water. An ammonia injection control system will be installed to accurately inject the correct amount of ammonia into the flue gas stream upstream of the catalyst to provide optimum control and minimization of both NO_X and NH_3 and assure compliance with permit limits. The NH_3 for the SCR system will be stored on-site in 19% aqueous solution in a storage tank equipped with secondary containment. The NH_3 storage tank will include an unloading system to accept deliveries by truck.

The existing 320-foot tall, 11.25" diameter boiler exhaust stack will be used. A continuous emissions monitoring system (CEMS) will be installed on the boiler stack to monitor compliance with the permitted emission limits. The CEMS will monitor the concentrations of oxygen, CO and NO_X and will be certified to meet all applicable NSPS, Acid Rain Program, and NHDES requirements. A certified continuous opacity monitoring system (COMS) will also be installed on the boiler stack to monitor compliance with Facility opacity limits.

2.6 Electrical Interconnection

The Facility will generate electrical power for its own operation and export the excess generated power to the Public Service of New Hampshire (PSNH) 115 kV system. A small switchyard will be installed adjacent to the turbine building, which will provide necessary power isolation systems and a step up transformer to increase the voltage of the power produced by the steam turbine generator to 115 kVA, consistent with the PSNH transmission line. From the switchyard, an underground transmission cable will be installed along a route that follows existing underground pipes that were formerly used to transport pulp from the site to the Fraser Gorham paper mill. The route leaves the Site near the intersection of Coos and Community Streets and generally follows the route of the former rail line from the site to Shelby Street. The transmission cable will transition to an overhead line approximately 0.75 miles south of the Site and 0.1 miles northwest of the existing East Side substation. The overhead transmission line will be installed within the existing cleared corridor between Shelby Street and the substation.

3.0 FACILITY EMISSIONS

The Facility will be equipped with state-of-the-art emissions control systems to minimize air emissions and ambient air quality impacts. The Facility will comply with all applicable NH State Air Pollution Control Regulations. The Facility will implement LAER for its NO_X emissions, and BACT for all regulated NSR pollutants with potential emissions that exceed the significance levels defined in the PSD regulations. The emissions from the Facility will also comply with the applicable NSPS and NESHAP/MACT emission standards.

The maximum stack concentrations and emission rates proposed for each pollutant from each emissions source are summarized on Table 3.1. The biomass boiler maximum stack concentrations and emission rates do not apply at loads less than 70% of maximum load. The biomass boiler will not operate at steady-state at loads less than 70% of maximum load, except for during periods of startup and shutdown. The maximum short term (lb/hr) emission rates presented in Table 3.1 are derived from the maximum emission rates for each pollutant (lbs/MMBtu), the maximum heat input rate to the boiler (1,013 MMBtu/hr), and a 10% factor to account for expected short-term variability in the exhaust gas volumetric flow rate from the boiler.

The potential emissions from the Facility, including emissions occurring during startup periods, and fugitive emissions resulting from wood fuel storage and handling activities, are summarized on Table 3.2. The potential emissions for the biomass boiler presented in Table 3.2 are derived from the maximum emission rates for each pollutant (lbs/MMBtu) and the average annual heat input rate for the boiler (932 MMBtu/hr). The potential emissions calculations for each of the Facility's emission sources are included in Appendix A of the application.

3.1 Biomass Boiler Emissions

3.1.1 Nitrogen Oxides

Emissions of NO_X result from excess air in the high temperature regions of a boiler and oxidation of nitrogen in fuel. The Facility's boiler will utilize a bubbling fluidized bed that provides staged combustion of the wood fuel and minimizes thermal NO_x formation. To meet the requirements of the NH RPS program, the Facility will limit its wood biomass fuel to clean sources of wood, which can help minimize NO_X formation resulting from fuel-bound nitrogen. Good combustion practices and the use of a BFB combustion process will help optimize the combustion temperature in the boiler to minimize thermal NO_X formation. A highly efficient Selective Catalytic Reduction (SCR) system will eliminate over 70% of NO_X emissions formed within the boiler. The SCR system will inject vaporized aqueous NH_3 into the hot exhaust gas path which will react with the NOx in the exhaust gas to form nitrogen and water vapor as the exhaust gases pass through the catalyst beds. The use of the BFB technology, clean wood fuel, good combustion practices, and SCR will result in a NO_X emission rate from the biomass boiler no greater than 0.060 lb/MMBtu of heat input based on a 30-day rolling average during normal operation.

3.1.2 Carbon Monoxide

CO emissions are associated with incomplete combustion of fuel in a boiler. These emissions will be minimized by utilizing the highly efficient BFB combustion technology. The wood fuel will be combusted in a heated bed of sand-like material which is fluidized within a rising column of air. The hot bed material effectively liberates the carbon in the wood fuel, which allows the oxygen (O_2) in the combustion air to more freely react with the fuel, resulting in an efficient combustion process. The air to fuel ratio and combustion temperature in the boiler will be optimized and monitored to achieve the desired balance between CO and NO_X emissions. As mentioned earlier, the Facility also will utilize a fuel preparation system that will help optimize the quality, size and moisture content to promote efficient combustion, which will also help mitigate CO formation. The use of BFB combustion technology in the boiler design, good combustion practices, and fuel type will result in a CO emission rate from the biomass boiler no greater than 0.075 lb/MMBtu of heat input based on a 24-hour daily block average during normal operation.

3.1.3 Sulfur Dioxide/Sulfuric Acid Mist

Emissions of sulfur compounds result from oxidation of sulfur contained in a fuel. The Facility will utilize wood fuel which has inherently low sulfur content, in combination with a dry sorbent injection system on an as-needed basis, to maintain SO_2 no greater than 0.012 lb/MMBtu of heat input during normal operation. The characteristics of wood fly ash also serve to capture much of the sulfur compounds and further minimize emissions. Based on experience with other generating facilities using an SCR control system, no more 10% of the SO_2 generated in the boiler is expected to be further oxidized to SO_3, which will combine with water vapor in the flue gas to produce sulfuric acid mist (H_2SO_4). The resulting maximum potential H_2SO_4 emission rate, which does not consider the potential reductions of sulfuric acid mist that will be achieved when using the sorbent injection system, is expected to be less than 0.002 lbs/MMBtu of heat input.

3.1.4 Particulate Matter

Particulate matter is generated in a boiler by incomplete combustion and the non-combustible fraction of a fuel. The BFB combustion technology and operating controls provide a greater degree of complete combustion than most other wood fired boiler designs. The boiler's fabric filter baghouse will abate over 99 percent of the particulate emissions formed in the boiler. These measures will result in a filterable $PM/PM_{10}/PM_{2.5}$ emission rate no greater than 0.010 lb/MMBtu of heat input during normal operation.

3.1.5 Volatile Organic Compounds

Like CO, VOC emissions are formed by incomplete combustion of fuel. VOC emissions from the biomass boiler at the Facility will be minimized utilizing BFB combustion technology. The Facility will also utilize clean wood fuel, which can help promote efficient combustion, which will further minimize VOC emissions. The use of BFB combustion technology in the boiler design, good combustion practices, and woody biomass fuel will result in a VOC emission rate from the biomass boiler no greater than 0.010 lb/MMBtu of heat input during normal operation.

3.1.6 Ammonia

The SCR emissions control systems will utilize aqueous ammonia to reduce the NO_X emissions from the boiler by injecting this NH_3 into the flue gas stream upstream of an SCR catalyst. The NO_X and NH_3 will react to form nitrogen (N_2) and water (H_2O). While this system is efficient for the conversion of NOx emissions to form nitrogen and water, a small fraction of the injected NH_3 will pass through unreacted. This unreacted NH_3 is referred to as NH_3 slip. The SCR system to be utilized at the Facility will be designed to maintain a stack NH_3 slip concentration of no greater than 20 ppmvd@7%O_2 during normal operation.

3.1.7 Hazardous Air Pollutants

HAP emissions from the biomass boiler at the Facility will be controlled utilizing BFB technology. The Facility will also employ measures to provide a wood fuel to the boiler of good quality, size and moisture content to promote efficient combustion, which will further minimize HAP formation. The use of BFB combustion technology in the boiler design and good combustion practices will minimize the HAP emissions from the boiler during normal operation. HAP emissions will be further reduced through use of the sorbent injection system, installed primarily to control SO_2 emissions.

3.1.8 Carbon Dioxide

The use of biomass energy has the potential to greatly reduce greenhouse gas emissions in this biosphere over the life cycle of these technologies. Fossil fuels release carbon dioxide captured by photosynthesis millions of years ago — an essentially "new" greenhouse gas emission. Biomass, on the other hand, releases carbon dioxide that is, for the most part, already a part of the natural environment and is therefore balanced by the carbon dioxide captured in its own growth as well as new growth.

The direct firing of Biomass is recognized as carbon neutral by many of the world's energy experts. The National Renewable Energy Laboratory (NREL), as part of the US Department of Energy published a study in January 2004 entitled "Biomass Power and Conventional Fossil Systems with and without CO_2 Sequestration – Comparing the Energy Balance, Greenhouse Gas Emissions and Economics". The study was a comparison of the Global Warming Potential (GWP) of a standardized 600 MW power plant (or in the case of direct fired biomass, several smaller plants totaling 600 MW) to determine the effect on global warming over the complete life cycle of each process. The study included fossil fuel fired and biomass fired plants with and without carbon sequestration (recovery of CO_2 emissions). The study concluded that, for direct fired biomass plants without carbon sequestration, the total CO_2 emitted was actually a negative value when considering the avoided emissions from land-filling and mulching and the additional emissions of harvesting and transportation, of the same quantity of biomass. The GWP was a reduction of 148% when compared to a similar-sized coal fired power plant.

Similarly, the International Panel on Climate Change (IPCC) Task Force on National Greenhouse Gas Inventories published its "2006 IPCC Guidelines for National Greenhouse Gas Inventories".

The document recommends that the CO_2 emissions from the combustion of wood and paper waste for the purposes of producing energy be excluded from national inventories as "biogenic emissions". It further states that where both fossil-based wastes (e.g. plastic, waste oil, rubber) are fired with biogenic-based wastes (e.g. wood, paper,), only the fossil-based portion of the CO_2 emissions be considered in national CO_2 inventories.

There are no add-on control systems available to control CO_2 emissions from wood-fired boilers. The use of BFB combustion technology in the boiler design, however assures a high degree of heat transfer from the fuel, thus minimizing the quantity of CO_2 released per MW of power produced.

3.1.9 Emissions During Startup & Shutdown

During cold startups, a three phase process will be used. Initially, the biomass boiler will be operated on ULSD fuel over a period of six-to-eight hours until stable operating temperatures are achieved in the bed and boiler heat transfer surfaces. The next phase will be the gradual introduction of solid fuel and the reduction of fuel oil until the steaming rate is gradually increased to 50% over a two-to-three hour period and the fuel transitions to 100% biomass. The last phase is the gradual ramping up of steaming load from 50% to 70% capacity over a period of one-to-two hours. Therefore, a typical cold total startup period is expected to be approximately 10-12 hours in duration to achieve steady-state biomass operation. The durations of startup periods for hot and warm starts of the boiler will be shorter.

The potential emissions during startup periods have been estimated and are shown in Table 3.2, based on a total of 6 cold starts per year of the biomass boiler. These emissions estimates are conservative in that boiler startups will typically be warm or hot starts of shorter duration and fewer emissions. For the purposes of the potential emissions calculations, it has been assumed that up to 72 hours of annual boiler operation will be during startup periods. Emissions during shutdown periods have been aggregated with emissions during normal operation.

The Facility will conduct emissions testing to determine the actual emissions from the biomass boiler during startup and shutdown periods. Permitted emissions for such periods will be determined from the results of startup/shutdown emissions testing.

3.2 Other Stationary Emissions Sources

3.2.1 Cooling Tower

Wet cooling towers provide direct contact between the cooling water and the air stream being drawn through the tower. A portion of the cooling water can be entrained in the air stream. The water droplets entrained in the air stream is classified as drift, which results in particulate emissions from the solids contained in the droplets as the water evaporates. The quantity of the drift and resulting particulate emissions are primarily determined by the design and operation of the cooling tower.

The formation of drift and the resulting particulate emissions will be minimized by controlling the dissolved solids content of the recirculating water and controlling water droplet drift.

Drift eliminators are designed to remove the water droplets from the air stream before it exits the tower. The exhaust system of the Facility cooling tower will be equipped with mesh drift eliminators that will control entrained water droplets to less than 0.0005% of the recirculating water flow and minimize particulate emissions to maximum extent achievable for a wet cooling tower.

3.2.2 Diesel Firewater Pump

The Facility will also include a diesel engine driven fire pump with a maximum power output of 323 horsepower. The diesel fire pump will be fired with ULSD fuel to minimize SO_2 and PM emissions and will be certified to meet the applicable EPA Tier 3 emission standards for diesel engines. The diesel fire pump will be limited to 500 hours of operation per year, and other than one hour per day for maintenance and testing, will not be operated concurrently with the biomass boiler.

3.3 Fugitive Emissions

Fugitive dust emissions potentially resulting from truck traffic on Site roadways and from wood fuel storage and handling operations will be minimized through a number of Best Management Practices and equipment designs. These measures will include the use of paved roadways, regular sweeping of roadways, wetting of fuel storage piles as needed during prolonged dry periods, and the use of covered trucks and conveyor systems. Fugitive dust emissions from the Facility's wood fuel handling and storage areas have been estimated using EPA published emission factors.

4.0 REGULATORY FRAMEWORK

The United States Environmental Protection Agency (US EPA) and the NHDES have established several regulations to assure that emissions sources such as those associated with the Facility do not result in adverse impacts to human health or the environment. This section provides a discussion of the applicability of those regulations, a summary of the requirements imposed by the regulations that apply to the Facility, and a discussion of how the applicable requirements will be met.

4.1 State and Federal Permitting Requirements

4.1.1 State Air Permit

NHCAR Chapter Env-A 600 establishes the statewide permit system to regulate the operation and modification of new and existing stationary sources. It requires all stationary sources to possess a temporary permit, state permit to operate, or Title V operating permit prior to construction, installation, operation, or material modification of the source. NHCAR Env-A 700 establishes a fee system for the review and issuance of state permits. NHCAR Env-A 1700 states the information required for all applications for permits.

The Facility will include a boiler, which will be a stationary source using wood with a design rating greater than 2 MMBtu per hour of gross heat input. Therefore, in accordance with NHCAR Part Env-A 607, LBB is required to obtain a temporary permit prior to the construction of the Facility. The application to the NHDES, Air Resources Division, for the temporary permit, must include the required application forms and meet the applicable requirements of NHCAR Part Env-A 607.03 (temporary permit application requirements), Env-A 702.01 (temporary permit application review fees), and Env-A 1703 through Env-A 1709 (application forms).

The application must demonstrate compliance with all applicable elements of the State Implementation Plan (SIP). It also must demonstrate that the proposed Facility will not cause or contribute to an exceedance of the State Ambient Air Quality Standards (NHCAR Chapter Env-A 300) and will comply with applicable state law governing pollution, and all other Applicable requirements.

This application document satisfies the requirements for a temporary permit application. It includes the required completed application forms (Section 9), and addresses compliance with the applicable state and federal air permitting and pollution control requirements for the Facility (Section 4). It also includes an air dispersion analysis that demonstrates that the emissions from the Facility will not cause or contribute to an exceedance of state ambient air quality standards (Section 7).

The temporary permit for the Facility will expire 18 months after the date of its issuance. LBB will file an application for a Title V Operating Permit at least 90 days prior to the designated expiration date of the temporary permit. The Title V Operating Permit application for the Facility will meet all of the applicable requirements of NHCAR Part Env-A 609.

4.1.2 Nonattainment Review

The Facility will be a major stationary source of NO_X emissions, with potential emissions greater than 100 tons per year. Coos County is designated as being in attainment for ozone, however it is within the New Hampshire portion of the Northeast Ozone Transport Region. The Facility will therefore be subject to state nonattainment review (NHCAR Part Env-A 618), which requires the implementation of LAER, and the acquisition of offsets for its NO_X emissions.

LAER is defined as the most stringent emissions limitation which is contained in the implementation plan of any State for such a class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent. LAER will be implemented for the NO_X emissions from the Facility. The LAER analysis conducted for the Facility, and the LAER proposal for its NO_X emissions, is included in Section 5.

Sources subject to NH nonattainment review are required to obtain sufficient emission reductions from other sources so that the emissions from the source are less than the emission reductions. A new or modified source located in New Hampshire, outside of the 4-county ozone classified nonattainment region, must achieve an emissions offset ratio of at least 1.15 to 1. For a source located outside of the ozone classified or not classified nonattainment regions of the state, the offsets may be obtained from donor sources located anywhere within the northeast ozone transport region. Offsets obtained outside of New Hampshire are subject to the approval of the state or governing jurisdiction in which the offset donor source is located, as ensured by a federally enforceable permit, or other federally enforceable document. The emission reductions must be identified prior to issuance of the permit approval.

LBB will acquire sufficient emission reductions to offset the annual NO_X emissions from the Facility by a ratio of at least 1.15 to 1 prior to commencing operation, in accordance with the NHDES nonattainment review requirements. LBB will identify the source of the offsets prior to issuance of the temporary permit approval.

New sources subject to NH nonattainment review are also required to demonstrate that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location and construction by providing an analysis of alternative sites, sizes, production processes, and environmental control techniques.

LBB's business model is to develop biomass generating facilities at sites with existing infrastructure that meet specified criteria. LBB was made aware of the attributes associated with the Project Site that were found to be consistent with their business model. These attributes include:

- an existing boiler system which can be upgraded to function as efficient biomass fueled generating facilities and meet all applicable environmental requirements;

- proximity to fuel suppliers;
- accessibility to truck routes and/or rail lines for the delivery of fuel;
- proximity to transmission lines and an electrical interconnection;
- adequate water supply and delivery systems;
- adequate wastewater treatment infrastructure and treatment capacity; and
- a local workforce with the skills necessary to operate a generating facility

The former Pulp Mill site in Berlin uniquely satisfies all of LBB's criteria for a biomass generating facility. The former black liquor recovery boiler provides a unique opportunity to upgrade and convert existing equipment for renewable energy generation. The Site provides adequate acreage for the development of the Facility, as well as for other tenants, who could potentially provide synergistic services, bringing much needed jobs, taxes, and other revenues to the City of Berlin. The Site's history as a Pulp Mill and location within the North Country provide unique demonstrated access to a wood supply that is more than adequate to meet the Project's needs. There is a well trained local workforce within the City of Berlin that has direct experience with the Site and boiler operations. The former Pulp Mill site was the ideal site that met each of the criteria established by LBB for the siting of such a facility.

Alternate locations of site equipment, roadways, fuel piles, and conveying systems were considered during the Facility design process. As a result of the consideration of reasonable alternatives, the current Site Plan was determined to best facilitate efficient Facility operation, while minimizing impacts to natural resources and the surrounding community, and preserving adequate acreage for additional tenants at the site to potentially provide synergistic services to the Facility.

The selection of generation technology for the Facility was driven by the capabilities of the existing equipment on the Site, the large available supply of wood biomass fuel from regional sources, and the need for additional renewable energy sources in the state to meet its RPS goals.

LBB considered the benefits and impacts associated with the use of either a mechanical draft wet cooling tower or an air cooled condenser to meet the Project's cooling demand. The impacts considered for this analysis included water use, wastewater discharge, equipment footprint, impervious area, noise, emissions, and cost.

The use of a wet cooling tower will result in more efficient Facility operation, less fuel use, and fewer emissions for the same power output as an air-cooled facility. The use of the wet cooling tower, with a much smaller footprint, minimizes the overall Project footprint. There will also be lower noise levels associated with the use of wet cooling technology. As a result of this analysis, the use of a wet cooling tower was determined to be a preferred alternative for the Facility over an air-cooled condenser.

Several different control technologies were evaluated for use at the Facility. Section 5 of this application provides details of the emissions control technologies considered for the Facility for the determination of BACT and LAER.

This alternatives analysis demonstrates that the benefits of the Facility significantly outweigh the environmental and social costs imposed as a result of its location and construction.

4.1.3 Prevention of Significant Deterioration of Air Quality

As a new major stationary source located in an attainment area, the Facility will also be subject to the applicable PSD permit requirements. The NHDES has implemented the federal PSD Program permitting requirements (NHCAR Part Env-A 619) to determine if a new major stationary source will cause or contribute to significant deterioration of air quality in the state.

The PSD requirements include the completion of an air dispersion modeling analysis to demonstrate that the Project will not cause or contribute to an exceedance of the NAAQS, and that the maximum increases in ambient air concentrations of regulated air contaminants over the existing baseline do not exceed the allowable PSD increments. Section 7 details the air dispersion modeling analysis conducted for the Facility to demonstrate compliance with the PSD requirements.

The PSD program requires the implementation of BACT for each regulated NSR pollutant with potential emissions above the significance thresholds. Section 5 details the BACT analysis conducted for the Facility for each applicable pollutant.

The PSD program requires an analysis of ambient air quality in the area the source would affect for each pollutant with a potential to emit above the specified significance levels. According to the NHDES "Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire", July, 2006, background data for modeling compliance with AAQS are established by ambient air monitors located at various sites throughout the state. This guidance document directs sources to consult with NHDES on the most representative and appropriate background monitoring site to use for the modeling analysis. It also requires sources subject to the PSD requirements to consult with NHDES to determine the need for pre-construction ambient air monitoring.

The ambient air monitoring data from nearby monitors used to determine the background concentrations is representative of the area of the Facility. The maximum ambient air impacts from the Facility, as determined through air dispersion modeling, are below the Significant Monitoring Concentrations (SMC) established in the PSD rules. According to the PSD rules, the Administrator can exempt a source from pre-construction monitoring for a pollutant if the impact concentration for that pollutant is less than its respective SMC. Therefore, consistent with the PSD rules, a Preconstruction Monitoring Waiver is requested from NHDES for the Facility.

The PSD requirements also include additional impact analyses, including an analysis of the impairment to air quality, visibility, soils, and vegetation that would occur as a result of the source; impacts on general commercial, residential, industrial, and other growth associated with the source; and analysis of potential environmental justice issues. There are also additional impact analyses that are required due to the proximity of the Facility to a designated Class I area. Section 7 provides details on the additional impact analyses conducted for the Facility to address the additional PSD impact analysis requirements.

4.2 State Emissions Control Requirements

In addition to requiring that projects control emissions sufficiently to prevent exceedances of NAAQS, NHDES has established other regulations that impose specific emissions limitations or control requirements for certain pollutants from regulated sources. The following sections summarize the state emission control requirements applicable to the Facility, as well as how the Facility will comply with those requirements.

4.2.1 Ambient Air Quality Standards

NHCAR Chapter Env-A 300 establishes ambient air quality standards (AAQS) for various types of pollutants emitted in or transported into the State of New Hampshire. The standards are intended to be protective of the public health (primary standards) and the public welfare (secondary standards). The rule requires that the designated state AAQS be at least as stringent as the NAAQS, and that they not allow the significant deterioration of existing air quality in any portion of the state.

An air dispersion modeling analysis has been completed, which demonstrates that the emissions from the Facility will not cause or contribute to an exceedance of the state AAQS. Section 7 details the air dispersion modeling analysis completed for the Facility.

4.2.2 Standards for Certain New or Modified Facilities and Sources of HAPS

NHCAR Chapter Env-A 500 establishes state standards to regulate certain new or modified facilities in accordance with authority delegated by the EPA under §111(c) of the Clean Air Act, and certain sources of HAPS in accordance with authority delegated by the EPA under §112(c) of the Clean Air Act. It mandates compliance with the general provisions and the listed subparts of the NSPS and NESHAPS for the specified source categories.

The Facility will be subject to the applicable requirements of the NSPS, 40 CFR 60. As a major source of HAP emissions, the Facility will also be subject to the applicable MACT requirements of the NESHAPS established in 40 CFR 63. Section 4.3 details the NSPS and NESHAPS requirements applicable to the Facility, and the how LBB will comply with those requirements.

4.2.3 Testing and Monitoring Procedures

NHCAR Chapter Env-A 800 establishes minimum testing and monitoring procedures, calculation procedures, standards, and requirements in order to determine compliance with applicable state and federal statutes and rules. An initial compliance stack test will be conducted to demonstrate the Facility's compliance with its permitted emission limits. This testing will be conducted in strict accordance with the procedures of NHCAR Part Env-A 802, including submittal of a pre-test notice and a pre-test protocol at least 30 days prior to testing, conducting a pre-test meeting with NHDES staff at least 15 days prior to the test date, and submittal of a final test report documenting the results of the test no more than 60 days after completion of testing.

The Facility will have a certified continuous opacity monitoring system (COMS) and a continuous emissions monitoring system (CEMS) installed on the exhaust stack to meet the requirements of 40 CFR 60. The Facility COMS and CEMS will meet the minimum specifications of NHCAR Part Env-A 808.03. A CEM Monitoring Plan that meets the requirements of NHCAR Part Env-A 808.04 will be submitted to NHDES at least 90 days prior to installation of the monitoring systems. The performance specification testing required by NHCAR Part Env-A 808.05 will be conducted on the COMS and CEMS at the Facility within 180 days of initial system startup.

A quality assurance/quality control (QA/QC) plan that meets the requirements of NHCAR Part Env-A 808.06 will be prepared for the Facility COMS and CEMS. The Facility QA/QC plan will be reviewed and revised on an annual basis. The Facility COMS and CEMS will undergo quarterly auditing, in accordance with the specifications of NHCAR Parts Env-A 808.07 through 808.09. A written summary report of the results of all required audits will be submitted to NHDES within 30 calendar days following the end of each calendar quarter. LBB will also file quarterly emission reports with the NHDES within 30 days following the end of each calendar quarter, in accordance with NHCAR Parts Env-A 808.11 and 808.12.

4.2.4 Recordkeeping and Reporting Obligations

NHCAR Chapter Env-A 900 specifies the records that must be kept at sources that discharge air pollutants so that the emissions of those pollutants can be readily calculated or estimated and reported to the NHDES for the purposes of demonstrating compliance, compiling emission inventories, and developing air-related strategic plans. To comply with this Part, LBB will maintain records relating to energy production, material usage, equipment manufacturers' specifications, material safety data sheets, and fuel consumption. Records of fuel type and consumption will be maintained on a monthly basis. All records will be kept on file for a minimum of 5 years.

NHCAR Part Env-A 905 includes specific emission recording requirements for all sources with actual NO_X emissions greater than 10 tons per year, such as the Facility. To comply with this Part, LBB will maintain the required operational and fuel use records, including its operation schedule specifically during ozone season.

LBB will submit an annual emissions report to NHDES on or before April 15 of the year following the year covered by the report. The annual reports will include the actual emissions from the Facility, including the emissions of each regulated air toxic pollutant, as well as the annual Facility hours of operation and fuel usage, and any other information required to demonstrate compliance with the Facility's permit approvals.

In the event of a permit deviation, Facility personnel will investigate and take immediate corrective action to restore the affected device to within allowable permit levels. All information related to the permit deviation will be recorded, including the probable cause, duration, any corrective actions taken, and the amount of excess emissions which occurred as a result of the permit deviation. LBB will provide NHDES with the required notifications of permit deviations and submit semiannual reports that summarize all permit deviations reported during the previous reporting period.

4.2.5 Prevention, Abatement and Control of Open Source Air Pollution

NHCAR Part Env-A 1002 limits open air source pollution by regulating the direct emissions of particulate matter from mining, transportation, storage, use, and removal activities. It applies to activities that emit fugitive dust within the state, including commercial mining, construction, maintenance, demolition, bulk hauling, and storage activities. It requires that precautions be taken throughout the duration of such activities to prevent, abate, and control the emission of fugitive dust, including wetting, covering, shielding, or vacuuming. LBB will utilize such measures during the construction of the Facility, and for wood fuel transport and storage activities conducted during operation, to minimize the emissions of fugitive dust resulting from those activities.

4.2.6 Prevention, Abatement and Control of Stationary Source Air Pollution

NHCAR Part Env-A 1204 implements Reasonably Available Control Technology (RACT) requirements for certain VOC emitting sources in New Hampshire. The Facility does not have potential VOC emissions of 50 tons or more per year, and is therefore not subject to the NH VOC RACT regulations.

NHCAR Part Env-A 1211 implements the NO_X RACT requirements for sources in New Hampshire. According to NHCAR Part Env-A 1211.01(c), the NH NO_X RACT rule applies to electric steam utility boilers with a maximum heat input rate of 50 MMBtu or more. The Facility biomass boiler is subject to the NH NO_X RACT rule, and is required to meet the emission standards for electric utility boilers established in NHCAR Part Env-A 1211.04. The NO_X emission limits for electric utility boilers with a maximum heat input rate of 100 MMBtu or more, firing wood fuel, are 0.33 lb/MMBtu for boilers equipped with a traveling, shaker, or vibrating grate, and 0.25 lb/MMBtu for boilers equipped with a stationary grate, based on a 24-hour calendar day average.

The biomass boiler at the Facility will meet the applicable NH NO_X RACT emission standard. Compliance with the NO_X RACT emission standard will be demonstrated through the use of a certified CEMS. LBB will meet the applicable recordkeeping and reporting requirements of NHCAR Chapter Env-A 900 to satisfy the NO_X RACT rule.

NHCAR Part Env-A 1211.11 establishes emission standards and control options for emergency generators and engines. It applies to emergency engines located at a source with potential NO_X emissions greater than 50 tons per year, unless their operation is limited to less than 500 during any consecutive 12-month period, and the potential NO_X emissions from the engines are limited to less than 25 tons for any consecutive 12-month period. The emergency fire pump at the Facility will be limited to 500 hours of operation during any consecutive 12-month period, and will have permitted potential NO_X emissions less than 25 tons per consecutive 12-month period. Therefore the fire pump is exempt from the provisions of NHCAR Part Env-A 1211.11.

4.2.7 Regulated Toxic Air Pollutants

NHCAR Chapter Env-A 1400 establishes rules to prevent, control, abate and limit the emissions of toxic air pollutants into the ambient air to promote public health. One of the source categories which is exempt from the requirements of the rule is the combustion of untreated wood. Therefore, the emissions from the biomass boiler are not subject to the state regulated toxic air pollutants rule requirements. Both the emergency generator and the fire pump will utilize virgin distillate fuel oil and are similarly exempt from the NH air toxics regulation.

There will be emissions of NH_3 from the SCR emissions control system. Additionally, the use of certain water treatment chemicals in the cooling tower will result in emissions of sodium bisulfite and sodium hydroxide (contained in the cooling tower drift) above the de-minimis emission rate levels specified in Env-A 1400. The air dispersion modeling analysis conducted for the Facility demonstrates that the maximum predicted ambient air impacts for NH_3, sodium bisulfite, and sodium hydroxide, at or beyond the property line, are less than the respective 24-hour and annual ambient air limits (AALs) established in Table 1450-1 of NHCAR Chapter Env-A 1400. The Facility will therefore comply with the NH Regulated Air Toxics rule.

4.2.8 Fuel Specifications

NHCAR Chapter Env-A 1600 establishes limits on the content of fuels used in combustion processes to limit the emissions of pollutants into the ambient air. It contains content limitations for specified liquid, gaseous, and solid fuels. However, wood fuel is not listed as a solid fuel subject to this Chapter; therefore the Facility is not subject to its solid fuel requirements and limitations.

The Facility will utilize ULSD for the boiler startup burners and the diesel fire pump. NHCAR Part 1604.01 limits the sulfur content of No.2 distillate oil to 0.40 percent sulfur by weight. The Facility will utilize ULSD with a sulfur content of 0.0015 percent by weight, and will therefore comply with the state fuel oil sulfur content standard.

4.2.9 Fuel Burning Devices

NHCAR Chapter Env-A 2000 establishes emission standards for particulate matter and visible emissions from stationary fuel burning devices. For stationary fuel burning devices installed after May 13, 1970, the owner or operator may not cause or allow average opacity in excess of 20% for any continuous 6-minute period. For steam generating units subject to NSPS, during periods of startup, shutdown, and malfunction, average opacity is allowed in excess of 20% for one period of 6 continuous minutes in any 60-minute period. For stationary fuel burning devices installed after January 1, 1985, with a maximum gross heat input rate equal to or greater than 250 MMBtu/hr, the maximum allowable particulate matter emission rate is 0.10 lb/MMBtu.

A certified COMS will be installed on the boiler exhaust stack to monitor and record continuous compliance with the state opacity limits for fuel burning devices. The maximum PM emission rate from the biomass boiler of 0.010 lb/MMBtu is an order of magniture lower than the state particulate matter emission standard. A stack test will be conducted to demonstrate compliance with the state particulate matter standard, in accordance with the requirements specified in Env-A 802.02.

As the diesel fire pump has a maximum heat input rating less than 100 MMBtu/hr, and will be installed after January 1, 1985, it will be subject to a particulate matter emission limit of 0.30 lb/MMBtu. The unit will be certified by its manufacturer to meet this emission standard.

4.2.10 NO_X Budget Trading Program

NHCAR Chapter Env-A 3200 implements the NO_X Budget Program, which requires reductions in ozone season NO_X emissions from budget sources to achieve the NAAQS for ozone. A NO_X budget source is defined as a fossil fuel fired boiler or heat exchanger with a maximum rated heat input capacity of 250 MMBtu/hr or more, and all electric generating devices with a rated output of 15 MW or more. An electric generating device is defined in the regulation as any fossil-fuel fired combustion device of 15 MW capacity or greater which provides electricity for sale or use.

The biomass boiler at the Facility will utilize wood fuel, not a fossil fuel, for the generation of electricity. The boiler is therefore not a NO_X budget source, and the Facility is not subject to the requirements of the NO_X Budget Program.

4.2.11 NO_X Emissions Reduction Fund for NO_X Emitting Generation Sources

NHCAR Chapter Env-A 3700 requires NO_X emitting generation sources to report power generation and NO_X emissions information, and to either acquire emissions reduction credit mechanisms, or to make direct payment of fees to the NO_X emissions reduction fund. NO_X emitting generation sources are defined as any internal combustion engine or combustion turbine which generates electricity for use or sale, except for sources which meet the definition of a NO_X budget source.

The biomass boiler at the Facility does not meet the definition of a NO_X emitting generation source, as it is not an internal combustion engine nor a combustion turbine. The Facility is therefore not subject to the requirements of NHCAR Chapter Env-A 3700.

4.2.12 Carbon Dioxide (CO_2) Budget Trading Program

NHCAR Chapter Env-A 4600 establishes the NH State CO_2 Budget Trading Program, which is designed to stabilize, and then reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in the state, in an economically efficient manner. This program applies to any unit that, at any time on or after January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe. A unit is defined as a fossil-fuel fired stationary boiler, combustion turbine, or combined cycle system. A source that includes one or more of such units is a CO_2 budget source.

The biomass boiler at the Facility will utilize wood fuel, not a fossil fuel, for the generation of electricity. As the Facility will utilize ULSD fuel only for startup, the boiler is not a CO_2 budget source, and the Facility is not subject to the requirements of the CO_2 Budget Trading Program.

4.3 Federal Emissions Control Requirements

4.3.1 New Source Performance Standards

4.3.1.1 Biomass Boiler

40 CFR 60, Subpart Db, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" (Subpart Db), applies to steam generating units that are capable of combusting more than 100 MMBtu/hr heat input of fuel, and for which construction, modification, or reconstruction is commenced after June 19, 1984. The biomass boiler at the Facility is subject to the requirements of Subpart Db NSPS.

The PM emissions from an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 must not exceed 0.10 lb/MMBtu heat input. The emissions must not exhibit greater than 20 percent opacity for a 6-minute average, except for one 6-minute period per hour of no more than 27 percent opacity. There are no SO_2 or NO_X emission limits established for wood-fired boilers in Subpart Db.

The oil-fired start up burners will take a federally enforceable limit to operate with less than a 10% annual capacity factor and will combust ULSD. Therefore, operation of the oil burners is not subject to the requirements of Subpart Db.

The Facility will demonstrate compliance with each applicable Subpart Db emission limit. An initial performance test will be conducted to demonstrate compliance with the PM emission limit. Subsequent PM performance tests will be conducted on an annual basis. A certified COMS will be installed on the boiler exhaust stack to continuously monitor and record compliance with the Subpart Db opacity standard. All monitoring systems will meet the design specifications and will undergo the certification and auditing procedures established in Subpart Db.

Written notification of the date construction of the boiler commenced will be postmarked within 30 days after that date. A notification of the actual date of initial startup will be postmarked within 15 days after that date. A notification of any physical or operational change which may increase the emission rate of any air pollutant for which a standard applies will be postmarked within 60 days or as soon as practicable before the change is commenced. A notification of the date upon which demonstration of the COMS/CEMS performance commences will be postmarked not less than 30 days prior to that date.

Records will be maintained at the Facility of all information needed to demonstrate compliance with Subpart Db, including performance tests, monitoring data, and calculations. The results of all performance tests and COMs/CEMS performance audits conducted at the Facility, and all recorded emissions data, including emissions exceedances, will be submitted to the Administrator semiannually for each six month period. All of the semiannual reports will be postmarked by the 30th day following the end of each six-month period.

4.3.1.2 Emergency Fire Pump

Stationary compression-ignition (CI) internal combustion engines (ICE), including fire pump engines certified by the National Fire Protection Association (NFPA), that are manufactured after July 1, 2006, and commence construction after July 11, 2005 must meet the requirements of 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." Fire pump engines must comply with the emission standards listed in Table 4 of the NSPS.

The diesel fuel fired by emergency fire pump engine must meet the requirements of 40 CFR 80.510(a), which limits the sulfur content to 500 ppm or less. Beginning October 1, 2010, the fuel requirements of 40 CFR 80.510(b) must be met, which limits fuel sulfur content to 15 ppm or less.

The diesel fire pump will be certified to meet the applicable emission standards set forth in Table 4 of the regulation. The emergency fire pump will be installed, configured and operated according to the manufacturer's specifications. The emergency fire pump will be equipped with a non-resettable hour meter. Maintenance checks and readiness testing will be limited to 100 hours per year and annual operations will be limited to 500 hours. The ULSD fuel fired by the emergency diesel fire pump will meet the NSPS fuel sulfur content limit.

Records will be kept of the operation of the emergency diesel fire pump, and of all non-emergency service that are recorded by the non-resettable hour meters. An initial notification of construction or operation is not required, nor will there be any additional record keeping or reporting required to comply with the NSPS beyond that summarized above.

4.3.2 National Emissions Standards for Hazardous Air Pollutants

The EPA has also established NESHAPS (40 CFR 63) which require MACT for regulated emissions sources. These regulations apply to major HAP sources, or facilities with potential emissions greater than 25 tons per year of all listed HAPs or 10 tons per year of any individual listed HAP. The Facility will be a major source of HAP emissions and be subject to the General Provisions of 40 CFR 63 (Subpart A).

4.3.2.1 Biomass Boiler

40 CFR 63, Subpart DDDDD established national emission standards and operating limits for HAP emissions from institutional, commercial, and institutional boilers, process heaters, and electric steam utility generating boilers not fired by fossil fuels. Subpart DDDDD was vacated on June 8, 2007 for further documentation. Therefore, as a major source of HAP emissions,

a case-by-case MACT determination is required for the Facility sources not subject to a 40 CFR 63 MACT standard, in accordance with 40 CFR 63, Subpart B. Section 6 details the case-by-case MACT determination conducted for the biomass boiler.

A notification of intention to construct a new affected source will be submitted in writing to the Administrator for the Facility. A notification of the actual date of startup of the Facility will be postmarked within 15 days after that date.

The Facility will be operated and maintained at all times in a manner consistent with safety and air pollution control practices for minimizing emissions. A written startup, shutdown, and malfunction plan will be developed for the Facility equipment, with procedures for operating and maintaining the equipment during such periods, and a program for corrective action during periods of equipment malfunction. Records will be kept at the Facility of all startup, shutdown, and malfunction periods, including all corrective actions taken, and compliance with the Facility plan for such periods.

A performance test will be conducted at representative operating conditions within 180 days of startup, to demonstrate compliance with the approved MACT emission standards. A notification of the performance test and a site-specific test plan will be submitted to the Administrator at least 60 days prior to the initial performance test. The results of the performance test will be submitted to the Administrator within 60 days following the completion of the testing.

Records will be kept at the Facility on the occurrence and duration of all startups, shutdowns, and equipment malfunctions, as well as on all required maintenance performed on all air pollution control and monitoring equipment. Records will also be kept of all performance tests and notifications. The Facility will submit semiannual reports of excess emissions to the Administrator.

4.3.2.2 Emergency Diesel Fire Pump

40 CFR 63, Subpart ZZZZ, establishes national emission and operating limitations for HAP emissions from stationary reciprocating internal combustion engines (RICE) located at major sources of HAP emissions. It also establishes requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

In accordance with 40 CFR 63.6590(b)(1)(i), a new stationary emergency RICE with a site rating greater than 500 brake Hp does not have to meet the requirements of Subpart ZZZZ or the requirements of Subpart A, except for the initial notification requirements.

5.0 BACT/LAER ANALYSIS

The PSD program requires the implementation of BACT for each regulated NSR pollutant with potential emissions above its respective significance threshold. For the Facility, these pollutants are NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4. BACT is defined in the PSD rules as an emissions limitation based on the maximum degree of reduction for each pollutant, as determined on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such a source through the application of production processes or available methods, systems, or techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such a pollutant.

The determination of BACT is made through a "top-down" analysis of potentially viable control technologies starting with the approach that provides the greatest level of emission control. Technologies that result in higher emissions can only be considered if the more efficient control technology evaluated is determined to be either technically or economically infeasible. Applicants are required to consider all control measures that are potentially applicable and have been demonstrated in practice, including consideration of potential technology transfer from similar types of emissions sources. This requirement will assure that the emissions from the Facility are controlled to the greatest degree possible for a facility of this type.

The following steps are followed in this BACT top-down analysis:

Step 1 - Identify All Control Technologies

Step 2 - Eliminate Technologically Infeasible Options

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Step 4 - Cost Effectiveness Analysis

Step 5 - Select BACT

Control options are first evaluated for their technical feasibility. Options found to be technically feasible are ranked by control efficiency. In the event the most stringent level of control is ruled out due to cost, energy consumption, or environmental impacts, the next most stringent level of control is analyzed until BACT is determined. An analysis of other control technologies is not necessary if the technology proposed is the highest level of control found technically feasible.

As a major source of NO_X emissions located in the northeast ozone transport region, the Facility is also required to implement LAER for its NO_X emissions. LAER is defined as the most stringent emission limitation contained in any State Implementation Plan (SIP) for a source category, or the most stringent emissions limitation which is achieved in practice for a source category. LAER may be achieved by a combination of a change in the raw material processes, a process modification, and/or add-on emission controls.

To complete the BACT/LAER analysis for the Facility, control technologies demonstrated in practice for similar sources, and corresponding emission limits established by various state agencies and the EPA were reviewed. BACT/LAER determinations listed in the USEPA RACT/BACT/LAER Clearinghouse (RBLC), the South Coast Air Quality Management District BACT determinations, the California Air Resources Board's BACT Clearinghouse Database, and any available recently issued air permits were also reviewed. The review was limited to wood-fired boilers permitted since 2000. The information gathered from these sources was used in determining the proposed BACT/LAER emission levels. This control technology analysis demonstrates that the proposed biomass boiler emissions are consistent with recent BACT/LAER determinations for similar sources.

The following sections provide a discussion of the emission control techniques that were considered to control the emissions from the Facility and the selected BACT/LAER proposal for each pollutant.

5.1 Biomass Boiler

5.1.1 Nitrogen Oxides

NO_X emissions from boilers result from fuel-bound nitrogen and thermal NO_X formation in the combustion zone. Thermal NO_X is the predominate source of NO_X emissions for a boiler due to the high combustion temperatures. NO_X emissions from boilers are controlled though fuel optimization and combustion controls to minimize NO_X formation, and add-on air pollution control systems to reduce NO_X emissions.

5.1.1.1 Control Technologies

5.1.1.1.1 Selective Catalytic Reduction (SCR)

SCR using ammonia as a reagent represents the state-of-the-art and the most stringent level of control available for back-end NO_X removal for biomass-fired boilers. The technology uses ammonia (NH_3) to reduce NO_X to N_2 and H_2O in the presence of a catalyst. The general chemical reactions are:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$; and

$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$.

Ammonia is injected into the SCR in excess of stoichiometric amounts to achieve maximum conversion of NO_X. Although this reduces NO_X emissions substantially, some of the ammonia does not react, passes through the SCR reactor, and is exhausted to the atmosphere. This is called "ammonia slip." The determination of the level for NH_3 "slip" is linked to the achievable NO_X level, in that achieving the lowest possible NO_X level will result in greater potential for NH_3 slip. Therefore, this LAER analysis considers the NO_X/NH_3 on a combined basis.

Several different types of catalysts can be used to accommodate various available flue gas temperatures. Base metal catalysts (typically containing vanadium and/or titanium oxides) have been commonly used in recent biomass boiler projects. Base metal catalysts are useful between 450°F and 800°F. Historically, SCR has been used successfully to achieve high levels of NO_X control (85 to 90%) where the catalyst can be placed in the ideal temperature zone of the combustion process. For natural gas and oil-fired combustion boilers, where PM emissions are relatively low, the catalyst is usually placed in the boiler exhaust prior to the economizer where temperatures allow for peak removal efficiency by the catalyst (Generally referred to as a 'hot-side' installation). However, in the case of biomass boilers, the high particulate matter loading from the combustion zone and boiler will cause the SCR catalyst bed to quickly plug. For applications with high PM loadings, such as coal and wood-fired boilers, one alternative is to locate the catalyst after the PM control device or "clean side" as it commonly referred to. Therefore, in order to achieve maximum NO_X control by 'hot side' SCR systems, the exhaust gas must then be re-heated to achieve the necessary higher temperatures (650°F to 800°F) prior to entering the SCR catalyst bed. The energy and equipment required to raise the exhaust gas temperature to the ideal range is extensive and very costly.

An alternative to this is the use of the same 'hot-side' SCR system; however, installing it in a location after the PM control device where the exhaust temperatures are at the lower end of the catalyst performance range (450°F to 600°F). This is commonly referred to as a 'cold-side' installation. Even at such a location, with proper gas and ammonia distribution across the catalyst bed, the SCR is able to achieve up to 70% NO_X removal. In a review of recent LAER determinations available from regulatory agencies or published in the BACT/LAER Clearinghouse database, the use of CSCR with a wood-fired boiler has been demonstrated to reduce NO_X to an emission rate of 0.065 lb/MMBtu.

5.1.1.1.2 Selective Non-Catalytic Reduction (SNCR)

Selective Non Catalytic Reduction (SNCR) is NO_X emissions control technology using the injection of a reagent NH_3 or Urea which in turn react with oxides of nitrogen to reduce those compounds to N_2 and water. This reaction takes place without the use of a catalyst but must take place in a narrow high temperature 'window' to be effective. The technique requires thorough mixing of the reagent into the furnace chamber with at least 0.5 seconds of residence time at a temperature above 1600ºF and below 2100ºF. Moderate NO_X reductions in the order of 40% to 60% are achievable in practice under ideal process and operating conditions.

5.1.1.1.3 Combustion Controls

Use of combustion controls to reduce NO_X is an available technology; however, there are limitations to its use on a biomass boiler. As mentioned above, the formation of NO_X from the combustion of wood is a result of two mechanisms; oxidation of nitrogen bound in the wood (fuel-bound NO_x) and the high temperature formation of NO_X from the nitrogen component of the required combustion air (thermal NO_X). Combustion controls for reduction consists primarily of staged combustion and control of the peak flame temperature by either use flue gas recirculation or controlled flame geometry. For solid-fuel fired combustion units, combustion controls have resulted in overall NO_X reductions in the range of 15% to 40%.

5.1.1.2 Prior BACT/LAER Determinations & Permit Limits

The lowest permitted NO_X emission rate for a wood fired boiler identified is 0.060 lb/MMBtu for the Russell Biomass project in Massachusetts, which was permitted in 2008, but not yet constructed. The Concord Steam project in New Hampshire was permitted at 0.065 lb/MMBtu in 2009, as was the Schiller Station project in 2004. All of these facilities proposed SCR as the BACT/LAER determination.

5.1.1.3 BACT/LAER Determination

The use of fuel optimization, good combustion practices, and CSCR will result in a NO_X emission rate from the biomass boiler no greater than 0.060 lb/MMBtu of heat input based on a 30-day rolling average during normal operation. This emission rate is consistent with lowest permit limit for any similar recently permitted facility and is therefore the BACT/LAER determination for the Facility.

5.1.2 Carbon Monoxide

Carbon monoxide (CO) formation in boilers results from incomplete combustion of the fuel. There are many factors that can impact CO formation in boilers, including the boiler design, the fuel quality and moisture content, the air to fuel mix and distribution, and the combustion temperature and residence time. CO emissions from boilers are reduced with increased excess air, higher combustion temperatures, and longer residence times. However, these measures can result in an increase in NO_X emissions, so good combustion practices must be utilized to balance the emissions of NO_X and CO from a boiler.

5.1.2.1 Control Technologies

5.1.2.1.1 Oxidation Catalyst

Oxidation catalysts can reduce CO emissions by promoting the oxidation of CO to CO_2 and water as the emission stream passes through the catalyst bed. The oxidation process takes places spontaneously, without the requirement for introducing reactants. Oxidation catalysts typically operate within a temperature range from 700 to 1,100°F and are commonly installed on natural gas fired combustion turbines, with exhaust gases that are much cleaner than from wood fired boilers. Wood fired boilers operate at higher temperatures and their exhaust gases contain more particulates than gas fired sources which can contaminate and eventually plug the catalyst bed, requiring significant costs to maintain the catalyst to its design control efficiency.

5.1.2.1.2 Combustion Controls

The use of combustion controls to reduce the formation of CO is an effective control technology for solid fuel fired combustion processes. Combustion controls include BFB combustion technology, the use of FGR, excess air and fuel/air mixing to reduce products of incomplete reduction (CO and VOC) while not creating excessive thermal NO_X.

5.1.2.2 Prior BACT Determinations & Permit Limits

The lowest permitted CO emission rate for a wood fired boiler identified is 0.075 lb/MMBtu for the Russell Biomass project in Massachusetts, which was permitted in 2008 with oxidation catalyst. The Schiller Station project in New Hampshire was permitted at 0.100 lb/MMBtu in 2004 using a Fluidized Bed Combustor without an oxidation catalyst.

5.1.2.3 BACT Determination

The use of BFB combustion technology in the boiler design, good combustion practices, and fuel optimization will result in a CO emission rate from the biomass boiler no greater than 0.075 lb/MMBtu of heat input on a 24-hour daily block average when operating at 70% load or greater. This emission rate is consistent with permit limits for similar facilities recently permitted, and is therefore the BACT determination for the Facility.

5.1.3 Sulfur Dioxide/Sulfuric Acid Mist

Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions from boilers result from oxidation of the sulfur in the fuel. The primary means for controlling SO_2 and H_2SO_4 emissions from wood-fired boilers is to limit the sulfur content of the fuel. There are also add-on control systems in use for wood-fired boilers, including spray dryer adsorbers, lime or dry sodium bicarbonate injection, or wet scrubber systems.

5.1.3.1 Control Technologies

5.1.3.1.1 Spray Dryer/Adsorbers

The use of spray dryers or adsorbers to control SO_2 is an effective control technology. The technology involves the use of a vessel into which a slurry of a reagent such as sodium hydroxide, is sprayed into the hot gas flue stream. The intimate contact of the reagent with the SO_2 present in the flue gas (combined with proper humidity & retention time), results in the formation of sodium salts which can then be removed in the downstream particulate removal device. Spray Dryer/Adsorbers are generally used where the SO_2 content of the flue gas is significant and thus warrants high SO_2 removal efficiencies. Generally, biomass energy facilities operate with fuels of very low sulfur content not warranting high SO_2 removal efficiencies.

5.1.3.1.2 Dry Sorbent Inject

Dry sorbent injection involves the addition of a dry reagent such as limestone or sodium bicarbonate into the hot combustion zone to reduce the oxidation of fuel-bound sulfur to SO_2. Under proper high temperature conditions, mixing, and retention time, the sulfur converts directly to sodium salts in the combustion zone and then removed as a particulate downstream in the particulate removal device. Clean wood biomass fuel such as that proposed for use by the Facility typically has a very low sulfur content that does not require the use of dry sorbent injection. However, data available from the Project's BFB technology provider indicates a wide degree of variability in SO_2 emissions from various wood boilers around the country. To assure that the Facility's SO_2 emissions can be maintained within the proposed BACT emission limit, a dry sorbent injection system will be installed.

5.1.3.1.3 Wet Scrubbers

Wet scrubbers generally utilize either cross-flow or counter flow vessels with packed beds and re-circulating scrubbing liquid streams. The water streams contain a reagent such as sodium hydroxide to react under saturated conditions with the SO_2 entering the scrubber. SO_2 is highly soluble in water and wet scrubbers can therefore, be very effective in controlling SO_2 emissions. However, several issues have precluded its use in biomass fired plants. The resulting saturated flue gas results in a highly visible, dense plume during most of the year. In colder climates, this saturated plume may cause icing or fogging of local roadways and vistas. If the flue gas requires further particulate matter control downstream of the wet scrubber, the gas must be re-heated to raise the temperature above the dew point to prevent condensation in the downstream equipment.

5.1.3.1.4 Fuel Sulfur Content Control

Emissions of SO_2 are a direct result of fuel sulfur content. Relative to other solid fuels, wood biomass has very low levels of sulfur which generally precludes the need for further SO_2 reduction. In recent stack testing of operating biomass units in the northeast, SO_2 levels have been demonstrated to be a fraction of the US EPA AP-42 emission factor used in the original permitting process for most biomass units.

5.1.3.2 Prior BACT Determinations & Permit Limits

The lowest permitted SO_2 emission rate identified for a wood fired boiler located in the northeast United States is the Schiller Station project in New Hampshire, which was permitted at 0.020 lb/MMBtu in 2004 using lime injection. The Russell Biomass project in Massachusetts was permitted in 2008 with an SO_2 emission rate of 0.025 lb/MMBtu using clean fuels and no add-on controls. The lowest permitted SO_2 emission rate for a similar size BFB boiler in the United States is 0.014 lbs/MMBtu for the Yellow Pine Energy Company in Georgia, based on the use of a dry scrubber system.

The lowest permitted H_2SO_4 emission rate for a wood fired boiler identified is the Stevenson Mill project in Alabama, which was permitted at 0.022 lb/MMBtu in 2006 using clean fuels and no add-on controls.

5.1.3.3 BACT Determination

The Facility will utilize wood fuel which has an inherently low sulfur content. A dry sorbent injection system will also be installed to address any potential variability in the wood fuel sulfur content and assure that SO_2 emissions are no greater than 0.012 pounds per million Btu of heat input during normal operation. Based on experience with other generating facilities using an SCR system, no more than 10% of the SO_2 generated in the boiler is expected to be further oxidized to SO_3 and combine with water vapor in the flue gas to form H_2SO_4. The resulting H_2SO_4 emission rate is expected to be less than 0.002 lb/MMBtu. These emission rates are consistent with permit limits for similar facilities recently permitted, and are therefore the BACT determinations for the Facility.

5.1.4 Particulate Matter

Particulate matter (PM) from fuel combustion is primarily the result of non-combustible constituents (ash) in the fuel. In less efficient combustion systems, particulate may also be comprised of soot resulting from unburned hydrocarbons. In combustion systems that utilize CSCR controls, a small fraction of the particulate emissions is ammonium bisulfate compounds formed when the ammonia reagent reacts with sulfur trioxide.

5.1.4.1 Control Technologies

5.1.4.1.1 Mechanical Collectors (Multiclones or Centrifugal Separators)

The use of mechanical collectors such as multiclones or centrifugal separators, has primarily been limited to initial control of large particulate matter and burning embers from wood-fired boilers. Several installations have used these separators to prevent fires in the downstream fabric filters were applicable. Multiclones and centrifugal separators are not generally used as the primary control device for particulate matter based on their inherent low level of removal.

5.1.4.1.2 Electrostatic Precipitators

ESP are used on numerous solid fuel and wood-fired boilers in the US. ESP have been designed for very high levels of particulate removal, similar to a fabric filter, without the likelihood of fires caused by carry-over of burning embers. PM Removal efficiencies achieved by ESP approach or equal that of fabric filters when properly designed.

5.1.4.1.3 Fabric Filters

Fabric filters (or otherwise referred to as baghouses) utilize a filter media for capture of particulate from combustion processes and process sources. Like ESPs, fabric filters can provide in excess of 99% particualte removal efficiency and are particularly well suited for boilers using dry sorbent injection. Although some concerns have been raised regarding baghouse fires on boilers employing older combustion technologies such as stokers, the BFB technology that will be employed by the Facility eliminates such concerns due to the high fuel conversion efficiency in the boiler.

5.1.4.2 Prior BACT Determinations & Permit Limits

The lowest permitted PM emission rate for a wood fired boiler identified is 0.01 lb/MMBtu for the revised PSNH-Schiller Station permit issued in 2006 using a baghouse to control PM emissions. The Yellow Pine energy Company in Georgia was issued a permit for a wood fired BFB boiler in 2009 with a PM limit of 0.01 lb/MMBtu also employing a baghouse for PM control. Several other wood fired boiler projects have been recently permitted with PM emission rates ranging from 0.012 to 0.020 lb/MMBtu.

5.1.4.3 BACT Determination

The Facility will use fuel optimization, combined with state-of-the-art combustion technology and operating controls, as well as a fabric filter baghouse to provide the most stringent degree of particulate emissions control available for a wood-fired boiler. These measures will result in a filterable $PM/PM_{10}/PM_{2.5}$ emission rate no greater than 0.010 lb/MMBtu of heat input during normal operation. This emission rate is consistent with the most stringent permit limits for similar facilities recently permitted, and is therefore the BACT determination for the Facility.

5.2 Cooling Tower

The source of emissions from a cooling tower is the solids component in the droplets of recirculated water that are carried out of the tower by the cooling fans. This is known as cooling tower 'drift'. The cooling tower proposed for the Facility will utilize a state-of-the-art drift eliminator that limits drift to 0.005% of the recirculating liquid rate. According to the RBLC, this level of control is consistent with other cooling towers recently permitted at similar projects, and is therefore considered the BACT determination for the Facility.

5.3 Emergency Fire Pump Engine

The driver engine for the emergency diesel fire pump will be fueled with ULSD and be certified to meet the applicable EPA Tier 3 emission standards as set forth in 40 CFR 89. Compliance with the EPA Tier 3 emission standards, the use of ULSD fuel, in combination with a limit of 500 hours per year of total operating time for each engine is considered BACT for these sources, consistent with the determinations from other similar, recently permitted projects.

6.0 CASE-BY-CASE MACT DETERMINATION

The NESHAP for electric utility boilers firing solid fuels (40 CFR 63, Subpart DDDDD) was vacated and remanded for further documentation in 2007. As the Facility will be a major source of HAP emissions, a case-by-case MACT determination is required for the biomass boiler to satisfy the requirements of Section 112(g) of the Clean Air Act and 40 CFR 63.40-44 (Subpart B). If EPA promulgates a revised final rule that establishes emission limits that are applicable to the biomass boiler that are more stringent than the Facility MACT determination, the Facility will be required to comply with those emission limits as expeditiously as possible, and within eight years from their promulgation.

40 CFR 63, Subpart B defines the MACT emission limitation for a new source as the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed source. A similar source is defined as a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology.

A case-by-case MACT analysis relies on available information regarding previous MACT determinations, permitted emission limits, and control technologies utilized for similar sources. The RBLC and available permits were reviewed during the completion of the MACT analysis for the Facility. The following sections detail the case-by-case MACT determination for each of the pollutants previously regulated by the vacated Boiler MACT standard.

6.1 Particulate Matter (PM)

6.1.1 Determination of MACT Floor for PM

A review of recent permit approvals and installations for similar wood-fired projects yielded limited results for previous MACT determinations. However, the most recent BACT/LAER determinations for PM are also considered. The most recent applicable determinations for PM emission rates for similar projects are as follows:

Schiller Station (NH)= 0.01 lb/MMBtu

Yellow Pine Energy Company (GA) = 0.01 lb/MMBtu

Russell Biomass (MA) = 0.012 lb/MMBtu

South Point Biomass (OH) = 0.012 lb/MMBtu

Based on additional information from the RBLC, the range of determinations for PM over the previous five-year period was 0.15 to 0.02 lb/MMBtu. Therefore, the EPA's originally promulgated MACT Standard for PM (0.026 lb/MMBtu) for a new, solid fuel-fired boiler of this size is considered to be appropriate as the MACT floor.

The Berlin Biomass Project is proposing a PM limit of 0.010 lb/MMBtu as BACT and therefore, is more stringent than the MACT floor determined on a case-by-case basis.

6.1.2 Proposed PM Emission Limit

PM Emissions Limit	Control Technology Description	Monitoring Parameters
0.010 lb/MMBtu	Combustion Controls inherent to Bubbling Fluidized Bed boilers; fabric filter (baghouse) add-on control.	Continuous Opacity Monitoring Systems (COMS) and Combustion Parameters

6.2 Hydrogen Chloride (HCl)

6.2.1 Determination of MACT Floor for HCl

As with PM, a review of recent permit approvals and installations for similar wood-fired projects yielded limited results for previous MACT determinations for HCl. However, the most recent BACT/LAER determinations for HCl emission rates for similar projects are as follows:

Schiller Station (NH)= 0.02 lb/MMBtu

Russell Biomass (MA) = 0.02 lb/MMBtu

South Point Biomass (OH) = 0.0172 lb/MMBtu

Based on additional information from the RBLC, the range of determinations for HCl over the previous five-year period was 0.0172 to 0.026 lb/MMBtu. Therefore, the EPA's originally promulgated MACT Standard for HCl (0.02 lb/MMBtu) for a new solid fuel-fired boiler of this size seems to be appropriate as the MACT floor.

The Berlin Biomass Project is proposing an HCl limit of 0.000834 lb/MMBtu and therefore, is more stringent than the MACT floor determined on a case-by-case basis. The emissions limit is based on stack test data provided by the NHDES as well as recently issued permit determinations for similar facilities.

6.2.2 MACT HCl Emission Limit Recommendations

HCl Emissions Limit	Control Technology Description	Monitoring Parameters
0.000834 lb/MMBtu	Fuel Analysis or Stack Test	Fuel Quality

6.3 Mercury

6.3.1 Determination of MACT Floor for Mercury

A review of recent permit approvals and installations for similar wood-fired projects yielded limited results for previous MACT determinations for Mercury (Hg). However, the most recent BACT/LAER determinations for Hg emission rates for similar projects are as follows:

Schiller Station = 0.000003 lb/MMBtu

Russell Biomass = 0.0000012 lb/MMBtu

South Point Biomass (OH) = 0.000009 lb/MMBtu

MACT for a new source is defined as the emissions limitation achieved in practice by the best controlled similar source (emphasis added). The Russell Biomass project has not yet started construction and therefore has not demonstrated in practice that their proposed emissions limitation can be achieved. Based on additional information from the RBLC, the range of determinations for Hg over the previous five-year period was 0.000009 to 0.000003 lb/MMBtu. Therefore, the EPA's originally promulgated MACT Standard for Hg (0.000003 lb/MMBtu) for a new solid fuel-fired boiler of this size seems to be appropriate as the MACT floor.

The Berlin Biomass Project is proposing an Hg limit of 0.000003 lb/MMBtu and therefore, is as stringent as the MACT floor determined on a case-by-case basis.

6.3.2 MACT Hg Emission Limit Recommendations

Mercury Emissions Limit	Control Technology Description	Monitoring Parameters
0.000003 lb/MMBtu	Fuel Analysis or Stack Test	Fuel Quality

6.4 Organic HAPS (Carbon Monoxide as surrogate)

6.4.1 Determination of MACT Floor for Organic HAPs

A review of recent permit approvals and installations for similar wood-fired projects yielded limited results for previous MACT determinations for Organic HAPS using Carbon Monoxide (CO) as the surrogate. However, the most recent BACT/LAER determinations for CO emission rates for similar projects are as follows:

Schiller Station = 400 ppm @ 7% O_2

Russell Biomass = 0.075 lb/MMBtu (equivalent to 95 ppm @ 3 % O_2)

South Point Biomass (OH) = 0.10 lb/MMBtu (equivalent to 130 ppm @ 3% O_2)

Based on additional information from the RBLC, the range of determinations for Hg over the previous five-year period was 0.78 to 0.1 lb/MMBtu (130 ppm to 1000 ppm). Therefore, the EPA's originally promulgated MACT Standard for CO (400 ppm @ 3% O_2) for a new solid fuel-fired boiler of this size seems to be appropriate as the MACT floor.

The Berlin Biomass Project is a CO limit of 0.075 lb/MMBtu (95 ppm @ 3% O_2) as BACT and therefore, is more stringent than the MACT floor determined on a case-by-case basis.

6.4.2 MACT Organic HAPS (CO) Emission Limit Recommendations

Organic HAPS (CO) Emissions Limit	Control Technology Description	Monitoring Parameters
0.075 lb/MMBtu	Combustion Controls	Monitor CO as the surrogate using a Continuous Emissions Monitoring System (CEMS).

7.0 DISPERSION MODELING

A dispersion modeling analysis was performed using the EPA and NHDES approved AERMOD model, to demonstrate that the combined emissions from the Facility will result in air quality impacts that are below EPA's Significant Impact Levels (SILs) and allowable PSD increments. The modeled impacts from the Facility were added to regional background values to demonstrate compliance with the NAAQS and NH AAQS. As discussed further below, modeling was also conducted to demonstrate that the Facility will not result in significant adverse impacts to other Air Quality Related Values (AQRV) including visibility, vegetation and soils, and sulfate and nitrate deposition. All of the modeling input and output files have been provided to NHDES electronically on a CD-ROM.

7.1 Source Emissions and Stack Data

The proposed Facility will include a biomass boiler, diesel engine powered fire pump and a wet cooling tower. The boiler and cooling tower will be permitted for unrestricted operation. The fire pump will be limited to no more than 500 hours of operation per year. Other than one hour per week for maintenance and testing, the fire pump will not operate concurrently with the boiler.

The fire pump is exempt from Env-A 1211.11 because it will be limited to less than 500 hours of operation, and 25 tons of NO_X emissions, in any 12-month consecutive period. However, to fully satisfy the requirements of the PSD Program, and assure a complete analysis of potential air quality impacts, the fire pump has been included in the dispersion modeling analysis conducted for the Facility.

Figure 1 presents the site location and Project area on a USGS topographic map. Figure 2 provides a Site Plan showing the location of all major components of the Facility. The 320 foot tall, 11.25-inch ID boiler stack is located at UTM coordinates 326,984 meters east, 4,926,531 meters north, [Zone 19, North American Datum (NAD) 83]. The height and inside diameter of the existing boiler stack were determined from design drawings, which have been included in Appendix C. The closest property boundary is approximately 150 feet south of the existing boiler stack.

Table 7.1 presents the exhaust gas characteristics of the boiler at various operating conditions, along with the dimensions of the exhaust stack. Exhaust parameters are presented for operation of the boiler at full load with fuel moisture contents of 37.6% and 50%, and for 70% (minimum) load with fuel moisture contents of 37.6% and 50%. The biomass boiler will not operate at steady-state at loads less than 70% of maximum load, except for during periods of startup and shutdown. The emissions from the biomass boiler were modeled at these fuel moisture contents because this is the expected range of the moisture content of the wood fuel for the Facility. In addition, the boiler was modeled at two different stack temperatures per operating scenario, in order to assess the impacts from the boiler under a potential operating condition where a portion of the heat from the exhaust gas stream is recovered by a heat exchanger.

As noted on Table 7.1, all of the emission rates from the boiler have been increased by a factor of 10% for the short-term (24 hours or less) impact analyses, to account for expected variability in the exhaust gas volumetric flow rate from the boiler. The annual impacts resulting from boiler operation have not been increased by this 10% factor, as the expected variability in exhaust gas volumetric flow rate will average out to the emission rates derived using heat input rate emission factors over an extended period of time.

Table 7.1a presents the stack parameters and emission rates for the boiler during startup events, which are discussed further in Section 7.15 below. All conditions and emission rates for the boiler were provided by Babcock & Wilcox, the vendor of the Bubbling Fluidized Bed Technology to be installed in the unit.

Exhaust characteristics and stack dimensions for the fire pump are also presented in Table 7.1. The cooling tower emissions are summarized on Table 7.2.

7.2 Dispersion Environment

Land use within a three-kilometer radius of the Facility was classified in accordance with the NHDES recommended method (Auer, 1978). This classification is necessary to determine if the modeled source is urban or rural. Urban sources require additional inputs to AERMOD. Information contained on USGS topographic maps was sufficient to determine that the area within three kilometers of the Site is predominantly rural. Therefore, rural dispersion coefficients were used in the screening modeling analysis.

7.3 Good Engineering Practice (GEP) Stack Height Determination

US EPA regulations establish limitations on the stack height that may be used in dispersion modeling to calculate air quality impacts of a source for regulatory purposes. Each source must be modeled at its actual physical height unless that height exceeds its calculated Good Engineering Practice (GEP) stack height. If the physical stack height is less than the GEP formula height, the actual stack height is input to the model and the potential for the plume to be affected by aerodynamic wakes created by nearby buildings must be evaluated in the dispersion modeling analysis.

A GEP stack height analysis was performed in accordance with the procedures set forth in the EPA guidance document "Guideline for Determination of Good Engineering Practice Stack Height" (EPA, 1985). A GEP stack height, as measured from the base elevation of the stack, is defined as the greater of 65 meters (213 feet) or the formula height (Hg) determined from the following equation:

$H_g = H + 1.5L$

where

H = height of the nearby structure which maximizes H_g

L = lesser dimension (height or projected width) of the building

The GEP formula height is based on the dimensions of buildings "nearby" the stack that result in the greatest justifiable height. For the purposes of determining the maximum GEP formula height, "nearby" is limited to the less of five building heights or widths from the trailing edge of the building (edge closest to the source).

The Facility structure heights are shown on Figure 3. The height and projected width of the structures used for the GEP analysis are shown in Table 7.3. The tiers are listed in descending order relative to the resulting formula GEP heights. The boiler house is the controlling structure for the boiler. The boiler building is a tall structure, 164.5 feet (50.1 meters) high, 118 feet (36.0 meters) wide and 84 feet (25.6 meters) long. The resulting GEP formula height is 381.8 feet (116.4 meters).

Since none of the proposed stack heights exceed the GEP height, assessment of building downwash in the modeling analysis is required.

7.4 Cavity Region

Buildings located near to stacks can create cavity regions which can trap the stack's emissions and result in locally high concentrations of air contaminants. The cavity region created by a building can extend out to three times the lesser of a building's height or its projected width. The cavity height can extend up to the structure height plus one-half the lesser of the structure height or projected width. Air quality impacts with the downwind cavity regions need to be analyzed when a stack's height is less than the cavity height.

As shown in Table 7.4, the boiler building results in the highest cavity height and greatest cavity region extent. The cavity region created by the 164.5 foot tall boiler building extends 434 feet from the structure and 237 feet above the ground. The closest fence line to the boiler building is approximately 200 feet to the south. The cavity region from the 164.5-foot structure has the potential to extend beyond the fence line and, therefore, is located in ambient air. Even though the boiler stack is above the calculated cavity height, cavity impacts were included in the modeling analysis in order to assure a complete assessment.

7.5 Local Topography

Local topography plays a role in the selection of an appropriate dispersion model. Dispersion models can be divided into two categories: (1) those applicable to areas where terrain is less than the height of the top of the stack (simple terrain), and (2) those applicable to areas where terrain is greater than the height of the top of the stack (complex terrain). The closest complex terrain is located approximately 900 meters from the boiler stack.

7.6 Models Selected for Use

The dispersion environment, potential of aerodynamic building downwash effects on ground-level concentrations, and the local topography help to determine the appropriate models for use in a dispersion modeling analysis. Simple terrain models are used to calculate concentrations in simple terrain (below stack-top elevation) and intermediate terrain (up to plume height). Complex terrain models are used to calculate concentrations in complex terrain (above stack-top elevation).

Based on stack heights that are less than the GEP formula height and terrain above the stack top elevation within eight kilometers of the stacks, preliminary screening modeling was performed with EPA's SCREEN3 (dated 96043) model. If the results of the conservative SCREEN3 model do not predict compliance with applicable standards and additional modeling is necessary, the preferred model is the EPA AERMOD model for both simple and complex terrain.

SCREEN3 can be applied to predict 1-hour, ground-level calculations for single sources. The model incorporates the effects of building downwash in both the cavity and wake regions (areas of plume downwash beyond the cavity region). The SCREEN3 model calculates 1-hour concentrations in simple terrain using algorithms from the US EPA Industrial Source Complex model, ISCST3. For complex terrain elevations, the SCREEN3 model calculates a 24-hour concentration using the VALLEY model. The VALLEY model concentrations are based on six hours of persistent meteorological conditions, and allow the plume to come no closer than 10 meters to the ground. The SCREEN3 model also makes an ISCST3 calculation for intermediate terrain receptors. Intermediate terrain receptors have elevations that are greater than stack-top elevation but less than plume height. The higher of the VALLEY and ISCST3 calculations is used in the screening results.

As discussed further below, following application of the SCREEN3 model, the US EPA AERMOD model was used as a refined tool to evaluate any pollutants and averaging periods for which SCREEN3 modeling yielded results above the SILs. AERMOD was used to calculate maximum 1-hour average ground-level concentrations at all receptor locations, including offsite locations within the cavity region, from which it determined block averages for the other required averaging periods. AERMOD is a refined model that can be applied to consider actual meteorological in the project area and the potential building downwash effects on ground-level concentrations and to estimate concentrations in either simple or complex terrain.

There are two nearby Class I areas. The Facility is located approximately 18.1 kilometers north of the Great Gulf Wilderness Area, and 26.0 kilometers north of the Dry River Wilderness Area. CALPUFF is a long-range transport model developed to evaluate impacts beyond 50 kilometers. The Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report recommended the use of CALPUFF for transport distances of 200 km and less, to eliminate the need to simulate the long-range impacts (greater than 50 km) separately, and then combine these results with those obtained using some other model for the local-scale impacts (less than 50 km). Because the Class I areas are within 50 kilometers of the Facility, long-range modeling was not required to determine the Class I impacts from the Facility, so AERMOD, an appropriate model for local-scale impacts was used.

7.7 Preliminary Screening Model Application

The SCREEN3 dispersion model was applied in accordance with the recommendations made in EPA's "Guideline on Air Quality Models" (EPA, 2003) to assess the magnitude of maximum pollutant concentrations from the Facility sources. SCREEN3 was applied using rural dispersion parameters, default meteorology, building downwash and terrain elevations. The model was applied for the full set of 54 default meteorological conditions that accompany the model and encompass all atmospheric stability classes and a range of wind speeds. The screening meteorological conditions are presented in Table 7.5. Default mixing heights are dependent upon the wind speed. The SCREEN3 mixing heights are presented in Table 7.6. Table 7.7 presents the distances and terrain elevations used in the SCREEN3 simple terrain analysis.

Simple terrain screening receptors were located along a single radial. Receptors were placed at 100-meter spacing out to 2 kilometers, 200-meter spacing out to 4 kilometers, 500-meter spacing out to 10 kilometers, 1-kilometer spacing out to 20 kilometers, and 5-kilometer spacing out to 50 kilometers.

AERMAP was used to assign receptor elevations for given distances, over all compass directions. The closest complex terrain receptor is located 0.9 kilometers from the Facility. For the simple terrain screening analysis, the stack-top elevation was assigned as the receptor elevation for all distances beyond 0.9 kilometers. SCREEN3 receptor terrain height values are based on the difference between the actual terrain elevation and the stack base elevation (1041 feet mean sea level).

Table 7.8 presents the terrain elevations and distances used in the SCREEN3 complex terrain screening analysis and determined using AERMAP, as discussed further below. The complex terrain receptors were based on the closest distance to the boiler stack for which elevations ranging from stack-top to the maximum elevation found within 50 kilometers. The closest complex terrain is found 0.9 kilometers from the Facility, with elevations extending to 1326 meters above stack-base elevation at 19 kilometers.

The SCREEN3 model calculates one-hour concentrations at simple terrain locations. The model calculates 24-hour concentrations in complex terrain. The VALLEY complex terrain concentrations are based on six hours of persistent meteorological conditions.

NAAQS have been established for various averaging periods. Short-term 1-hour and 8-hour standards have been established for carbon monoxide (CO). An annual standard and a 1-hour standard have been established for nitrogen dioxide (NO_2). Annual, 3-hour, and 24-hour standards have been established for sulfur dioxide (SO_2). Annual ($PM_{2.5}$) and 24-hour (PM_{10} & $PM_{2.5}$) standards have been established for particulate matter. To estimate concentrations for each averaging period, scaling factors of 0.9, 0.7, 0.4, and 0.08 were applied to the 1-hour averages predicted by the SCREEN3 model to derive 3-hour, 8-hour, 24-hour, and annual average estimates.

The 24-hour average complex terrain results were first scaled to one-hour concentrations using a scaling factor of 4.0. The same scaling factors described above were then applied to the 1-hour estimates to obtain estimates for averaging periods other than the 24-hour average.

A simple terrain screening modeling analysis, a complex terrain screening modeling analysis and a cavity screening analysis were performed using the SCREEN3 model for the flue gas characteristics of the proposed boiler at each load condition. The cooling tower and fire pump were also evaluated with SCREEN3. Screening modeling was performed to determine the worst-case short-term and long-term operating conditions for each modeled pollutant.

Table 7.9 presents the maximum impact concentrations predicted by the SCREEN3 model for each potential normal operating load condition for the boiler and from the cooling tower and fire pump in Class II areas (impacts determined during boiler startup events are discussed separately in Section 7.15 below). Table 7.9a presents the maximum impact concentrations predicted by SCREEN3 in Class I areas. In each instance, the actual 1-hour average impacts predicted for each pollutant were determined by scaling the unit emission rate (i.e. 1 gram per second) normalized 1-hour concentrations by the maximum equipment emission rates presented in the tables. To estimate concentrations for other averaging periods, scaling factors discussed above were applied to the one-hour averages, along with the following operating limitations. The impact concentrations presented in Table 7.9 do not reflect any annual or short-term operating limits for any of the sources.

Table 7.10 presents a summary of the maximum predicted SCREEN3 impact concentrations as determined from the complete set of SCREEN3 results presented in Table 7.9 from each of the modeled sources in Class II areas. As determined from review of results provided in Table 7.9, the maximum boiler impact concentrations result at 100% load with heat recovery and with fuel moisture contents of 37.6% in simple terrain and 50% within the cavity region and in complex terrain. These impacts are predicted to occur in simple terrain at a distance of 900 meters. This represents the closest stack-top elevation to the boiler stack. The highest modeled screening concentrations in complex terrain are predicted to occur at a distance of 1400 meters from the boiler stack.

Table 7.10a presents a summary of the maximum predicted SCREEN3 impact concentrations as determined from the complete set of SCREEN3 results presented in Table 7.9a from each of the modeled sources in Class I areas. Similar to the Class II SCREEN3 results, the maximum boiler impact concentrations are predicted at 100% load with heat recovery. The worst-case fuel moisture content is 50% in both simple complex terrain, slightly greater than the 37.6% fuel moisture content impacts. Both 50% and 37.6% fuel moisture contents were evaluated in the AERMOD analysis.

Annual impact concentrations for the individual sources are based on the annual operating limits; unrestricted operation for the boiler and cooling tower, and 500 hours the fire pump. These operating limits were used to determine the annual average emission rate for each pollutant from each source, which was then applied to the unit emission rate impacts to predict the annual average pollutant impacts. The total annual impacts concentrations shown in Tables 7.10 and 7.10a are based on the sum of the maximum values for the boiler, cooling tower and fire pump.

Short-term averages (24 hours and less) are based on the following operating limitations: the boiler and cooling tower will be unrestricted and, other than one hour per week for maintenance testing, the fire pump will not operate concurrently with the boiler. The total short-term concentrations shown in Tables 7.10 and 7.10a are based on the sum of the maximum values for the boiler and cooling tower, and the 1-hour average impacts from the fire pump.

The total estimates are conservative in that all sources were assumed to have maximum impacts at the same location and with the same meteorological conditions. The individual source and potential total concentrations are compared to the SILs in Tables 7.10 and 7.10a. As shown in the tables, conservatively determined screening values are greater than the SILs in both Class I and Class II areas for:

- Annual NO_2 ,
- 3-hour, 24-hour and annual SO_2, and

- 24-hour and annual PM_{10} and $PM_{2.5}$.

The SCREEN3 results also identified the worst-case operating condition for the boiler. As discussed below, refined modeling was then undertaken to demonstrate the emissions associated with the Facility will result in impacts that are less than the SILs.

7.8 Preliminary Refined Modeling for Significant Impact Areas

A preliminary refined AERMOD modeling analysis was performed to determine the Significant Impact Area (SIA) of the Facility.

Meteorological data was collected by Fraser Paper in 1999 at the Burgess Mill Site, the location of the Facility. This data was supplied by NHDES (NHDES, 2009) and supplemented with surface observation data from nearby National Weather Service locations. These surface data were input to AERMOD with concurrent upper air data from Gray, Maine.

The Facility will utilize the existing 320-foot tall boiler stack, which serviced the former Recovery Boiler at the site. As such, ESS and NHDES agreed that the wind speed and direction data collected from the 100-meter high station of the Burgess Mill tower, coupled with other parameters collected from the tower, and supplemented with data from other regional monitoring stations to fill in missing data and upper air parameters, could provide a suitable meteorological data set for Facility modeling purposes (ESS, 2009). The final meteorological data set was compiled using the following methodology:

1. The temperature data and 100-m level wind data collected in 1999 from the Burgess Mill tower were used as the primary data set.
2. Temperature and wind data missing from the Burgess Mill data set was replaced with data from other substations using the following hierarchy:
    1) Burgess Mill 70-m level,
    2) Berlin Municipal Airport, and
    3) Whitefield Airport.

Based on NHDES' approval of this approach, ESS worked to prepare the MET data set as discussed below.

There are 244 hours where wind speeds were missing from the Burgess Mill 100-m data, of which 134 hours were replaced with 70-m level data, 107 hours from the Berlin Airport, and 1 hour from the Whitefield Airport. There were 243 hours of missing wind direction data from the Burgess Mill 100-m data, of which 133 hours were replaced with 70-m level data, 101 hours from the Berlin Airport, and 6 hours from the Whitefield Airport. The wind rose for this data is shown in Figure 1.

There were 81 hours where temperatures were missing from Burgess Mill data set. Berlin Airport observations were available to provide data for 72 of those hours.

The standard deviation of wind direction and temperature difference data were also collected at the Burgess Mill. These parameters can be used within AERMET to provide better estimates of boundary layer conditions than simply using standard National Weather Service data. There are 246 hours where standard wind deviation data was missing from the 100-m level of the Burgess Mill data set. Of this total, 134 hours can be replaced with wind deviation data from the 70-m level. The remaining hours were input to AERMET as missing.

Cloud cover and ceiling height observations were collected at the Berlin Airport. There were 412 hours of missing data, of which 160 hours could be replaced with observations from the Whitefield Airport.

The EPA guidance document "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models" (EPA, 1992a) was followed for the remaining missing hours for which a valid substitution was not available from a regional monitoring station.

AERMET allows for the use of sectors to define land use within one kilometer of the meteorological data measurement location, classifying them among urban and rural categories. Sectors were determined for similar land use types. Land uses within one kilometer of the Burgess Mill are shown in Figure 1. Sectors for input to AERSURFACE and AERMET were defined as:

- 0-110 degrees (coniferous forest)
- 110-200 degrees (deciduous forest)
- 200-290 degrees (other cleared, residential/commercial), and
- 290-360 degrees (residential/commercial and transportation).

These sectors were input to AERSURFACE, an EPA program to compute surface roughness, albedo and Bowen ratio values to input to AERMET. The program follows EPA guidance presented in the "AERMOD Implementation Guide" (EPA, 2009) in developing the values. Surface roughness values were based on an inverse-distance weighted geometric mean for an upwind distance of one kilometer. Bowen ratio and albedo values were based on an arithmetic mean within a 10-km by 10-km area. The program was applied using average moisture conditions and winter snow cover.

7.9 Class II Impacts

A polar grid was centered at the existing boiler stack. Radials were placed from 0 degrees to 350 degrees at ten-degree increments. The proposed receptor grid was established to assure that these areas of maximum impact as determined from the SCREEN3 modeling were sufficiently covered in the refined modeling. Based on screening, the maximum SIA distance occurs for NO_X and extends 10 kilometers from the boiler stack. Receptor coverage was provided beyond the 10-km distance.

Receptor rings were located at:

- 50-meter increments out to 500 meters,
- 100-meter increments out to 2 kilometers,
- 200-meter increments out to 4 kilometers,
- 500-meter increments out to 10 kilometers, and
- 1-kilometer increments out to 15 kilometers.

NHDES requested that additional receptors be placed just beyond the western property boundary with 20-meter spacing to ensure that the maximum impacts from the cooling tower were determined. Receptors were placed at 20-meter increments out to 100 meters along the entire property boundary.

The Project Site will be fenced over its entire perimeter. The rail spur shown on the Site Plan will be accessed only by employees and the rail line operator. Recreational trails may be place just inside the property line along the river bank and Hutchins Street to allow for public access along these corridors. The perimeter fence line will run these corridors and the plant property to limit public access only to the designated pathway. Receptors were added to evaluate potential air quality impacts at locations extending onto the site within 100 feet of both the river bank and Hutchins Street.

The maximum terrain elevation and hill height were assigned for each receptor through the application of AERMAP. National Elevation Data (NED) data was input to AERMAP. The data was downloaded from the USGS website (http://sea,less.usgs.gov/index.php) and covered the area between 43.875 and 45.125 degrees north, and 70.375 and 72.0 degrees west.

AERMOD was run for the biomass boiler at the operation conditions identified by SCREEN3 as the worst-case for ambient impacts, 100% load at both 37.6% and 50% fuel moisture content with heat recovery.

Each source was modeled individually with a 1.0 gram per second emission rate. As was done with the SCREEN3 results, individual source pollutant concentrations were determined by multiplying the source emission rate for the applicable averaging period by the modeled unit emission rate impact. Refined concentrations from the individual sources were initially evaluated to examine potential cavity impacts and potential cumulative impacts.

Annual impact concentrations for the individual sources were based on the unrestricted operation of the boiler and cooling tower, and 500 hours for the fire pump. The annual total concentrations were based on the sum of the maximum values for the boiler, cooling tower and fire pump.

Short-term averages (24 hours and less) were based on the unrestricted boiler and cooling tower operation. Other than one hour per week for maintenance testing, the fire pump will not operate concurrently with the boiler. The total short-term concentrations were based on the sum of the maximum values for the boiler, cooling tower and one hour from the fire pump.

The predicted maximum impacts for each individual source and the potential maximum total impact concentrations presented in Table 7.11 are compared to the SILs for those receptors in the Class II area located outside of the perimeter of the site. The maximum potential impact concentrations for those receptors placed along the potential recreational corridors are shown in Table 7.11a and also compared to the SILs. The total estimates are conservative in that all sources are assumed to have maximum impacts at the same location and time. As determined from review of the results in both Tables 7.11 and 7.11a, the potential impacts for all pollutants and averaging periods in all of the publicly accessible Class II area are less than the SILs.

7.10 Class I Impacts

A preliminary refined AERMOD modeling analysis was also performed to evaluate potential impacts from the Facility to the closest Class I areas. The Class I analysis used the same data and methodology as the Class II AERMOD analysis.

The Project Site is located 18 kilometers north of the Great Gulf Wilderness Area, and 26 kilometers north of the Dry River Wilderness Area. Receptor locations and elevations were downloaded from the National Park Service website (www.nature.nps.gov/air/Maps/Receptors/index.cfm). The Class I receptor locations were converted from the NAD27 to the NAD83 UTM coordinate system for the analysis. Hill heights were assigned for each receptor using an anchor location in NAD83 through the application of AERMAP.

AERMOD was run for the biomass boiler at the operation conditions identified by SCREEN3 as the worst-case for ambient impacts, 100% load at 50% fuel moisture content with heat recovery, and also 37.6% fuel moisture content with heat recovery. Each source was modeled individually with a 1.0 gram per second emission rate. As was done with the Class II results, individual source pollutant concentrations were determined by multiplying the source emission rate for the applicable averaging period by the modeled unit emission rate impact. Refined concentrations from the individual sources were initially evaluated to examine potential cavity impacts and potential cumulative impacts.

Annual impact concentrations for the individual sources were based on the unrestricted operation of the boiler and cooling tower, and 500 hours for the fire pump. The annual total concentrations were based on the sum of the maximum values for the boiler, cooling tower and fire pump.

Short-term averages (24 hours and less) were based on unrestricted boiler and cooling tower operation. Other than one hour per week for maintenance testing, the fire pump will not operate concurrently with the boiler. The total short-term concentrations were based on the sum of the maximum values for the boiler, cooling tower and one hour from the fire pump.

The individual source and potential total concentrations presented in Table 7.12 were compared to the Class I SILs, which were provided by NHDES for use in this analysis (NHDES, 2010a).

As shown in Table 7.12, the results of the Class I refined modeling indicates that the potential impacts for 3-hour and 24-hour $PM_{2.5}$ exceed the Class I SILs. Initial modeling for the Facility showed the significant impacts are predicted to occur out to 34 kilometers for SO_2, and out to 40 kilometers for 24-hour $PM_{2.5}$. Since the initial modeling was performed, proposed SO_2, $PM_{2.5}$ emission rates have been decreased, resulting in smaller significant impact areas.

The major source increment baseline date for SO_2 is January 6, 1975 for all counties in New Hampshire. The major source increment baseline date for $PM_{2.5}$ is being triggered with this permit application. As the maximum Class I impacts are greater than the SO_2 and $PM_{2.5}$ SILs, the emissions from the Facility were modeled along with other background increment-consuming SO_2 sources within the Significant Impact Area (SIA) to demonstrate that the total SO_2 and $PM_{2.5}$ impacts resulting from all significant sources within the SIA will not exceed their respective PSD thresholds. NHDES provided the required data for other applicable SO_2 and $PM_{2.5}$ sources located within the SIA to facilitate the completion of this analysis (NHDES, 2010b). ESS conducted an independent review of the data and available data on regional air emissions sources that confirmed the information provided by NHDES and did not identify any additional sources that should be included in the analysis.

Table 7.12a presents the results of the Class I impact analysis. As shown in the table, emissions from the Facility, in combination with other increment consuming sources, result in modeled concentrations that do not exceed the allowable 24-hour $PM_{2.5}$ or 3-hour SO_2 increments.

7.11 Background Air Quality

When conducting an air quality impact analysis with respect to NAAQS, the existing background air quality in the absence of the proposed source must be considered in combination with the impacts resulting from the proposed source. When background air quality data is not available for the Project area, other representative background data from nearby monitoring stations must be used.

Background concentration data from nearby, representative monitoring stations for criteria pollutants during the most recent three years (2006-2008) were provided by NHDES. Table 7.13 provides a summary of the monitor values and background concentrations selected for use in the modeling analysis for the Facility.

7.12 PSD Increment Analysis

The maximum NO_2, PM and SO_2 impacts from the proposed Facility were assessed for increment consumption in both Class I and Class II areas. The Facility will have maximum impacts that are less than the SILs in Class II areas for all pollutants, thus demonstrating compliance with the respective PSD increments. As discussed in Section 7.10 above, the maximum SO_2 and $PM_{2.5}$ impacts in Class I areas exceed their respective SILs. , However, a cumulative modeling analysis demonstrated that the impacts from the Facility, when combined with the impacts from any other applicable increment consuming sources within the SIA, do not exceed their respective Class I PSD increments.

7.13 NAAQS Compliance Analysis

Maximum CO, NO_2, PM and SO_2 impacts from the proposed Facility were also assessed for compliance with the National Ambient Air Quality Standards (NAAQS). The Facility will have maximum Class II impacts that are less than the SILs. Table 7.14 presents the total concentrations, based on the sum of the Facility modeled concentrations and representative background concentrations. As shown on Table 7.14, the impacts from the Facility, combined with existing background concentrations, will not cause or contribute to an exceedance of NAAQS.

Since the date of filing the original air permit application for the Facility, a new 1-hour standard for NO_2 has come into effect. AERMOD was applied to determine compliance with the hourly NO_2 standard of 100 ppb. The 1-hour standard is based on the 3-year average of the 98^{th} percentile of daily maximum 1-hour values. The maximum 1-hour value at each receptor should be determined for each of day of the year, resulting in 365 or 366 concentrations. The 98^{th} percentile value is then the 8^{th} highest of these concentrations.

At the present time, AERMOD output can be used to determine the overall 8th highest modeled concentration at each receptor. However, the reported 8th highest values do not take the time period into account. Standard AERMOD output and post-processors do not directly handle the 8th highest of the daily maximum 1-hour values at this time. AERMOD output options can be used to generate the information needed to properly process the values.

EPA has recently issued guidance regarding AERMOD application for the 1-hour NO_2 standard (EPA, 2010). AERMOD should be applied with the POSTFILE option for each individual year of meteorological data, creating a concentration file containing modeled values for each receptor location and modeled hour. This file can then be read to determine the maximum 1-hour value at each receptor location and modeled day. The 8th highest modeled concentration is averaged at each receptor location over the 5-year modeling period. The highest of these 5-year averages should be added to regional background to determine a total concentration for comparison to the 1-hour NAAQS. In this analysis, one year of onsite meteorological data was used in lieu of as 5-year data set from a nearby airport.

AERMOD modeling was performed for the 1-year modeling period following the above guidance with one exception. The PLOTFILE option was applied to output the ten highest modeled concentrations for each year at each receptor location. The highest ten values were evaluated in order to be able to to determine the eight highest values occurring on different days.

Table 7.15 presents the results of the 1-hour NO_2 NAAQS analysis. For this analysis, post-processing was not necessary. The overall highest of the 8th high (H8H) 1-hour concentrations, without regard to daily maximum values, were sufficiently low to demonstrate compliance with the 1-hour NO_2 NAAQS. The 98th percentile concentrations presented below are the H8H values presented in the AERMOD output, without regard to the day they occur.

The maximum 98th percentile average NO_x concentration from the biomass boiler and fire pump is 81.7 µg/m^3. NHDES provided a 1-hour background value of 53 µg/m^3, from 2000-2002 Brentwood monitoring data. Adding the maximum of the 98th percentile daily maximum NO_x values to the background results in a total NO_x concentration of 134.7 µg/m^3), that is less than the 1-hour NO_2 standard of 100 ppb (188.6 µg/m^3).

Modeling was also performed for a set of potential public access receptor locations that are within the site boundaries. The maximum 98th percentile average NO_x concentration from the biomass boiler and fire pump is 73.7 µg/m^3, modeled at UTM coordinate 326925, 4926608. Adding the maximum of the 98th percentile daily maximum NO_x values to the background results in a total NO_x concentration of 126.7 µg/m^3, that is less than the 1-hour NO_2 standard.

7.14 Regulated Toxic Air Pollutants

NHCAR Chapter Env-A 1400 establishes rules to prevent, control, abate and limit the emissions of toxic air pollutants into the ambient air to promote public health. All stationary sources in New

Hampshire that emit a regulated toxic air pollutant are subject to this regulation, except for specified exempt sources and activities. One of the source categories which are exempt from the requirements of the rule is the combustion of untreated wood. Therefore, the emissions from the biomass boiler are not subject to the state regulated toxic air pollutants rule requirements. The fire pump will not emit a regulated toxic air pollutant at a rate that is above either its annual or 24-hour de minimis emissions level. These sources are therefore not subject to the rule.

There will be emissions of NH_3 from the SCR emissions control system. Additionally, the use of certain water treatment chemicals in the cooling towers will result in the emission of 'free chlorine' (as part of the cooling tower drift) above de-minimis emission rate levels of Env-A 1400. However, the air dispersion modeling analysis conducted for the Facility demonstrates that the maximum predicted ambient air impacts for NH_3 and free chlorine, at or beyond the property line, are less than the 24-hour and annual ambient air limits (AALs) established in Table 1450-1 of NHCAR Chapter Env-A 1400. The Facility will therefore comply with the NH Regulated Air Toxics rule. Table 7.15 summarizes the results of the RTAP analysis conducted for the Facility.

7.15 Boiler Startup Modeling

An air quality impact analysis was also performed to evaluate a cold startup scenario for the biomass boiler. According to the information provided by the vendor, a cold start will typically take approximately 12 hours. During the first 8 hours, the oil-fired startup burners will be operated up to their full capacity (240 MMBtu/hr) to heat up the bed material and boiler heat transfer surfaces. The biomass feed will then begin and gradually be increased over a 3 hour period, with the firing rates of the oil burners gradually decreased. When the boiler reaches approximately 50% of its steam capacity, the oil burners will no longer be in operation and the wood feed rate will be increased over an additional 1 hour period to achieve the minimum operating steady state load of 70% at which point the startup cycle will be completed. It is estimated that there will be up to six cold startups of the biomass boiler per year.

Other than one hour per week for maintenance testing, the fire pump will not operate concurrently with the boiler. Maintenance testing will not be performed during boiler startups so the fire pump was not included in the short term impact analyses for cold startup periods. The cooling tower will be in operation during startup periods so the cooling tower emissions were included in the startup modeling analysis.

The expected boiler startup emissions and exhaust parameters are summarized on Table 7.1a for each startup phase. SCREEN3 was applied to evaluate the three start-up phases using the same methodology as was applied for normal boiler operation. The results of the SCREEN3 Class II analysis for the boiler cold startup operating scenario are presented in Table 7.16 for simple terrain, complex terrain and cavity impacts.

Annual impacts were based on 6 cold starts per year. Short-term impacts were based on the length of time for each phase. The highest CO impacts occur during Phase 1. Since Phase 1 lasts for 8 hours, the maximum Phase 1 CO impacts were used to evaluate the maximum 1-hour and 8-hour CO impacts in comparison to the SILs. The maximum 1-hour SO_2 impacts were predicted during Phase

2. Since Phase 2 lasts for three hours, the maximum Phase 2 SO_2 impacts were used to evaluate the maximum 3-hour SO_2 impact in comparison to the SIL. The maximum 24-hour SO_2, PM_{10} and $PM_{2.5}$ impacts and the maximum annual NO_2, SO_2, PM_{10} and $PM_{2.5}$ impacts were based on the cumulative impacts of Phase 1 (8 hours), Phase 2 (3 hours), Phase 3 (1 hour) and the maximum combined facility impact during normal operation (previously determined by refined modeling) for the remainder of the averaging period.

A summary of the Class II SCREEN3 combined impacts from startup and normal operation are summarized in Table 7.17. The maximum 24-hour and annual impacts from normal Facility operation were added to the startup impacts to determine the potential total Facility impact concentrations. This methodology was conservative because the 24-hour and annual boiler impacts during normal operation were not adjusted to account for reduced normal operation due to startups. Based on the SCREEN3 results, total impacts greater than the SILs were determined for 8-hour CO, 24-hour PM_{10} and 24-hour $PM_{2.5}$.

AERMOD was then applied using a 1 gram per second emission rate to determine the maximum 8-hour Phase 1 impact concentration, the maximum 3-hour Phase 2 impact concentration, the maximum 1-hour Phase 3 impact concentration and the maximum 12-hour normal operation (boiler and cooling tower) impact concentration. These normalized values were multiplied by the PM_{10} and $PM_{2.5}$ emission rates and summed, without regard to location or time, to conservatively estimate the maximum potential 24-hour combined impact concentrations. The results of this AERMOD analysis are presented in Table 7.18. As shown in Table 7.18, the maximum 8-hour CO and 24-hour PM_{10} impacts are less than the SILs. Additional refined modeling was then performed to demonstrate that the maximum 24-hour $PM_{2.5}$ impact concentration resulting from cold boiler startups would also be less than the SIL.

AERMOD was applied using the $PM_{2.5}$ emission rates for the three cold startup phases and during normal operation to determine the maximum potential 24-hour $PM_{2.5}$ concentration. As a cold startup could commence anytime during the day, 24 scenarios were evaluated. The 24 scenarios were based on Phase 1 starting at each hour of the day, and lasting for 8 hours. Phase 1 was immediately followed by 3 hours of Phase 2, which was then followed by 1 hour of Phase 3. The boiler and cooling tower were assumed to be operating at normal load during the hours each day preceding Phase 1 and following Phase 3. These scenarios were modeled for the boiler during normal operation at both the 50% and 37.6% fuel moisture contents. The results of the twenty-four $PM_{2.5}$ AERMOD runs are presented in Table 7.19. As shown in Table 7.19, the maximum predicted 24-hour $PM_{2.5}$ concentration was 1.4 ug/m^3, less than the SIL of 2 ug/m^3.

The boiler startup modeling analysis demonstrated that the maximum ambient air quality impacts resulting from cold startups of the boiler will all be below their respective SILs.

7.16 Visibility Impacts

7.16.1 Class I Areas

Initial VISCREEN modeling indicated that plume from the biomass boiler associated with Laidlaw Berlin BioPower Facility may be visible within the Great Gulf Wilderness Area, based on the modeled delta-e values. This initial VISCREEN modeling was based on the maximum boiler emission rates and model default values. The worst-case values were determined to occur with a wind speed of 1.0 meter per second and when the plume is visible at a low angle, shortly before or after sunrise.

Air Resources Specialists, Inc. (ARS) reviewed the initial VISCREEN modeling on behalf of the United States Forest Service. ARS requested additional modeling to determine the frequency of occurrence of the meteorological conditions leading to a visible plume. As with the initial modeling, inputs included:

- Maximum boiler emission rates; 1.40 g/sec PM, 8.42 g/sec NO_x
- Background range = 60 km
- Minimum distance to Class I area = 18.1 km
- Maximum distance to Class I area = 24.0 km
- Defaults for other emission rates, particle characteristics, background ozone and observer angle.

The default meteorological condition for the model is very stable (stability class F) and 1.0 meter per second wind speed. To determine the full extent of potential plume visibility, additional model runs were performed for stability classes D, E and F, increasing the wind speed from 1.0 meter per second until the delta-e screening criteria was met within the Class I area.

The modeled wind speed and stability class combinations, along with the resultant delta-e values are presented in Table 1. Initial modeling demonstrated the potential for a visible plume with stability class F and a wind speed of 1.0 m/sec. However, the screening criteria were not exceeded for stability class F and a wind speed of 2.0 m/sec. Additional runs were performed using the on-site meteorological data collected in 1999 to determine that the modeled delta-e is less than the screening criteria at wind speeds equal to or greater than 1.3 m/sec as shown in Table 1. Additional model runs also confirmed that the delta-e screening criteria were met for stability classes D and E with the 1.0 m/sec wind speed.

Based on these results, the only periods during which the plume may be visible within the Class I area are limited to F-class stability conditions and wind speeds equal to or less than 1.2 m/sec. As discussed below, the on-site meteorological data set was further analyzed to determine the frequency of conditions meeting these criteria, and occurring during early morning hours with the wind blowing toward the class I area.

AERMOD was used in the dispersion modeling to determine compliance with the NAAQS. AERMOD does not directly use stability classes as the ISCST3 model did. As such, PCRAMMET was applied to generate an ISCST3 meteorological data set that included stability class. The hourly stability class values were combined with the on-site wind speeds and flow vectors. The flow vector is the direction toward which the wind is blowing, 180 degrees off of the wind direction. The Class I area is located between 18.1 and 24.0 kilometers south of the stack, at directions 197 through 212 degrees.

The 1999 meteorological data base was screened to include the following conditions:

- Wind speed = 1.2 or less
- Flow vectors of 185 to 225 degrees (wind sectors 19-22), to include sectors 10 degrees outside of the Class I area
- Stability class F

A total of 130 non-calm hours were observed during 1999 that met the above conditions, regardless of the time of day. The longest consecutive time period meeting these conditions was 3 hours.

The model predicts a visible plume when the sun angle is low. Therefore, these hours were further screened to include only hours just before or after sunrise. Evaluating hours ending at 5 AM through 8 AM, 31 hours occur on 26 different days were identified that meet the specified modeling criteria. As such, the potential for visible plume impacts are less than 1% of total annual daylight hours.

These hours are presented in Table 2, along with the corresponding transport times to the Class I area. As shown in Table 2, 20 of the 31 hours are associated with very low wind speeds (0.5 m/second and less) that result in transport times of 10 hours or more. However, as such conditions are only sustained for periods of 3 hours or less it is very likely that the plume has broken up before even getting to the Class I area. The shortest transport time is 5 hours.

7.16.2 Class II Areas

Local visibility impacts resulting from the operation of the Facility sources will be minimal. The opacity of the plume from the biomass boiler will be maintained at levels of no greater than 10% and under most operation should not be readily apparent or block views of the surrounding areas. The boiler will be equipped with a COMS to continuously monitor compliance with the permitted state opacity limits.

The Facility's cooling tower will have a water vapor plume that will be periodically visible under certain atmospheric conditions that involve very cold temperatures, or high relative humidity and low wind speeds. Modeling of the cooling tower plume was conducted using the Seasonal Annual Cooling Tower Impact (SACTI) model developed by Argonne National Laboratories and commonly used to evaluate the behavior of cooling tower plumes. The results of the model indicate that operation of the cooling tower will not cause any conditions of ground level fogging or icing. The model further indicates that the average water vapor plume height will be about 56 feet above the cooling tower for an overall height of approximately 100 feet above ground level, which is shorter than the nearby boiler building height of 164 feet. The plume is predicted to rise above the height of the boiler building only about 5 hours per year, a condition that is most likely to occur when ambient relative humidity is very high and regional visibility is already obscured by fog or precipitation.

7.17 Impacts to Soils and Vegetation

The PSD regulations require an air quality impact analysis on sensitive types of soils and vegetation. The assessment was performed by adding the Facility impacts with ambient background concentrations and comparing the total to vegetation sensitivity screening levels presented in Table 3.1 of EPA's "A Screening Procedure for the Impacts of Air Pollution on Plants, Soils and Animals" (EPA, 1981). The screening levels represent the minimum screening levels at which visible damage or growth effects to vegetation may occur. Screening levels have been established for the following pollutants that will be emitted from the Facility:

- 1-hour, 3-hour and annual SO_2,
- 4-hour, 8-hour, monthly and annual NO_2,
- Weekly CO,
- Monthly beryllium, and
- Quarterly lead.

The proposed background air quality concentrations used in all modeling analyses for this Facility are based on 2005-2007 monitoring data. The highest annual averages over the three-year period were selected as the annual background values. Short-term background values (24-hours and less) were based on the highest of the yearly second-high values. The monitoring data is available on EPA's Aerometric Information Retrieval System (AIRS) internet site (www.epa.gov/aersweb). The closest lead monitoring location is at Kenmore Square in Boston. Monitoring data is not presented for beryllium. In addition, data found on the website is not presented for all averaging periods being examined. In those cases, the next shortest averaging period was used to conservatively estimate the background.

Background was conservatively estimated for:

- Use of 1-hour values for 4-hour, 8-hour and monthly NO_2, and
- Use of 8-hour CO values for weekly CO.

Refined AERMOD modeling was performed to determine individual source impacts from the boiler, cooling tower and fire pump. As shown in Table 7.20, the modeled concentrations from the Facility, in combination with representative background values, are less than the vegetation sensitivity concentrations. Therefore, the Facility will not adversely impact vegetation in the area.

7.18 Impacts to Growth

The construction and operation of the Facility will have a very significant, positive effect on the City and region. Its development will convert a Brownfield site with environmental issues that are a barrier to development into an asset for the City of Berlin that will foster additional economic development and rising employment. LBB is ready and willing to work with the City to acquire the balance of the former Pulp Mill site (i.e. the remaining 40 acres of land that were part of the Pulp Mill site and located immediately adjacent to the Project Site) and prepare it for redevelopment. LBB has offered its support for the formation of a nonprofit organization under Internal Revenue Code § 501(c)(3) to acquire the property and help guide a plan to redevelop it. With that redevelopment, economically diverse and beneficial projects could be located adjacent to the Site.

The Facility will provide for support and expansion of the local economic base. It will bring increased economic activity to the City and the region during construction and operation. Furthermore, the Facility will be a major addition to the tax base in the City of Berlin without burdening public services.

Construction of the Facility will inject approximately $80 million into the surrounding economy for the purchase of local goods and services such as such as earthwork, engineering, general construction services, specialized trades, construction materials and support services. The Facility will have substantial long-term economic benefits, including permanent direct employment for 40 people related to the operation of the Facility and indirect employment of up to 300 people for timber harvesting and processing, trucking, forestry consulting services, and mechanical services. LBB hopes to draw most of the Plant employees from the greater Berlin area. The Facility will provide increased commerce in the area from the purchases of local goods and services by the Facility and employees.

The Facility brings a new enterprise and diversity to the Berlin economy by shifting from the production of paper to renewable energy. LBB hopes to act as incubator for the development of new businesses that may be similarly involved in the clean energy sector. The plant is being designed to utilize "waste heat" which will be converted to hot water for use at the Fraser paper mill in Gorham. This feature offers the opportunity to help reduce fuel oil costs at the paper mill.

The Facility is compatible with and supportive of the forest industry in the region. It will provide a steady, dependable market for wood and in turn providing strong incentives for long-term commercial forestry management. The regional logging and trucking industries, as well as landowners, will be able to rely on this dependable market that will be largely insulated from fluctuations in global markets. The facility will spend between $20 million and $25 million per year on biomass fuel purchases and will seek to keep the purchase of the renewable timber supply in the immediate vicinity of the power plant.

7.19 Sulfate/Nitrate Deposition in Class I Areas

An analysis was performed to assess the potential for sulfate and nitrate deposition within Class I areas closest to the Berlin BioPower Project. The Great Gulf and Dry River Wilderness Areas are located approximately 18 and 26 kilometers south of the Project site, respectively.

AERMOD was used to perform the deposition modeling, as the Class I areas are less than 50 kilometers from the Facility. AERMOD includes algorithms for both wet and dry deposition of gaseous emissions. Inputs required for gas deposition modeling include seasonal definitions, and land use characteristics for the ten-degree wind sectors between the Facility and the Class I areas.

Nine land use categories are available for input:

1. Urban land, no vegetation
2. Agricultural land
3. Rangeland
4. Forest
5. Suburban areas, grassy
6. Suburban areas, forested
7. Bodies of water
8. Barren land, mostly desert, and
9. Non-forested wetlands

The Class I areas are located south-southwest of the Facility. The plume encounters mostly forested areas as it travels between the Facility and the Class I areas. Land use category 4 (forest) was chosen for the analysis.

The AERMOD surface file was populated with hourly precipitation data from collected from the meteorological tower previously located at the Project site for the year of data used for modeling (1999). Precipitation codes of 21 and 41 were assigned for hours when the ambient temperature was above freezing, and at freezing or below, respectively. These codes correspond to the present weather codes for moderate rain and snow found in the SAMSON and TD-3280 data files.

AERMOD was then used to evaluate both gaseous and particulate deposition rates in the Class I areas. The Facility's annual average emission rates of SO_2 and NO_x were adjusted to represent only the sulfur and nitrogen portions of the total emissions. The two pathways were modeled separately, with the results summed at each receptor location.

Gaseous deposition was evaluated using the following input parameters:

- Default reactivity factors and fractions of maximum green leaf area index (LAI),
- Diffusivity in air and water = 0.1509 cm^2/sec,
- Cuticular Resistance = 30 s/cm, and
- Henry's Law Constant = 0.04 (pa-m^3/mol).

Gaseous nitrate deposition was evaluated using the following input parameters:

- Reactivity factor = 0.1

- Default maximum LAI of 0.5 and 0.25 for seasons 2 and 5,
- Diffusivity in air and water = 0.1656 cm^2/sec,
- Cuticular Resistance = 30 s/cm, and
- Henry's Law Constant = 3.5 (pa-m^3/mol).

Method 2 was used to evaluate particle deposition with mass fraction of fine particles equal to 1, and a mass mean diameter of 1 micron.

The summed gaseous and particle deposition results are compared to the Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr, for both sulfates and nitrates. AERMOD output presents the deposition in units of g/m^2-year. The 0.01 kg/ha-yr DAT equates to 0.001 g/m^2-year.

The maximum modeled sulfate deposition from the Facility at any individual receptor location is 0.00058 g/m^2-year (0.0058 kg/ha-yr), about 60% of the DAT. The modeled sulfate deposition at 99% of the receptor locations is less than one-half of the DAT.

The maximum modeled nitrate deposition from the Facility is 0.00151 g/m^2-year (0.0141 kg/ha-yr), about 40% greater than the DAT. The modeled nitrate deposition level exceeds the DAT at only 9 of the 226 modeled receptor locations, indicating that predicted deposition levels are below the DAT at about 96% of all Class I area locations.

- These impacts also do not consider the following:
- The Facility is required to offset 115% of its NOx emissions, creating a net regional reduction in NOx emissions.
- The Facility's maximum potential NOx emissions are 266 tons per year lower than the annual NOx emissions that actually occurred from sources operating at the Project site in years prior to 2006.
- The impacts and DATs do not consider the significant regional NOx emissions reductions that expected with the upcoming implementation of the Clean Air Interstate Rule (CAIR), which will impact many large sources located upwind of the Class I areas.

Based on these considerations, Laidlaw does not believe that the Facility will result in significant adverse nitrate or sulfate impacts in the nearest Class I areas.

7.20 Environmental Justice

In 1994, President Clinton issued Executive Order 12898 "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations". Environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no group of people, including any racial, ethnic, or socioeconomic group, should bear a disproportionate share of any negative environmental consequences resulting from industrial and other commercial operations or the execution of federal and state programs and policies. Meaningful involvement means that potentially affected community residents have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health and that their contributions will be considered and may influence the regulatory agency's decision. Regulatory agencies are directed to seek out and facilitate the involvement of those potentially affected. As discussed below, the Berlin BioPower project meets all of the above requirements.

ESS performed an environmental justice assessment using the policy guidance and framework of the "Toolkit for Assessing Potential Allegations of Environmental Injustice" published by the US EPA. Based on a review of the most recent census data available, several communities in the City of Berlin were identified with greater than the state-wide average of low-income or minority populations. Although such populations may exist within the local community, the Facility results in neither a significant adverse impact nor a disproportionate impact to any group of residents. The air modeling discussed earlier in the application concludes that all air quality impacts in the community are below EPA established SILs and are therefore insignificant. The SILs are a small fraction of the NAAQS established by EPA to be protective of public health and the environment, considering the most vulnerable of the population, with a margin of safety. Thus, the Facility's air quality impacts are not significant or adverse. Further, as shown in Figures 7.1 and 7.2, the predicted 24-hour and annual ambient air quality impacts of fine particulate emissions from the Facility are fairly uniform through the City, are all well below the SILs, and do not result in significantly higher impacts in any one areas than another. Therefore, no portion of the community is disproportionally impacted.

The Facility is undergoing permitting the New Hampshire Site Evaluation Committee (SEC), which engages in a very public and transparent process. All of the proceedings associated with the SEC's review are publicly available. A Public Informational Hearing was held on March 16, 2010 in the City of Berlin to provide information to the public and allow their concerns to be heard. The SEC has appointed Counsel to the Public to represent the interests and concerns of the community. Several additional public meetings and hearings are scheduled to occur in Berlin over the coming months, including a public hearing specifically for the purpose of this air permit, that assure the public has multiple and readily accessible opportunities to participate and provide their input regarding the Facility. These aspects of the permitting process provide significant opportunities for meaningful involvement by the public.

7.21 References

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EPA, 1981. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, Document Number EPA-45012-81-078. Office of Air Quality Planning and Standards, Research Triangle Park, NC. December.

EPA, 1985. Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations), Document Number US EPA-450/4-80-023R. Office of Air Quality Planning and Standards, Research Triangle Park, NC.

EPA, 1992a. Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models. Dennis Atkinson and Russell F. Lee. July 7.

EPA, 1992b. Workbook for Plume Visual Impact Screening and Analysis. Document Number EPA-4541R-92-023. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October.

EPA, 2003. Guideline on Air Quality Models, (Revised) EPA450/12-78-027R, Office of Air Quality Planning and Standards. Research Triangle Park, NC.

EPA, 2009. AERMOD Implementation Guide. AERMOD Implementation Workgroup, Office of Air Quality Planning and Standards. Research Triangle Park, NC. Revised March 19, 2009.

ESS, 2009. Email communication between Dammon Frecker, ESS and Lisa Landry, Gary Milbury and David Healey, NHDES. September 22.

NHDES, 2006. Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire. New Hampshire Department of Environmental Services, Air Resources Division. July.

NHDES, 2009. Email communication between Lisa Landry, NHDES and Dammon Frecker, ESS. August 19.

NHDES, 2010a. Email communication between Lisa Landry, NHDES and Dammon Frecker, ESS.

NHDES, 2010b. Email communication between Lisa Landry, NHDES and John Purdum, ESS.

National Park Service, Website www.nature.nps.gov/air/Maps/Receptors/index.cfm

8.0 APPLICATION FORMS

This section contains completed versions of the following required NHDES air permit application forms:

- Signed Affidavit - Demonstration of Title, Right and Interest in Property
- Form ARD-1: General Information for all Permit Applications
- Form ARD-2: Information Required for Permits for Fuel Burning Devices
  - Biomass Boiler
  - Fire Pump
- Form ARD-3: Information Required for Permits for a Unit of Processing or Manufacturing Equipment
  - Cooling Tower
- Form ARD-4: Information Required for Permits for Storage Tanks Containing Fuel or Volatile Organic Compounds
  - ULSD Storage Tank

Tables

Figures

Appendix A

Potential Emissions Calculation Summaries

Appendix B

Visual Simulations of Proposed Facility

Appendix C

Equipment Specifications

ESS Group, Inc.

Engineers
Scientists
Consultants

888 Worcester Street
Suite 240
Wellesley
Massachusetts
02482
p 781.431.0500

May 19, 2010

Gary D. Millbury
Air Permit Program Manager
Permitting & Environmental Health Bureau
New Hampshire Department of Environmental Services
29 Hazen Drive
Concord, New Hampshire 03302-0095

Re: Revised Air Permit Application
Laidlaw Berlin BioPower LLC
Facility ID#3300790137; Application #09-0285

Dear Mr. Millbury:

On behalf of our client, Laidlaw Berlin BioPower (LBB), ESS Group Inc. (ESS), is providing the enclosed copies of the revised air permit application for the above referenced project. As we have previously discussed with your and your staff, the primary revisions to project as reflected in the revised application include:

- Reductions in the proposed emission rates for particulate matter, nitrogen oxides, and sulfur dioxide.
- Changes in the proposed emissions control train including incorporation of a dry sorbent injection system to further minimize sulfur dioxide emissions and use of fabric filter baghouse in place of the previously proposed electrostatic precipitator to control particulate emissions.
- Modifications to the stack parameters for the proposed emergency diesel engine powered fire pump and elimination of the previously proposed emergency generator.

The above changes further reduce the air emissions of the Project and further assure that it will not result in adverse impacts to the community of the environment.

Please contact me with any questions you may have regarding the enclosed materials.

Sincerely,

ESS GROUP, INC.

Dammon M. Frecker
Vice President, Energy & Industrial Services

Enclosures

C: Laidlaw Berlin BioPower

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division
P.O. Box 95
Concord, NH 03302-0095
Telephone: 603-271-1370

Form ARD-1

General Information for All Permit Applications

I. FACILITY INFORMATION - *Complete the following*:

A. Type of Application: ☒ New ☐ Renewal ☐ Modification

B. Physical Location:

Berlin BioPower
Facility Name

57 Hutchins Street
Street

Berlin — NH — 03570
Town/City — State — Zip Code

C. Mailing Address:

57 Hutchins Street
Street/P.O. Box

Berlin — NH — 03570
Town/City — State — Zip Code

Telephone Number

D. USGS Coordinates:

UTM	
Easting:	326984
Northing:	4926531

or

Latitude/Longitude			
N Latitude:	Deg	Min	Sec
W Longitude:	Deg	Min	Sec

E. Owner:

Laidlaw Berlin BioPower, LLC
Company

90 John Street - 4th Floor
Street/P.O. Box

New York — NY — 10038
Town/City: — State — Zip Code

212-480-9884
Telephone Number

F. Parent Corporation:

Laidlaw Berlin BioPower, LLC
Company

Michael Bartoszek / CEO
Contact Person/Title

90 John Street - 4th Floor
Street/P.O. Box

New York — NY — 10038
Town/City: — State — Zip Code

212-480-9884
Telephone Number

G. Contact Information

1. General/Technical Contact:

Louis T. Bravakis
Contact Person

Vice President
Title

45 State Street
Address

Montpelier — VT — 05602
Town/City — State — Zip Code

802-229-4146
Telephone Number

LTB@laidlawenergy.com
E-mail Address

2. Application Preparation:

ESS Group, Inc.
Company

Dammon Frecker
Contact Person

888 Worcester Road - Suite 240
Address

Wellesley — MA — 02482
Town/City — State — Zip Code

781-489-1146
Telephone Number

dfrecker@esssgroup.com
E-mail Address

Form ARD-1

3. Legal Contact:

Barry Needleman
Contact Person

Project Counsel
Title

11 South Main Street - Suite 500
Address

Concord NH 03301
Town/City State Zip Code

603-230-4407
Telephone Number

Barry.Needleman@McLane.com
E-mail Address

4. Invoicing Contact:

Michael Bartoszek
Contact Person

President & CEO
Title

90 John Street - 4th Floor
Address

New York NY 10038
Town/City State Zip Code

212-480-9884
Telephone Number

mbb@laidlawenergy.com
E-mail Address

H. Major Activity or Product Descriptions - *List all activities performed at this facility and provide SIC code(s):*

Description of Activity or Product	SIC Code
Production and distribution of electricity	4911

I. Other Sources or Devices - *List sources or devices at the facility (other than those that are the subject of this application) that are permitted pursuant to Env-A 600:*

Source or Device	Permit #	Expiration Date
None		

II. Total Facility Emissions Data:

Pollutant	CAS #	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)
NOx	10102-43-9	66.9	66.9	244.7	244.7
CO	630-08-0	83.6	83.6	307.5	307.5
SO2	89125-89-3	13.4	13.4	48.6	48.6
PM	N/A	11.1	11.1	43.3	43.3
VOC	N/A	11.1	11.1	40.6	40.6
Also see Attached Table 3.2					

Note: For Regulated Toxic Air Pollutants list name and Chemical Abstract Service Number (CAS #) – *use additional sheets if necessary.*

Form ARD-1

III. **Support Data** *The following data must be submitted with this application:*

☒ A copy of all calculations used in determining emissions;
☒ A copy of a USGS map section with the site location clearly indicated; and
☒ A to-scale site plan of the facility showing:

1. the locations of all emission points;
2. the dimensions of all buildings, including roof heights; and
3. the facility's property boundary.

IV. **Certification (To be completed by a responsible official only):**

I am authorized to make this submission on behalf of the affected source or affected units for which this submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the information submitted in this document and all of its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Print/Type Name: Louis T. Bravakis Title: Vice President

Signed: [signature] Date: 05-18-10

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Form ARD-2

Information Required for Permits for Fuel Burning Devices

I. EQUIPMENT INFORMATION – *Complete a separate form for each device.*

Device Description: Wood-Fired Boiler
Date Construction Commenced: ____________ **Device Start-Up Date:** ____________

A. Boiler ☐ Not Applicable

B&W Boiler Manufacturer	N/A Boiler Model Number
N/A Boiler Serial Number	1,013 Gross Heat Input Nameplate Rating (MMBtu/hr)
N/A Burner Manufacturer	N/A Burner Model Number
N/A Burner Serial Number	124.9 ☐ gal/hr ☐ mmcf/hr ☒ ton/hr Potential Fuel Flow Rate

1. Type of Burner:

a. Solid Fuel:
- ☐ Cyclone
- ☐ Pulverized (☐ wet ☐ dry)
- ☐ Spreader Stoker
- ☐ Underfeed Stoker
- ☐ Overfeed Stoker
- ☐ Hand-Fired
- ☐ Fly Ash Re-injection
- ☒ Other (specify): Bubbling Fluidized bed

b. Liquid Fuel:
- ☐ Pressure Gun
- ☐ Rotary Cup
- ☐ Steam Atomization
- ☒ Air Atomization
- ☐ Other (specify): ____________

c. Gaseous Fuel:
- ☐ Natural Gas
- ☐ Propane
- ☐ Other (specify): ____________

2. Combustion Type:
- ☐ Tangential Firing
- ☐ Opposite End Firing
- ☐ Limited Excess Firing
- ☒ Flue Gas Recirculation
- ☐ Staged Combustion
- ☐ Biased Firing
- ☐ One End Only Firing
- ☐ Other (specify): ____________

B. Internal Combustion Engines/Combustion Turbines ☒ Not Applicable

Manufacturer	Model Number
Serial Number	☐ gal/hr ☐ mmcf/hr Fuel Flow Rate
☐ hp ☐ kW Engine Output Rating	Reason for Engine Use

Form ARD-2

C. Stack Information

Is unit equipped with multiple stacks? ☐ Yes ☒ No *(if yes, provide data for each stack)*

Identify other devices on this stack: ____________________

Is Section 123 of the Clean Air Act applicable? ☐ Yes ☒ No

Is stack monitoring used? ☒ Yes ☐ No

If yes, Describe: Opacity COMS, NOx & CO CEMS

Is stack capped or otherwise restricted? ☐ Yes ☒ No

If yes, Describe: ____________________

Stack exit orientation: ☒ Vertical ☐ Horizontal ☐ Downward

11.25
Stack ☒ Inside Diameter (ft) ☐ Exit Area (ft^2)

320
Discharge height above ground level (ft)

382,000
Exhaust Flow (acfm)

64
Exhaust Velocity (ft/sec)

369
Exhaust Temperature (°F)

II. OPERATIONAL INFORMATION

A. Fuel Usage Information

1. Fuel Supplier:

Varies
Supplier's Name

Street

Town/City State Zip Code

Telephone Number

2. Fuel Additives:

None
Manufacturer's Name

Street

Town/City State Zip Code

Telephone Number

Identification of Additive

Consumption Rate (gallons per 1000 gallons of fuel)

3. Fuel Information *(List each fuel utilized by this device)*:

Type	% Sulfur	% Ash	% Moisture (solid fuels only)	Heat Rating (specify units)	Potential Heat Input (MMBtu/hr)	Actual Annual Usage (specify units)
Woodwaste	0.04	<1	37.6-50	5060 Btu/lb	1013	750,000 tons
No 2 Oil	0.0015	0.01	N/A	139,000 Btu/gal	240	82,272 gal.

B. Hours of Operation

Hours per day: 24 Days per year: 365

Form ARD-2

III. POLLUTION CONTROL EQUIPMENT ☐ Not Applicable

A. Type of Equipment *Note: if process utilizes more than one control device, provide data for each device*

- ☐ baffled settling chamber
- ☐ long cone cyclone
- ☐ multiple cyclone (______ inch diameter)
- ☐ electrostatic precipitator
- ☐ spray tower
- ☐ venturi scrubber
- ☐ afterburners (incineration)
- ☒ selective catalytic reduction
- ☐ reburn
- ☒ other (specify): Dry sorbent injection
- ☐ wide bodied cyclone
- ☐ irrigated long cone cyclone
- ☐ carbon absorption
- ☐ irrigated electrostatic precipitator
- ☐ absorption tower
- ☒ baghouse
- ☐ packed tower/column
- ☐ selective non-catalytic reduction

B. Pollutant Input Information

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)
NOx	438	224	243	981	1064
PM	438	2237	2431	9798	10648
CO	438	69.9	83.6	306	366
SO2	438	23.3	27.9	102	122
VOC	438	9.3	11.1	41	49

Method used to determine entering emissions:

☐ stack test ☒ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ____________________

C. Operating Data

1. Capture Efficiency: 100% Verified by: ☐ test ☒ calculations
2. Control Efficiency: 70 NOx/99.5 PM% Verified by: ☐ test ☒ calculations
3. Normal Operating Conditions *(supply the following data as applicable)*

498000	438	nd
Total gas volume through unit (acfm)	Temperature (°F)	Percent Carbon Dioxide (CO_2)
nd	nd	nd
Voltage	Spark Rate	Milliamps
nd	nd	
Pressure Drop (inches of water)	Liquid Recycle Rate (gallons per minute)	

Form ARD-2

IV. DEVICE EMISSIONS DATA:

Pollutant	Temperature (°F)	Actual (lb/hr)[1]	Potential (lb/hr)[2]	Actual (ton/yr)[3]	Potential (ton/yr)
NOx	369	55.9	66.9	208	245
PM	369	9.3	11.1	34.8	40.9
CO	369	69.9	83.6	261	307
SO2	369	11.2	13.4	41.4	48.7
VOC	369	9.3	11.1	34.5	40.6

Method used to determine exiting emissions:

☐ stack test ☒ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ______________________________

1 – Actual lb/hr emission rates based on annual average heat input rate

2 – Potential lb/hr emission rates based on maximum heat input rate plus 10%

3 – Actual ton/yr emission rates assume 85% annual capacity factor

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Form ARD-2

Information Required for Permits for Fuel Burning Devices

I. EQUIPMENT INFORMATION – *Complete a separate form for each device.*

Device Description: Diesel Fire Pump

Date Construction Commenced: ______________ **Device Start-Up Date:** ______________

A. Boiler ☒ Not Applicable

Boiler Manufacturer:	Boiler Model Number:
Boiler Serial Number:	Gross Heat Input Nameplate Rating (MMBtu/hr):
Burner Manufacturer:	Burner Model Number:
Burner Serial Number:	Potential Fuel Flow Rate: ☐ gal/hr ☐ mmcf/hr ☐ ton/hr

1. Type of Burner:

a. Solid Fuel:
- ☐ Cyclone
- ☐ Pulverized (☐ wet ☐ dry)
- ☐ Spreader Stoker
- ☐ Underfeed Stoker
- ☐ Overfeed Stoker
- ☐ Hand-Fired
- ☐ Fly Ash Re-injection
- ☐ Other (specify): ______________

b. Liquid Fuel:
- ☐ Pressure Gun
- ☐ Rotary Cup
- ☐ Steam Atomization
- ☐ Air Atomization
- ☐ Other (specify): ______________

c. Gaseous Fuel:
- ☐ Natural Gas
- ☐ Propane
- ☐ Other (specify): ______________

2. Combustion Type:
- ☐ Tangential Firing
- ☐ Opposite End Firing
- ☐ Limited Excess Firing
- ☐ Flue Gas Recirculation
- ☐ Staged Combustion
- ☐ Biased Firing
- ☐ One End Only Firing
- ☐ Other (specify): ______________

B. Internal Combustion Engines/Combustion Turbines ☐ Not Applicable

Manufacturer: Cummings	Model Number: CFP9E-F30 or equivalent
Serial Number: TBD	Fuel Flow Rate: 16.2 ☒ gal/hr ☐ mmcf/hr
Engine Output Rating: 323 (max) ☒ hp ☐ kW	Reason for Engine Use: Emergency Fire water pump

Form ARD-2

C. Stack Information

Is unit equipped with multiple stacks? ☐ Yes ☒ No *(if yes, provide data for each stack)*

Identify other devices on this stack: ____________________

Is Section 123 of the Clean Air Act applicable? ☐ Yes ☒ No

Is stack monitoring used? ☐ Yes ☒ No

If yes, Describe: ____________________

Is stack capped or otherwise restricted? ☐ Yes ☒ No

If yes, Describe: ____________________

Stack exit orientation: ☒ Vertical ☐ Horizontal ☐ Downward

0.5
Stack ☒ Inside Diameter (ft) ☐ Exit Area (ft^2)

25
Discharge height above ground level (ft)

1,973
Exhaust Flow (acfm)

167
Exhaust Velocity (ft/sec)

1058
Exhaust Temperature (°F)

II. OPERATIONAL INFORMATION

A. Fuel Usage Information

1. Fuel Supplier:

TBD
Supplier's Name

Street

Town/City State Zip Code

Telephone Number

2. Fuel Additives:

NA
Manufacturer's Name

Street

Town/City State Zip Code

Telephone Number

Identification of Additive

Consumption Rate (gallons per 1000 gallons of fuel)

3. Fuel Information *(List each fuel utilized by this device)*:

Type	% Sulfur	% Ash	% Moisture (solid fuels only)	Heat Rating (specify units)	Potential Heat Input (MMBtu/hr)	Actual Annual Usage (specify units)
ULSD	0.0015	0.01	NA	140,000 Btu/gal	2.27	8,100 gals

B. Hours of Operation

Hours per day: 1 Days per year: 300 hr/yr

Form ARD-2

III. POLLUTION CONTROL EQUIPMENT ☒ Not Applicable

A. Type of Equipment *Note: if process utilizes more than one control device, provide data for each device*

- ☐ baffled settling chamber
- ☐ long cone cyclone
- ☐ multiple cyclone (______ inch diameter)
- ☐ electrostatic precipitator
- ☐ spray tower
- ☐ venturi scrubber
- ☐ afterburners (incineration)
- ☐ selective catalytic reduction
- ☐ reburn
- ☐ other (specify): ____________________
- ☐ wide bodied cyclone
- ☐ irrigated long cone cyclone
- ☐ carbon absorption
- ☐ irrigated electrostatic precipitator
- ☐ absorption tower
- ☐ baghouse
- ☐ packed tower/column
- ☐ selective non-catalytic reduction

B. Pollutant Input Information

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)

Method used to determine entering emissions:

☐ stack test ☐ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ______________________________

C. Operating Data

1. Capture Efficiency: ______% Verified by: ☐ test ☐ calculations
2. Control Efficiency: ______% Verified by: ☐ test ☐ calculations
3. Normal Operating Conditions *(supply the following data as applicable)*

Total gas volume through unit (acfm)	Temperature (°F)	Percent Carbon Dioxide (CO_2)
Voltage	Spark Rate	Milliamps
Pressure Drop (inches of water)	Liquid Recycle Rate (gallons per minute)	

Form ARD-2

IV. DEVICE EMISSIONS DATA:

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)[1]	Potential (ton/yr)[2]
NOx	952	1.57	1.57	.078	0.39
CO	952	1.01	1.01	0.05	0.25
SO2	952	0.0031	0.0031	0.00016	0.0008
PM	952	0.084	0.084	0.0042	0.021
VOC	952	0.088	0.088	0.0044	0.022

Method used to determine exiting emissions:

☐ stack test ☒ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ______________________

1 – Actual ton/yr emissions assume 100 actual operating hours per year.

2 – Potential ton/yr emissions based on 500 allowable operating hours per year.

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Form ARD-3

Information Required for Permits for a Unit of Processing or Manufacturing Equipment

I. EQUIPMENT INFORMATION – *Complete a separate form for each device.*

Device Description: Cooling Tower - 4 cell

Date Construction Commenced: TBD **Device Start-Up Date:** TBD

Equipment Manufacturer: SPX Cooling Technologies

Model Number: F499-4.0-4 **Serial Number:** TBD

A. Raw Materials Entering Process

Description	Actual Usage (lb/hr)	Maximum Usage (lb/hr)	Actual Usage (tons/yr)
Cooling Water	496,860	496,860	2.18 million

B. Coatings and Solvents Entering Process

Description	Weight % of Solvent	Reason for Use	Actual Usage (lb/hr)	Maximum Usage (lb/hr)	Actual Usage (tons/yr)
NA					

C. Amount of Liquid Waste Discarded: NA

☐ gal/yr
☐ tons/yr

Form ARD-3

D. Stack Information

Is unit equipped with multiple stacks? ☒ Yes ☐ No *(if yes, provide data for each stack)*

Identify other devices on this stack: 4 cells, 4 exhausts

Is Section 123 of the Clean Air Act applicable? ☐ Yes ☒ No

Is stack monitoring used? ☐ Yes ☒ No

If yes, Describe: ______

Is stack capped or otherwise restricted? ☐ Yes ☒ No

If yes, Describe: ______

Stack exit orientation: ☒ Vertical ☐ Horizontal ☐ Downward

31.6 each
Stack ☒ Inside Diameter (ft) ☐ Exit Area (ft^2)

48
Discharge height above ground level (ft)

1,300,000
Exhaust Flow (acfm)

27.6
Exhaust Velocity (ft/sec)

96
Exhaust Temperature (°F)

II. OPERATIONAL INFORMATION

A. Supplemental Fuel Usage Information

1. Fuel Supplier:

NA
Supplier's Name

Street

Town/City State Zip Code

Telephone Number

2. Fuel Additives:

NA
Manufacturer's Name

Street

Town/City State Zip Code

Telephone Number

Identification of Additive

Consumption Rate (gallons per 1000 gallons of fuel)

3. Fuel Information *(List each fuel utilized by this device)*:

Type	% Sulfur	% Ash	% Moisture (solid fuels only)	Heat Rating (specify units)	Potential Heat Input (MMBtu/hr)	Actual Annual Usage (specify units)

B. Hours of Operation

Hours per day: 24 Days per year: 365

Form ARD-3

III. POLLUTION CONTROL EQUIPMENT ☐ Not Applicable

A. Type of Equipment *Note: if process utilizes more than one control device, provide data for each device*

- ☐ baffled settling chamber
- ☐ long cone cyclone
- ☐ multiple cyclone (______ inch diameter)
- ☐ electrostatic precipitator
- ☐ spray tower
- ☐ venturi scrubber
- ☐ afterburners (incineration)
- ☐ selective catalytic reduction
- ☐ reburn
- ☒ other (specify): drift eliminators
- ☐ wide bodied cyclone
- ☐ irrigated long cone cyclone
- ☐ carbon absorption
- ☐ irrigated electrostatic precipitator
- ☐ absorption tower
- ☐ baghouse
- ☐ packed tower/column
- ☐ selective non-catalytic reduction

B. Pollutant Input Information

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)
PM	96	600	600	2628	2628

Method used to determine entering emissions:

☐ stack test ☒ vendor data ☐ emission factor ☐ material balance

☐ other
(specify): ____________________

C. Operating Data

1. Capture Efficiency: ______% Verified by: ☐ test ☐ calculations
2. Control Efficiency: 99.95% Verified by: ☐ test ☒ calculations
3. Normal Operating Conditions *(supply the following data as applicable)*

Total gas volume through unit (acfm)	1,300,000
Temperature (°F)	96
Percent Carbon Dioxide (CO_2)	0
Voltage	NA
Spark Rate	NA
Milliamps	NA
Pressure Drop (inches of water)	NA
Liquid Recycle Rate (gallons per minute)	NA

Form ARD-3

IV. DEVICE EMISSIONS DATA:

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)
PM	96	0.30	0.30	1.3	1.3

Method used to determine exiting emissions:

☐ stack test ☒ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ____________________

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Form ARD-4

Information Required for Permits for Storage Tanks Containing Fuel or Volatile Organic Compounds

I. EQUIPMENT INFORMATION – *Complete a separate form for each tank.*

Tank Description: 50,000 gallon nominal capacity API-650 steel fuel tank

Date Construction Commenced: ____________ **Initial Fill Date:** ____________

Location: ☐ Underground ☒ Aboveground

A. Tank Type

1. Fixed Roof Tanks:

☒ Floating Roof Covered Type

☐ Floating Roof Open Type:

- ☐ Pan
- ☐ Pontoon
- ☐ Double Deck

2. Variable Vapor Space Tanks:

☐ Lifter Roof

☐ Flexable Diaphram

Seal Type:

☐ Single

☐ Double

☐ Welded

Connected to Other Tanks? ☐ Yes ☐ No

Specify Other Tanks: ____________

3. Pressure Tanks:

☐ Spheroid

☐ Horizontal Cylinder

☐ Vertical Cylinder

Internal Pressure: ______ @ ______ °F

4. Other Tank Type (specify): ____________

B. Tank Information

Height (feet): 16

Inside Diameter (feet): 23

Roof Slope (inches/ft): API-650 self supporting conical roof

Roof Color: white

Side Color: white

Tank Fill Capacity (gallons): 50,000

Annual Throughput (gallons/year): 100,000

	Yes	No	If Yes:	
Insulated?	☐	☒	Material Type:	____________
Heated?	☐	☒	Temperature (°F):	____________
Lined?	☐	☒	Liner Type:	____________

For variable vapor space systems:

Actual Annual Number of Shipments into Tank: ____________

Actual volume per shipment (gallons): ____________

Potential volume expansion capability of variable vapor space (gallons): ________

Pressure Setting (lb/in^2): ____________ Vacuum Setting (lb/in^2): ____________

Form ARD-4

C. Liquid Information

ULSD
Liquid Type

180
Molecular Weight

70
Average Bulk Liquid Temperature (°F)

0.009
True vapor pressure at average bulk liquid temperature (psia)

6.92
Average density at bulk liquid conditions (lbs/gal)

D. Stack Information

Is unit equipped with multiple stacks? ☐ Yes ☒ No *(if yes, provide data for each stack)*

Identify other devices on this stack: ____________________

Is Section 123 of the Clean Air Act applicable? ☐ Yes ☐ No

Is stack monitoring used? ☐ Yes ☒ No

If yes, Describe: ____________________

Is stack capped or otherwise restricted? ☐ Yes ☒ No

If yes, Describe: ____________________

Stack exit orientation: ☐ Vertical ☐ Horizontal ☒ Downward

Tank will have an Atmospheric vent
Stack ☐ Inside Diameter (ft) ☐ Exit Area (ft^2)

16
Discharge height above ground level (ft)

N/A
Exhaust Flow (acfm)

N/A
Exhaust Velocity (ft/sec)

ambient
Exhaust Temperature (°F)

E. Hours of Operation

Hours per day: 24 Days per year: 365

II. POLLUTION CONTROL EQUIPMENT ☒ Not Applicable

A. Type of Equipment *Note: if process utilizes more than one control device, provide data for each device*

- ☐ baffled settling chamber
- ☐ long cone cyclone
- ☐ multiple cyclone (_____ inch diameter)
- ☐ electrostatic precipitator
- ☐ spray tower
- ☐ venturi scrubber
- ☐ afterburners (incineration)
- ☐ selective catalytic reduction
- ☐ reburn
- ☐ other (specify): ____________________
- ☐ wide bodied cyclone
- ☐ irrigated long cone cyclone
- ☐ carbon absorption
- ☐ irrigated electrostatic precipitator
- ☐ absorption tower
- ☐ baghouse
- ☐ packed tower/column
- ☐ selective non-catalytic reduction

Device: ______________________

Form ARD-4

B. Pollutant Input Information

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)

Method used to determine entering emissions:

☐ stack test ☐ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ______________________________

C. Operating Data

1. Capture Efficiency: ______% Verified by: ☐ test ☐ calculations
2. Control Efficiency: ______% Verified by: ☐ test ☐ calculations
3. Normal Operating Conditions *(supply the following data as applicable)*

______________________ Total gas volume through unit (acfm)

______________________ Temperature (°F)

______________________ Percent Carbon Dioxide (CO_2)

______________________ Voltage

______________________ Spark Rate

______________________ Milliamps

______________________ Pressure Drop (inches of water)

______________________ Liquid Recycle Rate (gallons per minute)

III. DEVICE EMISSIONS DATA:

Pollutant	Temperature (°F)	Actual (lb/hr)	Potential (lb/hr)	Actual (ton/yr)	Potential (ton/yr)

Method used to determine exiting emissions:

☐ stack test ☐ vendor data ☐ emission factor ☐ material balance

☐ other (specify): ______________________________

Table 3.2
Facility Potential Emissions Summary
Berlin BioPower - Berlin, New Hampshire

Pollutant	Potential Total Emissions (tons per year)						
	Biomass Boiler	Fire Pump	Cooling Tower	PTE - Normal Operation[(1)]	Boiler Startup[(2)]	Fugitive Emissions[(3)]	Facility PTE[(4)]
Maximum Hours of Operation per Year	8,688	300	8,760	8,688	72	8,760	
NO_x	242.9	0.2	0.0	243.2	1.6	0.0	244.7
CO	303.6	0.2	0.0	303.8	3.7	0.0	307.5
SO_2	48.6	0.0	0.0	48.6	0.1	0.0	48.6
H_2SO_4	7.4	0.0	0.0	7.4	0.0	0.0	7.4
PM (filterable)	40.5	0.0	1.3	41.8	0.4	1.1	43.3
PM_{10} (filterable)	40.5	0.0	1.3	41.8	0.4	0.5	42.7
$PM_{2.5}$ (filterable)	40.5	0.0	1.3	41.8	0.4	0.1	42.3
CO_2	894,864	51	0	894,915	1,924	0	896,839
NH_3	49.5	0.0	0.0	49.5	0.0	0.0	49.5
VOC	40.5	0.0	0.0	40.5	0.1	0.0	40.6
Formaldehyde	17.8	0.0	0.0	17.8	0.0	0.0	17.8
Hydrogen Chloride	3.4	0.0	0.0	3.4	0.0	0.0	3.4
Lead	0.2	0.0	0.0	0.2	0.0	0.0	0.2
Mercury	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total HAPS	65.0	0.0	0.0	65.0	0.1	0.0	65.1

(1) Total emissions represent maximum potential of all equipment operating independently in normal operation. The biomass boiler emissions are based on 932 MMBtu/hr average heat input. As all equipment will not run for maximum potential hours shown, actual emissions will be less.
(2) Boiler startup emissions have been estimated assuming a total of 6 cold startups per year. Emissions during shutdown periods are aggregated with emissions during normal boiler operation.
(3) Fugitive emissions resulting from wood fuel storage and handling activities.
(4) The Facility PTE is the sum of the PTE of all sources during normal operation, emissions during startup and shutdown of the Biomass Boiler, and fugitive emissions.

Table 7.1
Biomass Boiler, Emergency Generator & Fire Pump Stack and Exhaust Parameters Summary
Berlin BioPower - Berlin, New Hampshire

	Biomass Boiler									Fire Pump
Load (%)	Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	Load (%)	Max (100%)
Ambient Temp (F)	60	60	60	60	60	60	60	60		
Fuel Moisture (%)	37.6	37.6	50	50	37.6	37.6	50	50		
Stack Temperature (F)	369	260	366	260	375	260	370	260		
Heat Input Rate (MMBtu/hr)	932	932	1,013	1,013	654	654	711	711	Power Output (hp)	323
Exhaust Flow (acfm)	382,000	331,773	448,000	390,508	270,000	232,814	315,891	274,026	Exhaust Flow (acfm)	1,973
Exit Velocity (ft/sec)	64.05	55.63	75.12	65.48	45.27	39.04	52.97	45.95	Exit Velocity (ft/sec)	167.47
Exit Velocity (m/sec)	19.52	16.96	22.90	19.96	13.80	11.90	16.14	14.00	Exit Velocity (m/sec)	51.05
Temp (F)	369	260	366	260	375	260	370	260	Temp (F)	1058
Temp (K)	460	400	459	400	464	400	461	400	Temp (K)	843
Emissions (lb/MMBtu)									Emissions (g/hp-hr)	
NOx	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	NOx	2.2
CO	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	CO	1.417
SO2	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	SO2	
PM10	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	PM10	0.118
PM2.5	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	PM2.5	0.118
Emissions (lb/hr) *									Emissions (lb/hr)	
NOx	61.51	61.51	66.86	66.86	43.16	43.16	46.92	46.92	NOx	1.57
CO	76.89	76.89	83.57	83.57	53.96	53.96	58.64	58.64	CO	1.01
SO2	12.30	12.30	13.37	13.37	8.63	8.63	9.38	9.38	SO2	0.0031
PM10	10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	PM10	0.084
PM2.5	10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	PM2.5	0.084

Stack Height	320	feet/meters	97.5	Stack Height	25
Stack Diameter	11.25	feet/meters	3.43	Stack Diameter	0.5
Stack Area	99.40	sq ft		Stack Area	0.20
Base Elevation	1041	ft/m msl	317.3	Base Elevation	1041
Stack Coordinates	718944.4049	State Plane ft N		Stack Coordinates	
	1112520.156	State Plane ft S			

* Short term boiler emission rates have been increased by 10% to account for variability in stack flow rates. Annual boiler impacts have been determined without the use of the 10% factor.

Table 7.1a
Biomass Boiler Stack and Exhaust Parameters Summary - Cold Startup
Berlin BioPower - Berlin, New Hampshire

	Biomass Boiler - Startup				
Startup Phase	Phase 1	Phase 2			Phase 3
Startup Phase Duration	8 hours	3 hours			1 hour
Boiler Fuel	ULSD	ULSD	Wood	Combined	Wood
Heat Input Rate (MMBtu/hr)	240	120	233	353	559
Exhaust Flow (acfm)	191,764	46,292	89,981	228,107	345,627
Exit Velocity (ft/sec)	32.15	7.76	15.09	38.25	57.95
Exit Velocity (m/sec)	9.80	2.37	4.60	11.66	17.66
Temp (F)	300	300	300	300	300
Temp (K)	422	422	422	422	422
Emissions (lb/MMBtu)					
NOx	0.20	0.20	0.06		0.06
CO	0.50	0.50	0.075		0.075
SO2	0.002	0.002	0.012		0.012
PM10	0.05	0.05	0.01		0.01
PM2.5	0.05	0.05	0.01		0.01
Emissions (lb/hr)					
NOx	48.00	24.00	13.98	37.98	33.55
CO	120.00	60.00	17.48	77.48	41.94
SO2	0.48	0.24	2.80	3.04	6.71
PM10	12.00	6.00	2.33	8.33	5.59
PM2.5	12.00	6.00	2.33	8.33	5.59

Stack Height	320	feet/meters	97.5
Stack Diameter	11.25	feet/meters	3.43
Stack Area	99.40	sq ft	
Base Elevation	1041	ft/m msl	317.3
Stack Coordinates	718944.4049	State Plane ft N	
	1112520.156	State Plane ft S	

Table 7.2
Cooling Tower Emissions Summary
Berlin BioPower - Berlin, New Hampshire

Cooling Tower Specification	Data Source	Data Result
Hours of Operation:		8,760 hours
Circulating Water Flow Rate:	SPX	60,000 gpm
Drift Eliminator Efficiency:	SPX	0.0005 %
Total Liquid Drift:	calc.	0.30 gpm
Density of Water:	constant	8.34 lb/gal
Total Liquid Drift:	calc.	150.1 lb/hr
Circulating Water TDS:	calc.	2,000 ppm
PM_{10} Emission Rate:	calc.	0.30 lb/hr
PM_{10} Emission Rate:	calc.	1.32 ton/yr

Calculations
Total Liquid Drift (gpm) = (Circulating Water Flow Rate, gpm) x (Drift Eliminator Efficiency, %)
Total Liquid Drift (lb/hr) = (Total Liquid Drift, gpm) x (Density of Water, lb/gal)
PM_{10} Emission Rate (lb/hr) = (Total Liquid Drift, lb/hr) x ((Circulating Water TDS, ppm) / 10^6)
PM_{10} Emission Rate (ton/yr) = (PM_{10} Emission Rate, lb/hr) x (Hours of Operation) x (1 ton / 2000 lbs)

Table 7.3
GEP Stack Height Analysis
Berlin BioPower – Berlin, New Hampshire

Building Tiers	Height (ft)	Projected Width (ft)	Formula GEP Height (ft)	Stacks > GEP Height	Building Distance from Stack (ft)			'5L' Distance (ft)	Stacks within 5L?
					Boiler	Cooling Tower	Fire Pump		
Boiler House	164.5	144.8	381.8	None	40	162	280	724	All
SCR Area	132.5	111.7	300.1	Boiler	100	160	320	558	All
ESP	113.2	150.7	283.0	Boiler	96	60	200	566	All

Table 7.4
Cavity Analysis
Berlin BioPower – Berlin, New Hampshire

Building Tiers	Height (ft)	Projected Width (ft)	Cavity Height (1.5L) (ft)	Stacks > Cavity Height	Cavity Region Distance (ft)	Stacks Within Cavity Region	Distance From Property Line (ft)	Cavity Extends Offsite?
Boiler House	164.5	144.8	236.9	Boiler	434	All	200	Yes
SCR Area	132.5	111.7	188.4	Boiler	335	All	170	Yes
ESP	113.2	150.7	169.8	Boiler	340	All	200	Yes

Table 7.5
Stability Class/Wind Speed Combinations Used for the Screening Modeling
Berlin BioPower – Berlin, New Hampshire

Stability Class	Wind Speed (m/sec)
A	1, 1.5, 2, 2.5, 3
B	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5
C	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5, 8, 10
D	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5, 8, 10, 15, 20
E	1, 1.5, 2, 2.5, 3, 3.5, 4, 4.5, 5
F	1, 1.5, 2, 2.5, 3, 3.5, 4

Table 7.6
Wind Speed/Mixing Height Combinations Used for the Screening Modeling
Berlin BioPower – Berlin, New Hampshire

Wind Speed (m/sec)	Mixing Height (m)
1	320
1.5	480
2	640
2.5	800
3	960
3.5	1,120
4	1,280
4.5	1,440
5	1,600
8	2,560
10	3,200
15	4,800
20	6,400

Table 7.7
Simple Terrain Screening Receptor Distances and Elevations
Berlin BioPower – Berlin, New Hampshire

Distance (km)	Elevation (meters mean sea level)	Elevation (meters above stack base)
0-0.150	317.3	0
0.200	326.5	9
0.250	333.6	16
0.300	340.8	23
0.350	350.5	33
0.400	360.8	44
0.450	370.8	53
0.500	377.2	60
0.600	387.2	70
0.700	396.0	79
0.800	420.8	86
0.900-50	419.2	98

Table 7.8
Complex Terrain Screening Receptor Distances and Elevations
Berlin BioPower – Berlin, New Hampshire

Elevation (meters mean sea level)	Elevation (meters above stack base)	Distance (km)
419.2	102	0.9
436.9	120	1.0
455.4	138	1.1
475.8	159	1.2
499.8	183	1.3
510.8	194	1.4
514.3	197	1.5
570.3	253	1.7
575.1	258	1.8
617.2	300	1.9
618.9	302	2.0
653.1	336	3.4
710.2	393	3.6
731.7	414	4.0
736.3	419	4.5
762.6	445	5.0
861.3	544	6.0
888.7	571	6.5
925.3	608	8.5
1108.8	692	11.0
1051.6	734	15.0
1321.3	1004	17.0
1463.0	1147	18.0
1643.4	1326	19.0

Table 7.9
SCREEN3 Class II Modeling Results
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Cooling Tower	Fire Pump
Load (%)		Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	100	100
Ambient Temp (F)		60	60	60	60	60	60	60	60		
Fuel Moisture (%)		37.6	37.6	50	50	37.6	37.6	50	50		
Stack Temperature (F)		369	260	366	260	375	260	370	260		
Maximum Emission Rates (lb/hr)											
NOx		61.51	61.51	66.86	66.86	43.16	43.16	46.92	46.92	0.00	1.57
CO		76.89	76.89	83.57	83.57	53.96	53.96	58.64	58.64	0.00	1.01
SO2		12.30	12.30	13.37	13.37	8.63	8.63	9.38	9.38	0.00	0.0031
PM10		10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	0.30	0.084
PM2.5		10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	0.30	0.084
Maximum Emission Rates (g/sec)											
NOx		7.75	7.75	8.42	8.42	5.44	5.44	5.91	5.91	0.00	0.197
CO		9.69	9.69	10.53	10.53	6.80	6.80	7.39	7.39	0.00	0.127
SO2		1.55	1.55	1.68	1.68	1.09	1.09	1.18	1.18	0.00	0.00039
PM10		1.29	1.29	1.40	1.40	0.91	0.91	0.99	0.99	0.038	0.0106
PM2.5		1.29	1.29	1.40	1.40	0.91	0.91	0.99	0.99	0.038	0.0106
Simple Terrain Screening - Unit Emission Rate Impacts											
Emissions (g/sec)		1	1	1	1	1	1	1	1	1	1
1-hr Conc (ug/m3)		3.75	8.074	3.51	3.99	8.759	11.19	7.538	9.544	234.2	723.8
Simple Terrain Screening - Maximum Emission Rate Impacts											
NOx	1-hr	29.05	62.58	29.59	33.58	47.64	60.86	44.56	56.42	0.00	142.87
	Annual	2.11	4.55	2.15	2.44	3.46	4.43	3.24	4.10	0.00	11.43
CO	1-hr	36.31	78.22	36.99	41.97	59.55	76.07	55.70	70.52	0.00	92.02
	8-hr	25.42	54.76	25.89	29.38	41.68	53.25	38.99	49.37	0.00	64.41
SO2	1-hr	5.81	12.52	5.92	6.72	9.53	12.17	8.91	11.28	0.00	0.28
	3-hr	5.23	11.26	5.33	6.04	8.57	10.95	8.02	10.16	0.00	0.25
	24-hr	2.32	5.01	2.37	2.69	3.81	4.87	3.56	4.51	0.00	0.11
	Annual	0.42	0.91	0.43	0.49	0.69	0.89	0.65	0.82	0.00	0.023
PM10	1-hr	4.84	10.43	4.93	5.60	7.94	10.14	7.43	9.40	8.86	7.66
	24-hr	1.94	4.17	1.97	2.24	3.18	4.06	2.97	3.76	3.54	3.07
	Annual	0.35	0.76	0.36	0.41	0.58	0.74	0.54	0.68	0.71	0.61
PM2.5	1-hr	4.84	10.43	4.93	5.60	7.94	10.14	7.43	9.40	8.86	7.66
	24-hr	1.94	4.17	1.97	2.24	3.18	4.06	2.97	3.76	3.54	3.07
	Annual	0.35	0.76	0.36	0.41	0.58	0.74	0.54	0.68	0.71	0.61
Complex Terrain Screening - Unit Emission Rate Impacts											
Emissions (g/sec)		1	1	1	1	1	1	1	1	1	1
1-hr Conc (ug/m3)		15.80	19.10	14.39	18.07	18.57	20.54	17.01	19.88	30.94	49.16
24-hr Conc (ug/m3)		3.95	4.78	3.60	4.52	4.64	5.14	4.25	4.97	7.74	12.29
Complex Terrain Screening - Maximum Emission Rate Impacts											
NOx	1-hr	122.49	148.03	121.21	152.21	100.99	111.73	100.56	117.54	0.00	9.70
	Annual	8.91	10.77	8.81	11.07	7.34	8.13	7.31	8.55	0.00	0.78
CO	1-hr	153.11	185.04	151.51	190.26	126.23	139.66	125.70	146.93	0.00	6.25
	8-hr	107.18	129.53	106.06	133.18	88.36	97.77	87.99	102.85	0.00	4.38
SO2	1-hr	24.50	29.61	24.24	30.44	20.20	22.35	20.11	23.51	0.00	0.019
	3-hr	22.05	26.65	21.82	27.40	18.18	20.11	18.10	21.16	0.00	0.017
	24-hr	6.12	7.40	6.06	7.61	5.05	5.59	5.03	5.88	0.00	0.0048
	Annual	1.78	2.15	1.76	2.21	1.47	1.63	1.46	1.71	0.00	0.0015
PM10	1-hr	20.41	24.67	20.20	25.37	16.83	18.62	16.76	19.59	1.17	0.52
	24-hr	5.10	6.17	5.05	6.34	4.21	4.66	4.19	4.90	0.29	0.130
	Annual	1.48	1.79	1.47	1.84	1.22	1.35	1.22	1.42	0.094	0.042
PM2.5	1-hr	20.41	24.67	20.20	25.37	16.83	18.62	16.76	19.59	1.17	0.52
	24-hr	5.10	6.17	5.05	6.34	4.21	4.66	4.19	4.90	0.29	0.130
	Annual	1.48	1.79	1.47	1.84	1.22	1.35	1.22	1.42	0.094	0.042
Cavity Screening - Unit Emission Rate Impacts											
Emissions (g/sec)		1	1	1	1	1	1	1	1	1	1
1-hr Conc (ug/m3)		40.41	40.45	40.41	40.41	50.7	57.45	43.51	49.08	573.4	684.9
Cavity Screening - Maximum Emission Rate Impacts											
NOx	1-hr	313.20	313.51	340.42	340.42	275.74	312.45	257.20	290.13	0.00	135.19
	Annual	22.78	22.80	24.76	24.76	20.05	22.72	18.71	21.10	0.00	10.82
CO	1-hr	391.50	391.89	425.52	425.52	344.68	390.56	321.50	362.66	0.00	87.08
	8-hr	274.05	274.32	297.87	297.87	241.27	273.39	225.05	253.86	0.00	60.95
SO2	1-hr	62.64	62.70	68.08	68.08	55.15	62.49	51.44	58.03	0.00	0.27
	3-hr	56.38	56.43	61.28	61.28	49.63	56.24	46.30	52.22	0.00	0.24
	24-hr	25.06	25.08	27.23	27.23	22.06	25.00	20.58	23.21	0.00	0.11
	Annual	4.56	4.56	4.95	4.95	4.01	4.54	3.74	4.22	0.00	0.021
PM10	1-hr	52.20	52.25	56.74	56.74	45.96	52.08	42.87	48.35	21.69	7.25
	24-hr	20.88	20.90	22.69	22.69	18.38	20.83	17.15	19.34	8.68	2.90
	Annual	3.80	3.80	4.13	4.13	3.34	3.79	3.12	3.52	1.74	0.58
PM2.5	1-hr	52.20	52.25	56.74	56.74	45.96	52.08	42.87	48.35	21.69	7.25
	24-hr	20.88	20.90	22.69	22.69	18.38	20.83	17.15	19.34	8.68	2.90
	Annual	3.80	3.80	4.13	4.13	3.34	3.79	3.12	3.52	1.74	0.58

Table 7.9a
SCREEN3 Class I Modeling Results
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Cooling Tower	Fire Pump
Load (%)		Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	100	100
Ambient Temp (F)		60	60	60	60	60	60	60	60		
Fuel Moisture (%)		37.6	37.6	50	50	37.6	37.6	50	50		
Stack Temperature (F)		369	260	366	260	375	260	370	260		
Maximum Emission Rates (lb/hr)											
NOx		61.51	61.51	66.86	66.86	43.16	43.16	46.92	46.92	0.00	1.57
CO		76.89	76.89	83.57	83.57	53.96	53.96	58.64	58.64	0.00	1.01
SO2		12.30	12.30	13.37	13.37	8.63	8.63	9.38	9.38	0.00	0.0031
PM10		10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	0.30	0.084
PM2.5		10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82	0.30	0.084
Maximum Emission Rates (g/sec)											
NOx		7.75	7.75	8.42	8.42	5.44	5.44	5.91	5.91	0.00	0.197
CO		9.69	9.69	10.53	10.53	6.80	6.80	7.39	7.39	0.00	0.127
SO2		1.55	1.55	1.68	1.68	1.09	1.09	1.18	1.18	0.00	0.00039
PM10		1.29	1.29	1.40	1.40	0.91	0.91	0.99	0.99	0.038	0.0106
PM2.5		1.29	1.29	1.40	1.40	0.91	0.91	0.99	0.99	0.038	0.0106
Simple Terrain Screening - Unit Emission Rate Impacts											
Emissions (g/sec)		1	1	1	1	1	1	1	1	1	1
1-hr Conc (ug/m3)		0.92	1.22	1.02	1.34	1.15	1.48	1.26	1.60	3.43	10.66
Simple Terrain Screening - Maximum Emission Rate Impacts											
NOx	1-hr	7.12	9.46	8.62	11.27	6.27	8.04	7.42	9.43	0.00	2.10
	Annual	0.52	0.69	0.63	0.82	0.46	0.58	0.54	0.69	0.00	0.17
CO	1-hr	8.90	11.83	10.77	14.09	7.83	10.05	9.28	11.79	0.00	1.36
	8-hr	6.23	8.28	7.54	9.86	5.48	7.03	6.50	8.26	0.00	0.95
SO2	1-hr	1.42	1.89	1.72	2.25	1.25	1.61	1.48	1.89	0.00	0.0042
	3-hr	1.28	1.70	1.55	2.03	1.13	1.45	1.34	1.70	0.00	0.0037
	24-hr	0.57	0.76	0.69	0.90	0.50	0.64	0.59	0.75	0.00	0.0017
	Annual	0.10	0.14	0.13	0.16	0.09	0.12	0.11	0.14	0.00	0.00033
PM10	1-hr	1.19	1.58	1.44	1.88	1.04	1.34	1.24	1.57	0.13	0.113
	24-hr	0.47	0.63	0.57	0.75	0.42	0.54	0.49	0.63	0.052	0.045
	Annual	0.09	0.11	0.10	0.14	0.08	0.10	0.09	0.11	0.010	0.0090
PM2.5	1-hr	1.19	1.58	1.44	1.88	1.04	1.34	1.24	1.57	0.13	0.113
	24-hr	0.47	0.63	0.57	0.75	0.42	0.54	0.49	0.63	0.052	0.045
	Annual	0.09	0.11	0.10	0.14	0.08	0.10	0.09	0.11	0.010	0.0090
Complex Terrain Screening - Unit Emission Rate Impacts											
Emissions (g/sec)		1	1	1	1	1	1	1	1	1	1
1-hr Conc (ug/m3)		0.68	0.70	0.67	0.69	0.69	0.71	0.69	0.70	0.71	0.76
24-hr Conc (ug/m3)		0.17	0.17	0.17	0.17	0.17	0.18	0.17	0.18	0.18	0.19
Complex Terrain Screening - Maximum Emission Rate Impacts											
NOx	1-hr	5.26	5.41	5.65	5.82	3.77	3.86	4.06	4.17	0.00	0.15
	Annual	0.38	0.39	0.41	0.42	0.27	0.28	0.30	0.30	0.00	0.012
CO	1-hr	6.57	6.76	7.06	7.28	4.71	4.83	5.07	5.21	0.00	0.097
	8-hr	4.60	4.73	4.94	5.09	3.30	3.38	3.55	3.65	0.00	0.068
SO2	1-hr	1.05	1.08	1.13	1.16	0.75	0.77	0.81	0.83	0.00	0.00030
	3-hr	0.95	0.97	1.02	1.05	0.68	0.70	0.73	0.75	0.00	0.00027
	24-hr	0.26	0.27	0.28	0.29	0.19	0.19	0.20	0.21	0.00	0.000074
	Annual	0.08	0.08	0.08	0.08	0.05	0.06	0.06	0.06	0.00	0.000024
PM10	1-hr	0.88	0.90	0.94	0.97	0.63	0.64	0.68	0.69	0.027	0.0080
	24-hr	0.22	0.23	0.24	0.24	0.16	0.16	0.17	0.17	0.0067	0.00201
	Annual	0.064	0.066	0.068	0.071	0.046	0.047	0.049	0.051	0.0021	0.00064
PM2.5	1-hr	0.88	0.90	0.94	0.97	0.63	0.64	0.68	0.69	0.03	0.0080
	24-hr	0.22	0.23	0.24	0.24	0.16	0.16	0.17	0.17	0.01	0.00201
	Annual	0.064	0.066	0.068	0.071	0.046	0.047	0.049	0.051	0.0021	0.00064

Table 7.10
Comparison of Class II Screening Concentrations to Significant Impact Levels
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Cooling Tower	Firepump	Total	SIL
Load (%)		Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	100	100		
Ambient Temp (F)		60	60	60	60	60	60	60	60				
Fuel Moisture (%)		37.6	37.6	50	50	37.6	37.6	50	50				
Stack Temperature (F)		369	260	366	260	375	260	370	260				
For Potential Combined Impacts													
Hours/3-hr Period		3	3	3	3	3	3	3	3	3	1		
Hours/8-hr Period		8	8	8	8	8	8	8	8	8	1		
Hours/24-hr Period		24	24	24	24	24	24	24	24	24	1		
Hours/8,760-hr Period		8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	500		
NOx	Annual	22.76	22.80	24.76	24.76	20.05	22.72	18.71	21.10	0.00	0.65	25.4	1
CO	1-hr	391.50	391.89	425.52	425.52	344.68	390.56	321.50	362.66	0.00	92.02	517.5	2000
	8-hr	274.05	274.32	297.87	297.87	241.27	273.39	225.05	253.86	0.00	8.05	305.9	500
SO2	3-hr	56.38	56.43	61.28	61.28	49.63	56.24	46.30	52.22	0.00	0.085	61.4	25
	24-hr	25.06	25.08	27.23	27.23	22.06	25.00	20.58	23.21	0.00	0.0047	27.2	5
	Annual	4.56	4.56	4.95	4.95	4.01	4.54	3.74	4.22	0.00	0.00129	5.0	1
PM10	24-hr	20.88	20.90	22.69	22.69	18.38	20.83	17.15	19.34	8.68	0.128	31.5	5
	Annual	3.80	3.80	4.13	4.13	3.34	3.79	3.12	3.52	1.74	0.035	5.9	1
PM2.5	24-hr	20.88	20.90	22.69	22.69	18.38	20.83	17.15	19.34	8.68	0.128	31.5	2
	Annual	3.80	3.80	4.13	4.13	3.34	3.79	3.12	3.52	1.74	0.035	5.9	0.3

Notes:
Individual source impacts reflect annual and short-term operating restrictions
Potential combined short-term values are based on 1-hour per day operation of the fire pump

Table 7.10a
Comparison of Class I Screening Concentrations to Significant Impact Levels
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Cooling Tower	Firepump	Total	SIL
Load (%)		Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	100	100		
Ambient Temp (F)		60	60	60	60	60	60	60	60				
Fuel Moisture (%)		37.6	37.6	50	50	37.6	37.6	50	50				
Stack Temperature (F)		369	260	366	260	375	260	370	260				
For Potential Combined Impacts													
Hours/3-hr Period		3	3	3	3	3	3	3	3	3	1		
Hours/8-hr Period		8	8	8	8	8	8	8	8	8	1		
Hours/24-hr Period		24	24	24	24	24	24	24	24	24	1		
Hours/8,760-hr Period		8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	500		
NOx	Annual	0.52	0.69	0.63	0.82	0.46	0.58	0.54	0.69	0.00	0.010	0.83	0.1
CO	1-hr	8.90	11.83	10.77	14.09	7.83	10.05	9.28	11.79	0.00	1.36	15.44	NA
	8-hr	6.23	8.28	7.54	9.86	5.48	7.03	6.50	8.26	0.00	0.119	9.98	NA
SO2	3-hr	1.28	1.70	1.55	2.03	1.13	1.45	1.34	1.70	0.00	0.0012	2.03	1.0
	24-hr	0.57	0.76	0.69	0.90	0.50	0.64	0.59	0.75	0.00	0.000069	0.90	0.2
	Annual	0.10	0.14	0.13	0.16	0.09	0.12	0.11	0.14	0.00	0.000019	0.16	0.08
PM10	24-hr	0.47	0.63	0.57	0.75	0.42	0.54	0.49	0.63	0.052	0.00188	0.81	0.32
	Annual	0.09	0.11	0.10	0.14	0.08	0.10	0.09	0.11	0.010	0.00052	0.15	0.16
PM2.5	24-hr	0.47	0.63	0.57	0.75	0.42	0.54	0.49	0.63	0.052	0.00188	0.81	0.13
	Annual	3.80	3.80	4.13	4.13	3.34	3.79	3.12	3.52	1.74	0.00052	5.86	0.06

Notes:
Individual source impacts reflect annual and short-term operating restrictions
Potential combined short-term values are based on 1-hour per day operation of the fire pump

Table 7.11
Class II Analysis
Refined Modeling - Individual Source Contributions and Cumulative Impacts[1]
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Cooling Tower	Firepump		
Load (%)		100	100	100	100		
Fuel Moisture %		37.6	50				
Exit Temp		260	260				
Hours/Day		24	24	24	1		
Hours/Year		8760	8760	8760	500		
Maximum Emission Rates (g/sec)							
NOx		7.75	8.42	0.00	0.20		
CO		9.69	10.53	0.00	0.127		
SO2		1.55	1.68	0.00	0.00039		
PM10		1.29	1.40	0.038	0.0106		
PM2.5		1.29	1.40	0.038	0.0106		
AERMOD Results @ 1 g/sec Emission Rate							
1-hr		4.6320	4.1816	36.4912	568.9352		
3-hr		3.0127	2.6382	19.7771	357.7489		
8-hr		1.9988	1.7664	10.7709	304.0025		
24-hr		0.7292	0.6415	5.8850	185.6001		
Annual		0.0837	0.0772	0.3048	24.9397		
AERMOD Results @ Maximum Emission Rates						**Total**	**SIL**
NOx	Annual	0.59	0.59	0.00	0.28	0.87	1
NO2	Annual	0.44	0.44	0.00	0.21	0.65	1
CO	1-hr	44.88	44.03	0.00	72.33	117.21	2000
CO	8-hr	19.36	18.60	0.00	9.04	28.41	500
SO2	3-hr	4.67	4.44	0.00	0.07	4.74	25
SO2	24-hr	1.13	1.08	0.00	0.009	1.14	5
SO2	Annual	0.12	0.12	0.00	0.00056	0.12	1
PM10	24-hr	0.94	0.90	0.22	0.25	1.42	5
PM10	Annual	0.10	0.10	0.012	0.0151	0.13	1
PM2.5	24-hr	0.94	0.90	0.22	0.25	1.42	2
PM2.5	Annual	0.10	0.10	0.012	0.0151	0.13	0.3

1 - Cumulative impacts conservatively assume that all sources have maximum impact at the same location

2 - Short term total impacts are based on the maximum boiler and cooling tower impacts with 1 hour of maintenance of the firepump.

3 - Annual NO_X impact adjusted by the Ambient Ratio Method factor of 0.75 to get the NO_2 concentration.

Table 7.11a
Onsite Analysis
Refined Modeling - Individual Source Contributions and Cumulative Impacts[1]
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Cooling Tower	Firepump		
Load (%)		100	100	100	100		
Fuel Moisture %		37.6	50				
Exit Temp		260	260				
Hours/Day		24	24	24	1		
Hours/Year		8760	8760	8760	500		
Maximum Emission Rates (g/sec)							
NOx		7.75	8.42	0.00	0.20		
CO		9.69	10.53	0.00	0.127		
SO2		1.55	1.68	0.00	0.00039		
PM10		1.29	1.40	0.038	0.0106		
PM2.5		1.29	1.40	0.038	0.0106		
AERMOD Results @ 1 g/sec Emission Rate							
1-hr		4.4742	4.0203	67.6821	439.5999		
3-hr		1.5078	1.3534	45.2222	308.8453		
8-hr		0.7382	0.7125	28.6904	255.7844		
24-hr		0.2685	0.2592	15.4373	154.5200		
Annual		0.0283	0.0254	0.5333	24.2184		
AERMOD Results @ Maximum Emission Rates						**Total**	**SIL**
NOx	Annual	0.20	0.19	0.00	0.27	0.47	1
NO2	Annual	0.15	0.15	0.00	0.20	0.35	1
CO	1-hr	43.35	42.33	0.00	55.89	99.24	2000
CO	8-hr	7.15	7.50	0.00	6.99	14.49	500
SO2	3-hr	2.34	2.28	0.00	0.06	2.39	25
SO2	24-hr	0.42	0.44	0.00	0.007	0.44	5
SO2	Annual	0.04	0.04	0.00	0.00054	0.04	1
PM10	24-hr	0.35	0.36	0.58	0.19	1.14	5
PM10	Annual	0.03	0.03	0.020	0.0146	0.07	1
PM2.5	24-hr	0.35	0.36	0.58	0.19	1.14	2
PM2.5	Annual	0.03	0.03	0.020	0.0146	0.07	0.3

1 - Cumulative impacts conservatively assume that all sources have maximum impact at the same location of the firepump.
3 - Annual NO_X impact adjusted by the Ambient Ratio Method factor of 0.75 to get the NO_2 concentration.

Table 7.12
Class I Analysis
Refined Modeling - Individual Source Contributions and Cumulative Impacts[1]
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Cooling Tower	Firepump	Total	SIL
Load (%)		100	100	100	100		
Fuel Moisture %		37.6	50				
Exit Temp		260	260				
Hours/Day		24	24	24	1		
Hours/Year		8760	8760	8760	500		
Maximum Emission Rates (g/sec)							
NOx		7.75	8.42	0.00	0.20		
CO		9.69	10.53	0.00	0.127		
SO2		1.55	1.68	0.00	0.00039		
PM10		1.29	1.40	0.038	0.0106		
PM2.5		1.29	1.40	0.038	0.0106		
AERMOD Results @ 1 g/sec Emission Rate							
1-hr		1.1427	1.0436	1.0537	1.9852		
3-hr		0.6431	0.5930	0.6344	0.9773		
8-hr		0.3074	0.2828	0.3099	0.4925		
24-hr		0.1159	0.1116	0.1271	0.1936		
Annual		0.0139	0.0136	0.0132	0.0192		
AERMOD Results @ Maximum Emission Rates						**Total**	**SIL**
NOx	Annual	0.10	0.10	0.00	0.00022	0.10	0.1
NO2	Annual	0.074	0.078	0.00	0.00016	0.078	0.1
CO	1-hr	11.07	10.99	0.00	0.252	11.32	NA
CO	8-hr	2.98	2.98	0.00	0.0315	3.01	NA
SO2	3-hr	1.00	1.00	0.00	0.00026	1.00	1.0
SO2	24-hr	0.18	0.19	0.00	0.000032	0.19	0.2
SO2	Annual	0.020	0.021	0.00	0.00000043	0.02	0.08
PM10	24-hr	0.15	0.16	0.0048	0.00088	0.16	0.32
PM10	Annual	0.016	0.017	0.00050	0.0000116	0.02	0.16
PM2.5	24-hr	0.15	0.16	0.0048	0.00088	0.16	0.13
PM2.5	Annual	0.016	0.017	0.00050	0.0000116	0.02	0.06

1 - Cumulative impacts conservatively assume that all sources have maximum impact at the same location

2 - Short term total impacts are based on the maximum boiler and cooling tower impacts with 1 hour of maintenance of the firepump.

3 - Annual NO_X impact adjusted by the Ambient Ratio Method factor of 0.75 to get the NO_2 concentration.

4 - SILs provided by NHDES

Table 7.12a
Class I Analysis
Refined Modeling - Laidlaw Boiler with Other PSD Increment-Consuming Source
Berlin BioPower - Berlin, New Hampshire

AERMOD Results @ Maximum Emission Rates					**Total**	**PSD**
Pollutant	Averaging	Rank	Laidlaw and	Fire Pump		**Increment**
	Period		Other PSD Sources[1]	Maintenance[2]		
SO2	3-hr	Max	7.95	0.057		
SO2	3-hr	H2H	4.00		4.06	25
PM2.5	24-hr	Max	0.35	0.194		
PM2.5	24-hr	H2H	0.25		0.44	2

1 - Laidlaw boiler and cooling tower were modeled with increment-consuming sources provided by DES

2 - Maximum Class I impacts from 1 hour of maintenance of the firepump were added to the other modeled values, regardless of time or location.

Table 7.13
Monitor Background Concentrations
Berlin BioPower – Berlin, New Hampshire

Pollutant	Averaging Period	Concentration (μg/m³)	Monitoring Site	Years of Data
CO	1-hr	0	Assume zero background	
	8-hr	0	Assume zero background	
NO_2	1-hr	53	Brentwood	2001-2003
	Annual	15	Brentwood	2001-2003
$PM_{2.5}$	24-hr	21	Claremont	2006-2008
	Annual	9	Claremont	2006-2008
PM_{10}	24-hr	30	Claremont	2000-2002
SO_2	3-hr	79	Claremont	2000-2002
	24-hr	39	Claremont	2000-2002
	Annual	16	Claremont	2000-2002

Notes: 1. Background values provided by DES

Table 7.14
Comparison of Maximum Pollutant Concentrations to NAAQS
Berlin BioPower – Berlin, New Hampshire

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)			NAAQS ($\mu g/m^3$)
		Modeled	Background	Total	
NO_2	1-hour	81.7	53	134.7	188.9
	Annual	0.65	15	16	100
CO	1-hour	117.2	0	117	40,000
	8-hour	28.4	0	28	10,000
SO_2	3-hour	4.74	79	84	1300
	24-hour	1.14	39	40	365
	Annual	0.12	16	16	80
PM_{10}	24-hour	1.42	30	31	150
$PM_{2.5}$	24-hour	1.42	21	22	35
	Annual	0.13	9	9	15

Table 7.15
RTAP Compliance Analysis
Berlin BioPower - Berlin, New Hampshire

Source	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Boiler	Cooling Tower		
Load (%)	Max (100%)	Max (100%)	Max (100%)	Max (100%)	Min (70%)	Min (70%)	Min (70%)	Min (70%)	100		
Ambient Temp (F)	60	60	60	60	60	60	60	60			
Fuel Moisture (%)	37.6	37.6	50	50	37.6	37.6	50	50			
Stack Temperature (F)	369	260	366	260	375	260	370	260			
Heat Input Rate (MMBtu/hr)	932	932	1,013	1,013	654	654	711	711			
NH3 Emission Rate (lb/MMBtu)	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012			
NH3 Emission Rate (lb/hr)	11.18	11.18	12.16	12.16	7.85	7.85	8.53	8.53			
NH3 Emission Rate (g/sec)	1.41	1.41	1.53	1.53	0.99	0.99	1.07	1.07			
Chlorine Emission Rate (lb/hr)									0.496		
Chlorine Emission Rate (g/sec)									0.062		
	Maximum Impacts @ 1 g/sec										
1-hr Conc (ug/m^3)	15.80	19.10	14.39	18.07	18.57	20.54	17.01	19.88	36.49		
24-hr Conc (ug/m^3)	3.95	4.78	3.60	4.52	4.64	5.14	4.25	4.97	5.89		
Ammonia	µg/m^3									AAL	Pass/Fail
1-hr	22.27	26.92	22.04	27.67	18.36	20.31	18.28	21.37	N/A	N/A	N/A
24-hr	5.57	6.73	5.51	6.92	4.59	5.08	4.57	5.34	N/A	100	Pass
Annual	1.78	2.15	1.76	2.21	1.47	1.63	1.46	1.71	N/A	100	Pass
Chlorine	µg/m^3									AAL	Pass/Fail
1-hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.28	N/A	N/A
24-hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.37	7.5	Pass
Annual	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.18	7.5	Pass

Table 7.16
SCREEN3 Start-Up Conditions
Berlin BioPower - Berlin, New Hampshire

Startup Phase		Phase 1	Phase 2	Phase 3
Startup Phase Duration (hours)		8	3	1
Boiler Fuel		ULSD	ULSD + Wood	Wood
Maximum Emission Rates (lb/hr)				
NOx		48.00	37.98	33.55
CO		120.00	77.48	41.94
SO2		0.48	3.04	6.71
PM10		12.00	8.33	5.59
PM2.5		12.00	8.33	5.59
Maximum Emission Rates (g/sec)				
NOx		6.05	4.79	4.23
CO		15.12	9.76	5.28
SO2		0.06	0.38	0.85
PM10		1.51	1.05	0.70
PM2.5		1.51	1.05	0.70
Simple Terrain Screening - Unit Emission Rate Impacts				
Emissions (g/sec)		1	1	1
1-hr Conc (ug/m3)		12.78	11.44	7.42
Simple Terrain Screening - Maximum Emission Rate Impacts				
NOx	1-hr	77.29	54.75	31.36
	Annual	0.03	0.01	0.00
CO	1-hr	193.23	111.68	39.21
	8-hr	135.26	29.31	3.43
SO2	1-hr	0.77	4.38	6.27
	3-hr	0.70	3.94	1.88
	24-hr	0.10	0.22	0.10
	Annual	0.00	0.00	0.00
PM10	1-hr	19.32	12.01	5.23
	24-hr	2.58	0.60	0.09
	Annual	0.01	0.00	0.00
PM2.5	1-hr	19.32	12.01	5.23
	24-hr	2.58	0.60	0.09
	Annual	0.01	0.00	0.00
Complex Terrain Screening - Unit Emission Rate Impacts				
Emissions (g/sec)		1	1	1
1-hr Conc (ug/m3)		20.79	20.08	17.95
24-hr Conc (ug/m3)		5.20	5.02	4.49
Complex Terrain Screening - Maximum Emission Rate Impacts				
NOx	1-hr	125.73	96.11	75.88
	Annual	0.06	0.02	0.00
CO	1-hr	314.31	196.06	94.85
	8-hr	220.02	51.46	8.30
SO2	1-hr	1.26	7.68	15.18
	3-hr	1.13	6.91	4.55
	24-hr	0.31	0.96	0.63
	Annual	0.00	0.00	0.00
PM10	1-hr	31.43	21.08	12.65
	24-hr	7.86	2.63	0.53
	Annual	0.01	0.00	0.00
PM2.5	1-hr	31.43	21.08	12.65
	24-hr	7.86	2.63	0.53
	Annual	0.01	0.00	0.00
Cavity Screening - Unit Emission Rate Impacts				
Emissions (g/sec)		1	1	1
1-hr Conc (ug/m3)		70.31	59.17	40.41
Cavity Screening - Maximum Emission Rate Impacts				
NOx	1-hr	425.23	283.16	170.84
	Annual	0.19	0.05	0.01
CO	1-hr	1063.09	577.61	213.54
	8-hr	744.16	151.62	18.69
SO2	1-hr	4.25	22.63	34.17
	3-hr	3.83	20.37	10.25
	24-hr	0.57	1.13	0.57
	Annual	0.00	0.00	0.00
PM10	1-hr	106.31	62.10	28.47
	24-hr	14.17	3.11	0.47
	Annual	0.05	0.01	0.00
PM2.5	1-hr	106.31	62.10	28.47
	24-hr	14.17	3.11	0.47
	Annual	0.05	0.01	0.00

Start-ups/Year 6

Table 7.17
Comparison of Class II Screening Concentrations Including Boiler Startup Events to Significant Impact Levels
Berlin BioPower - Berlin, New Hampshire

Startup Phase		Phase 1	Phase 2	Phase 3	Total Startup	Non-Startup	Total	SIL
Startup Phase Duration (hours)		8	3	1		(from refined)		
Boiler Fuel		ULSD	ULSD + Wood	Wood				
Fuel Moisture (%)		37.6	37.6	50				
Stack Temperature (F)		369	260	366				
NOx	Annual	0.19	0.05	0.01	0.24	0.87	1.115	1
NO2	Annual	0.14	0.03	0.01	0.18	0.65	0.836	1
CO	1-hr	1063.09	577.61	213.54	1063.09	n/a	1063.1	2000
	8-hr	744.16	151.62	18.69	744.16	n/a	744.2	500
SO2	3-hr	3.83	20.37	10.25	20.37	n/a	20.4	25
	24-hr	0.57	1.13	0.63	2.3310	1.14	3.5	5
	Annual	0.00	0.00	0.00	0.0075	0.12	0.1	1
PM10	24-hr	14.17	3.11	0.53	17.8066	1.42	19.2	5
	Annual	0.05	0.01	0.00	0.0584	0.13	0.2	1
PM2.5	24-hr	14.17	3.11	0.53	17.8066	1.42	19.2	2
	Annual	0.05	0.01	0.00	0.0584	0.13	0.2	0.3

Notes:
Maximum operations from the boiler were added to the worst-case start-up impacts for 24-hour and annual periods
Boiler impacts were no adjusted to reflect start-up hours

Table 7.18
Class II Analysis
Refined Modeling - Individual Source Contributions and Cumulative Impacts Including Boiler Startup[1]
Berlin BioPower - Berlin, New Hampshire

Source		Boiler	Boiler	Cooling Tower	Phase 1	Phase 2	Phase 3		
Load (%)		100	100	100					
Fuel Moisture %		37.6	50						
Exit Temp		260	260						
Hours/Day		12	12	12	8	3	1		
Hours/Year		8760	8760	8760		300	300		
Maximum Emission Rates (g/sec)									
CO		9.69	10.53	0.00	15.12	9.76	5.28		
PM10		1.29	1.40	0.038	1.51	1.05	0.70		
PM2.5		1.29	1.40	0.038	1.51	1.05	0.70		
AERMOD Results @ 1 g/sec Emission Rate									
1-hr		n/a	n/a	n/a	n/a	n/a	4.2746		
3-hr		n/a	n/a	n/a	n/a	3.5625	n/a		
8-hr		n/a	n/a	n/a	2.8340	n/a	n/a		
12-hr		1.1004	1.2404	18.1700	n/a	n/a	n/a		
AERMOD Results @ Maximum Emission Rates								**Total**	**SIL**
CO	8-hr	n/a	n/a	n/a	42.85	n/a	n/a	42.85	500
PM10	24-hr	0.71	0.87	0.3437	1.4284	0.4674	0.1255	3.24	5
PM2.5	24-hr	0.71	0.87	0.3437	1.4284	0.4674	0.1255	3.24	2

Combined onsite and offsite receptors

Table 7.19
Class II Analysis
Refined Modeling - 24-Hour PM2.5 Impacts During Start-Up
Berlin BioPower - Berlin, New Hampshire

Start-Up Beginning Hour	Total Modeled Concentration (ug/m3) Boiler Firing 50% Moisture Fuel	Boiler Firing 37.6% Moisture Fuel
1	1.3	1.29
2	1.29	1.29
3	1.17	1.19
4	1.17	1.19
5	1.08	1.09
6	1.1	1.13
7	1.08	1.11
8	1.04	1.07
9	1.14	1.15
10	1.21	1.23
11	1.21	1.23
12	1.22	1.24
13	1.22	1.23
14	1.22	1.23
15	1.2	1.21
16	1.18	1.2
17	1.15	1.14
18	1.2	1.2
19	1.2	1.2
20	1.17	1.17
21	1.23	1.22
22	1.3	1.28
23	1.34	1.35
24	1.33	1.33
SIL	2	2

Table 7.20
Comparison of Maximum Pollutant Concentrations to Vegetation Sensitivity Concentrations
Berlin BioPower – Berlin, New Hampshire

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)			Vegetation Sensitivity Concentration ($\mu g/m^3$)		
		Modeled	Background	Total	Sensitive	Intermediate	Resistant
SO_2	1-hour	7.4	237[4]	244	917	-	-
	3-hour	4.7	79	84	786	2096	13100
	Annual	0.13	16	16	18	18	18
NO_2	4-hour	60.8	53[2]	114	3760	9400	16920
	8-hour	29.5	53[2]	83	3760	7520	15040
	Monthly	10.3	53[2]	63	564	564	564
	Annual	0.65	15	16	94	94	94
CO	Weekly	10.1	0	10.1	1800000	-	18000000
Beryllium	Monthly	0.0001	-[5]	0.0001	0.01	0.01	0.01
Lead	Quarterly	0.0045	0.02	0.02	1.5	1.5	1.5

1. Modeled 4-hour concentration based on a 3-hour averaging period.
2. Monitored 4-hour, 8-hour and monthly NO_2 values based on a 1-hour averaging period.
3. Modeled monthly, weekly and quarterly concentrations based on a 24-hour averaging period.
4. Monitored 1-hour SO_2 background assumed as three times the 3-hour SO_2 background.
5. Beryllium values are not reported on the AIRS website.

Table 3.1
Maximum Stack Concentrations & Emission Rates
Berlin BioPower - Berlin, New Hampshire

Pollutant	Biomass Boiler Normal Operation			Fire Pump	Cooling Tower
	Wood Fuel			Diesel	
	ppm@7%O_2	lb/MMBtu	lb/hr	lb/hr	lb/hr
NO_x	36.0	0.060	66.9	1.6	
CO	74.0	0.075	83.6	1.0	
SO_2	5.0	0.012	13.4	0.0031	
H_2SO_4		0.004	4.5		
PM (filterable)		0.010	11.1	0.084	0.30
PM_{10} (filterable)		0.010	11.1	0.084	0.30
$PM_{2.5}$ (filterable)		0.010	11.1	0.084	0.30
NH_3	20.0	0.012	13.4		
VOC	17.0	0.010	11.1	0.055	
Formaldehyde		0.0044	4.9	0.0022	
Hydrogen Chloride		0.00083	0.92		
Lead		0.000048	0.1		
Mercury		0.0000030	0.0		

(1) The biomass boiler maximum stack concentrations and emission rates during normal operation do not apply at less than 70% of maximum load.
(2) The maximum lb/hr emission rates for the boiler are derived from the lb/MMBtu emission rate, the maximum heat input rate (1,013 MMBtu/hr), and a factor of 10% to account for expected variability in the exhaust gas volumetric flow rate from the boiler.

Potential Emissions Summary
Biomass Boiler - Normal Operation
Berlin BioPower - Berlin, New Hampshire

Biomass Boiler		
Parameter	Wood Fuel	
Annual Operation	8,688	hr/yr
Heat Input Rate @ 100% Load (37.6% fuel H2O, 60F ambient)	932	MMBtu/hr
Fuel Heat Rate (HHV)	5,061.0	Btu/lb
Fuel Input Rate	92.1	ton/hr

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
NOx		B&W	lb/MMBtu	0.060	55.9	485,833	242.9
CO		B&W	lb/MMBtu	0.075	69.9	607,291	303.6
SO2		B&W	lb/MMBtu	0.012	11.2	97,167	48.6
H2SO4 (assumes 10% SO2:SO3 Conv.)		Assumed	lb/MMBtu	0.002	1.7	14,879	7.4
PM (filterable)		B&W	lb/MMBtu	0.010	9.3	80,972	40.5
PM10 (filterable)		B&W	lb/MMBtu	0.010	9.3	80,972	40.5
PM2.5 (filterable)		B&W	lb/MMBtu	0.010	9.3	80,972	40.5
CO2		B&W	lb/MMBtu	221.0	206,000	1,789,728,000	894,864
NH3 (assumes 20 ppm slip)		Assumed	lb/MMBtu	0.012	11.4	99,064	49.5
VOC		B&W	lb/MMBtu	0.010	9.3	80,972	40.5
Antimony (HAP)	X	AP-42	lb/MMBtu	7.9E-06	7.4E-03	64	0.032
Arsenic (HAP)	X	AP-42	lb/MMBtu	2.2E-05	2.1E-02	178	0.089
Barium		AP-42	lb/MMBtu	1.7E-04	1.6E-01	1,377	0.688
Beryllium (HAP)	X	AP-42	lb/MMBtu	1.1E-06	1.0E-03	9	0.004
Cadmium (HAP)	X	AP-42	lb/MMBtu	4.1E-06	3.8E-03	33	0.017
Chromium, Total (HAP)	X	AP-42	lb/MMBtu	2.1E-05	2.0E-02	170	0.085
Cobalt (HAP)	X	AP-42	lb/MMBtu	6.5E-06	6.1E-03	53	0.026
Copper		AP-42	lb/MMBtu	4.9E-05	4.6E-02	397	0.198
Iron		AP-42	lb/MMBtu	9.9E-04	9.2E-01	8,016	4.008
Lead (HAP)	X	AP-42	lb/MMBtu	4.8E-05	4.5E-02	389	0.194
Manganese (HAP)	X	AP-42	lb/MMBtu	1.6E-03	1.5E+00	12,956	6.478
Mercury (HAP)	X	MACT	lb/MMBtu	3.0E-06	2.8E-03	24	0.012
Molybdenum		AP-42	lb/MMBtu	2.1E-06	2.0E-03	17	0.009
Nickel (HAP)	X	AP-42	lb/MMBtu	3.3E-05	3.1E-02	267	0.134
Phosphorous		AP-42	lb/MMBtu	2.7E-05	2.5E-02	219	0.109
Potassium		AP-42	lb/MMBtu	3.9E-02	3.6E+01	315,791	157.896
Selenium (HAP)	X	AP-42	lb/MMBtu	2.8E-06	2.6E-03	23	0.011
Silver		AP-42	lb/MMBtu	1.7E-03	1.6E+00	13,765	6.883
Sodium		AP-42	lb/MMBtu	3.6E-04	3.4E-01	2,915	1.457
Strontium		AP-42	lb/MMBtu	1.0E-05	9.3E-03	81	0.040
Tin		AP-42	lb/MMBtu	2.3E-05	2.1E-02	186	0.093
Titanium		AP-42	lb/MMBtu	2.0E-05	1.9E-02	162	0.081
Vanadium		AP-42	lb/MMBtu	9.8E-07	9.1E-04	8	0.004
Yttrium		AP-42	lb/MMBtu	3.0E-07	2.8E-04	2	0.001
Zinc		AP-42	lb/MMBtu	4.2E-04	3.9E-01	3,401	1.700
Acenaphthene		AP-42	lb/MMBtu	9.1E-07	8.5E-04	7	0.004
Acenaphthylene		AP-42	lb/MMBtu	5.0E-06	4.7E-03	40	0.020
Acetaldehyde (HAP)	X	AP-42	lb/MMBtu	8.3E-04	7.7E-01	6,721	3.360
Acetone		AP-42	lb/MMBtu	1.9E-04	1.8E-01	1,538	0.769
Acetophenone (HAP)	X	AP-42	lb/MMBtu	3.2E-09	3.0E-06	0	0.000
Acrolein (HAP)	X	Bridgewater	lb/MMBtu	4.3E-05	4.0E-02	348	0.174
Anthracene		AP-42	lb/MMBtu	3.0E-06	2.8E-03	24	0.012
Benzaldehyde		AP-42	lb/MMBtu	8.5E-07	7.9E-04	7	0.003
Benzene (HAP)	X	AP-42	lb/MMBtu	4.2E-03	3.9E+00	34,008	17.004
Benzo(a)anthracene		AP-42	lb/MMBtu	6.5E-08	6.1E-05	1	0.000
Benzo(a)pyrene		AP-42	lb/MMBtu	2.6E-06	2.4E-03	21	0.011
Benzo(b)fluoranthene		AP-42	lb/MMBtu	1.0E-07	9.3E-05	1	0.000
Benzo(e)pyrene		AP-42	lb/MMBtu	2.6E-09	2.4E-06	0	0.000
Benzo(g,h,i)perylene		AP-42	lb/MMBtu	9.3E-08	8.7E-05	1	0.000
Benzo(j,k)fluoranthene		AP-42	lb/MMBtu	1.6E-07	1.5E-04	1	0.001
Benzo(k)fluoranthene		AP-42	lb/MMBtu	3.6E-08	3.4E-05	0	0.000
Benzoic acid		AP-42	lb/MMBtu	4.7E-08	4.4E-05	0	0.000
bis(2-Ethylhexyl)phthalate (HAP)	X	AP-42	lb/MMBtu	4.7E-08	4.4E-05	0	0.000
Bromomethane		AP-42	lb/MMBtu	1.5E-05	1.4E-02	121	0.061
2-Butanone (MEK)		AP-42	lb/MMBtu	5.4E-06	5.0E-03	44	0.022
Carbazole	X	AP-42	lb/MMBtu	1.8E-06	1.7E-03	15	0.007
Carbon tetrachloride (HAP)	X	AP-42	lb/MMBtu	4.5E-05	4.2E-02	364	0.182
Chlorine (HAP)	X	AP-42	lb/MMBtu	7.9E-04	7.4E-01	6,397	3.198
Chlorobenzene (HAP)	X	AP-42	lb/MMBtu	3.3E-05	3.1E-02	267	0.134
Chloroform (HAP)	X	AP-42	lb/MMBtu	2.8E-05	2.6E-02	227	0.113
Chloromethane		AP-42	lb/MMBtu	2.3E-05	2.1E-02	186	0.093
2-Chloronaphthalene		AP-42	lb/MMBtu	2.4E-09	2.2E-06	0	0.000
2-Chlorophenol		AP-42	lb/MMBtu	2.4E-08	2.2E-05	0	0.000
Chrysene		AP-42	lb/MMBtu	3.8E-08	3.5E-05	0	0.000
Crotonaldehyde		AP-42	lb/MMBtu	9.9E-06	9.2E-03	80	0.040

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
Decachlorobiphenyl		AP-42	lb/MMBtu	2.7E-10	2.5E-07	0	0.000
Dibenzo(a,h)anthracene		AP-42	lb/MMBtu	9.1E-09	8.5E-06	0	0.000
1,2-Dibromoethene		AP-42	lb/MMBtu	5.5E-05	5.1E-02	445	0.223
Dichlorobiphenyl		AP-42	lb/MMBtu	7.4E-10	6.9E-07	0	0.000
1,2-Dichloroethane		AP-42	lb/MMBtu	2.9E-05	2.7E-02	235	0.117
Dichloromethane		AP-42	lb/MMBtu	2.9E-04	2.7E-01	2,348	1.174
1,2-Dichloropropane		AP-42	lb/MMBtu	3.3E-05	3.1E-02	267	0.134
2,4-Dinitrophenol		AP-42	lb/MMBtu	1.8E-07	1.7E-04	1	0.001
Ethylbenzene (HAP)	X	AP-42	lb/MMBtu	3.1E-05	2.9E-02	251	0.126
Fluoranthene		AP-42	lb/MMBtu	1.6E-06	1.5E-03	13	0.006
Fluorene		AP-42	lb/MMBtu	3.4E-06	3.2E-03	28	0.014
Formaldehyde (HAP)	X	AP-42	lb/MMBtu	4.4E-03	4.1E+00	35,628	17.814
Heptachlorobiphenyl		AP-42	lb/MMBtu	6.6E-11	6.2E-08	0	0.000
Hexachlorobiphenyl		AP-42	lb/MMBtu	5.5E-10	5.1E-07	0	0.000
Hexanal		AP-42	lb/MMBtu	7.0E-06	6.5E-03	57	0.028
Heptachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	2.0E-09	1.9E-06	0	0.000
Heptachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.4E-10	2.2E-07	0	0.000
Hexachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.6E-06	1.5E-03	13	0.006
Hexachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.8E-10	2.6E-07	0	0.000
Hydrogen Chloride (HAP)	X	NHDES Test Data	lb/MMBtu	8.3E-04	7.8E-01	6,753	3.377
Indeno(1,2,3,c,d)pyrene		AP-42	lb/MMBtu	8.7E-08	8.1E-05	1	0.000
Isobutyraldehyde		AP-42	lb/MMBtu	1.2E-05	1.1E-02	97	0.049
Methane		AP-42	lb/MMBtu	2.1E-02	2.0E+01	170,042	85.021
2-Methylnaphthalene		AP-42	lb/MMBtu	1.6E-07	1.5E-04	1	0.001
Monochlorobiphenyl		AP-42	lb/MMBtu	2.2E-10	2.1E-07	0	0.000
Naphthalene (HAP)	X	AP-42	lb/MMBtu	9.7E-05	9.0E-02	785	0.393
2-Nitrophenol		AP-42	lb/MMBtu	2.4E-07	2.2E-04	2	0.001
4-Nitrophenol (HAP)	X	AP-42	lb/MMBtu	1.1E-07	1.0E-04	1	0.000
Octachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	6.6E-08	6.2E-05	1	0.000
Octachlorodibenzo-p-furans		AP-42	lb/MMBtu	8.8E-11	8.2E-08	0	0.000
Pentachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.5E-09	1.4E-06	0	0.000
Pentachlorodibenzo-p-furans		AP-42	lb/MMBtu	4.2E-10	3.9E-07	0	0.000
Pentachlorobiphenyl		AP-42	lb/MMBtu	1.2E-09	1.1E-06	0	0.000
Pentachlorophenol (HAP)	X	AP-42	lb/MMBtu	5.1E-08	4.8E-05	0	0.000
Perylene		AP-42	lb/MMBtu	5.2E-10	4.8E-07	0	0.000
Phenanthrene		AP-42	lb/MMBtu	7.0E-06	6.5E-03	57	0.028
Phenol (HAP)	X	AP-42	lb/MMBtu	5.1E-05	4.8E-02	413	0.206
Propanal		AP-42	lb/MMBtu	3.2E-06	3.0E-03	26	0.013
Propionaldehyde (HAP)	X	AP-42	lb/MMBtu	6.1E-05	5.7E-02	494	0.247
Pyrene		AP-42	lb/MMBtu	3.7E-06	3.4E-03	30	0.015
Styrene (HAP)	X	AP-42	lb/MMBtu	1.9E-03	1.8E+00	15,385	7.692
2,3,7,8-Tetrachlorodibenzo-p-dioxins (HAP)	X	AP-42	lb/MMBtu	8.6E-12	8.0E-09	0	0.000
Tetrachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	4.7E-10	4.4E-07	0	0.000
2,3,7,8-Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	9.0E-11	8.4E-08	0	0.000
Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	7.5E-10	7.0E-07	0	0.000
Tetrachlorobiphenyl		AP-42	lb/MMBtu	2.5E-09	2.3E-06	0	0.000
Tetrachloroethene		AP-42	lb/MMBtu	3.8E-05	3.5E-02	308	0.154
o-Tolualdehyde		AP-42	lb/MMBtu	7.2E-06	6.7E-03	58	0.029
p-Tolualdehyde		AP-42	lb/MMBtu	1.1E-05	1.0E-02	89	0.045
Toluene (HAP)	X	AP-42	lb/MMBtu	9.2E-04	8.6E-01	7,449	3.725
Trichlorobiphenyl		AP-42	lb/MMBtu	2.6E-09	2.4E-06	0	0.000
1,1,1-Trichloroethane		AP-42	lb/MMBtu	3.1E-05	2.9E-02	251	0.126
Trichloroethene		AP-42	lb/MMBtu	3.0E-05	2.8E-02	243	0.121
Trichlorofluoromethane		AP-42	lb/MMBtu	4.1E-05	3.8E-02	332	0.166
2,4,6-Trichlorophenol (HAP)	X	AP-42	lb/MMBtu	2.2E-08	2.1E-05	0	0.000
Vinyl Chloride (HAP)	X	AP-42	lb/MMBtu	1.8E-05	1.7E-02	146	0.073
o-Xylene (HAP)	X	AP-42	lb/MMBtu	2.5E-05	2.3E-02	202	0.101
Total HAPS				0.016057433	1.5E+01	130,021	65.010
Largest Single HAP (Formaldehyde)						37,260	18.630

Potential Emissions Summary
Biomass Boiler - Phased Cold Startup
Berlin BioPower - Berlin, New Hampshire

Number of cold starts per year: 6

Phase 1 - #2 Fuel Oil Only (25% Load)

Biomass Boiler Startup	
Parameter	Fuel Oil
Duration of Start Up	8 hr
Heat Input Rate	240 MMBtu/hr
Fuel Firing Rate	1.714 kgal/hr

Pollutant	HAP	Emission Factor Source	#2 Fuel Oil Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
NOx		B&W	lb/MMBtu	0.20	48.00	384	0.19
CO		B&W	lb/MMBtu	0.50	120.00	960	0.48
SO2		B&W	lb/MMBtu	0.002	0.48	4	0.0019
PM (filterable)		B&W	lb/MMBtu	0.050	12.00	96	0.05
PM10 (filterable)		B&W	lb/MMBtu	0.050	12.00	96	0.05
PM2.5 (filterable)		B&W	lb/MMBtu	0.050	12.00	96	0.05
CO2		AP-42	lb/kgal	22,300	38,229	305,829	152.91
VOC		B&W	lb/MMBtu	0.015	3.60	29	0.014
Arsenic (HAP)	X	AP-42	lb/10^{12} Btu	4.00E+00	9.60E-04	8.E-03	3.84E-06
Beryllium (HAP)	X	AP-42	lb/10^{12} Btu	3.00E+00	7.20E-04	6.E-03	2.88E-06
Cadmium (HAP)	X	AP-42	lb/10^{12} Btu	3.00E+00	7.20E-04	6.E-03	2.88E-06
Chromium (HAP)	X	AP-42	lb/10^{12} Btu	3.00E+00	7.20E-04	6.E-03	2.88E-06
Copper		AP-42	lb/10^{12} Btu	6.00E+00	1.44E-03	1.E-02	5.76E-06
Lead (HAP)	X	AP-42	lb/10^{12} Btu	9.00E+00	2.16E-03	2.E-02	8.64E-06
Manganese (HAP)	X	AP-42	lb/10^{12} Btu	6.00E+00	1.44E-03	1.E-02	5.76E-06
Mercury (HAP)	X	AP-42	lb/10^{12} Btu	3.00E+00	7.20E-04	6.E-03	2.88E-06
Nickel (HAP)	X	AP-42	lb/10^{12} Btu	3.00E+00	7.20E-04	6.E-03	2.88E-06
Selenium (HAP)	X	AP-42	lb/10^{12} Btu	1.50E+01	3.60E-03	3.E-02	1.44E-05
Zinc		AP-42	lb/10^{12} Btu	4.00E+00	9.60E-04	8.E-03	3.84E-06
Acenaphthene		AP-42	lb/kgal	2.11E-05	3.62E-05	3.E-04	1.45E-07
Acenaphthylene		AP-42	lb/kgal	2.53E-07	4.34E-07	3.E-06	1.73E-09
Anthracene		AP-42	lb/kgal	1.22E-06	2.09E-06	2.E-05	8.37E-09
Benz(a)anthracene		AP-42	lb/kgal	4.01E-06	6.87E-06	5.E-05	2.75E-08
Benzene (HAP)	X	AP-42	lb/kgal	2.14E-04	3.67E-04	3.E-03	1.47E-06
Benzo(b,k)fluoranthene		AP-42	lb/kgal	1.48E-06	2.54E-06	2.E-05	1.01E-08
Benzo(g,h,i)perylene		AP-42	lb/kgal	2.26E-06	3.87E-06	3.E-05	1.55E-08
Chrysene		AP-42	lb/kgal	2.38E-06	4.08E-06	3.E-05	1.63E-08
Dibenzo(a,h)anthracene		AP-42	lb/kgal	1.67E-06	2.86E-06	2.E-05	1.15E-08
Ethylbenzene (HAP)	X	AP-42	lb/kgal	6.36E-05	1.09E-04	9.E-04	4.36E-07
Fluoranthene		AP-42	lb/kgal	4.84E-06	8.30E-06	7.E-05	3.32E-08
Fluorene		AP-42	lb/kgal	4.47E-06	7.66E-06	6.E-05	3.07E-08
Formaldehyde (HAP)	X	AP-42	lb/kgal	6.10E-02	1.05E-01	8.E-01	4.18E-04
Indeno(1,2,3-cd)pyrene		AP-42	lb/kgal	2.14E-06	3.67E-06	3.E-05	1.47E-08
Naphthalene (HAP)	X	AP-42	lb/kgal	1.13E-03	1.94E-03	2.E-02	7.75E-06
Phenanthrene		AP-42	lb/kgal	1.05E-05	1.80E-05	1.E-04	7.20E-08
Pyrene		AP-42	lb/kgal	4.25E-06	7.29E-06	6.E-05	2.91E-08
1,1,1-Trichloroethane (HAP)	X	AP-42	lb/kgal	2.36E-04	4.05E-04	3.E-03	1.62E-06
Toluene (HAP)	X	AP-42	lb/kgal	6.20E-03	1.06E-02	9.E-02	4.25E-05
o-Xylene (HAP)	X	AP-42	lb/kgal	1.09E-04	1.87E-04	1.E-03	7.47E-07
OCDD (HAP)	X	AP-42	lb/kgal	3.10E-09	5.31E-09	4.E-08	2.13E-11
Total HAPS					**1.30E-01**	**1.04E+00**	**5.20E-04**

Potential Emissions Summary
Biomass Boiler - Phased Cold Startup
Berlin BioPower - Berlin, New Hampshire

Number of cold starts per year: 6

Phase 2 - #2 Fuel Oil & Biomass (25-50% Load)

Parameter	Fuel Oil
Duration of Start Up	3 hr
Heat Input Rate	120.0 MMBtu/hr
Fuel Firing Rate	0.857 kgal/hr

Pollutant	HAP	Emission Factor Source	#2 Fuel Oil: Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
NOx		B&W	lb/MMBtu	0.20	24.00	72	0.036
CO		B&W	lb/MMBtu	0.50	60.00	180	0.090
SO2		B&W	lb/MMBtu	0.002	0.24	1	0.00036
PM (filterable)		B&W	lb/MMBtu	0.050	6.00	18	0.009
PM (filterable)		B&W	lb/MMBtu	0.050	6.00	18	0.009
PM10 (filterable)		B&W	lb/MMBtu	0.050	6.00	18	0.009
PM2.5 (filterable)		B&W	lb/MMBtu	0.050	6.00	18	0.009
CO2		AP-42	lb/kgal	22,300	19,114	57,343	28.67
VOC		B&W	lb/MMBtu	0.015	1.80	5	0.0027
Arsenic (HAP)	X	AP-42	lb/10^{12} Btu	4.0E+00	4.8E-04	1.4E-03	7.2E-07
Beryllium (HAP)	X	AP-42	lb/10^{12} Btu	3.0E+00	3.6E-04	1.1E-03	5.4E-07
Cadmium (HAP)	X	AP-42	lb/10^{12} Btu	3.0E+00	3.6E-04	1.1E-03	5.4E-07
Chromium (HAP)	X	AP-42	lb/10^{12} Btu	3.0E+00	3.6E-04	1.1E-03	5.4E-07
Copper		AP-42	lb/10^{12} Btu	6.0E+00	7.2E-04	2.2E-03	1.1E-06
Lead (HAP)	X	AP-42	lb/10^{12} Btu	9.0E+00	1.1E-03	3.2E-03	1.6E-06
Manganese (HAP)	X	AP-42	lb/10^{12} Btu	6.0E+00	7.2E-04	2.2E-03	1.1E-06
Mercury (HAP)	X	AP-42	lb/10^{12} Btu	3.0E+00	3.6E-04	1.1E-03	5.4E-07
Nickel (HAP)	X	AP-42	lb/10^{12} Btu	3.0E+00	3.6E-04	1.1E-03	5.4E-07
Selenium (HAP)	X	AP-42	lb/10^{12} Btu	1.5E+01	1.8E-03	5.4E-03	2.7E-06
Zinc		AP-42	lb/10^{12} Btu	4.0E+00	4.8E-04	1.4E-03	7.2E-07
Acenaphthene		AP-42	lb/kgal	2.1E-05	1.8E-05	5.4E-05	2.7E-08
Acenaphthylene		AP-42	lb/kgal	2.5E-07	2.2E-07	6.5E-07	3.3E-10
Anthracene		AP-42	lb/kgal	1.2E-06	1.0E-06	3.1E-06	1.6E-09
Benz(a)anthracene		AP-42	lb/kgal	4.0E-06	3.4E-06	1.0E-05	5.2E-09
Benzene (HAP)	X	AP-42	lb/kgal	2.1E-04	1.8E-04	5.5E-04	2.8E-07
Benzo(b,k)fluoranthene		AP-42	lb/kgal	1.5E-06	1.3E-06	3.8E-06	1.9E-09
Benzo(g,h,i)perylene		AP-42	lb/kgal	2.3E-06	1.9E-06	5.8E-06	2.9E-09
Chrysene		AP-42	lb/kgal	2.4E-06	2.0E-06	6.1E-06	3.1E-09
Dibenzo(a,h)anthracene		AP-42	lb/kgal	1.7E-06	1.4E-06	4.3E-06	2.1E-09
Ethylbenzene (HAP)	X	AP-42	lb/kgal	6.4E-05	5.5E-05	1.6E-04	8.2E-08
Fluoranthene		AP-42	lb/kgal	4.8E-06	4.1E-06	1.2E-05	6.2E-09
Fluorene		AP-42	lb/kgal	4.5E-06	3.8E-06	1.1E-05	5.7E-09
Formaldehyde (HAP)	X	AP-42	lb/kgal	6.1E-02	5.2E-02	1.6E-01	7.8E-05
Indeno(1,2,3-cd)pyrene		AP-42	lb/kgal	2.1E-06	1.8E-06	5.5E-06	2.8E-09
Naphthalene (HAP)	X	AP-42	lb/kgal	1.1E-03	9.7E-04	2.9E-03	1.5E-06
Phenanthrene		AP-42	lb/kgal	1.1E-05	9.0E-06	2.7E-05	1.4E-08
Pyrene		AP-42	lb/kgal	4.3E-06	3.6E-06	1.1E-05	5.5E-09
1,1,1-Trichloroethane (HAP)	X	AP-42	lb/kgal	2.4E-04	2.0E-04	6.1E-04	3.0E-07
Toluene (HAP)	X	AP-42	lb/kgal	6.2E-03	5.3E-03	1.6E-02	8.0E-06
o-Xylene (HAP)	X	AP-42	lb/kgal	1.1E-04	9.3E-05	2.8E-04	1.4E-07
OCDD (HAP)	X	AP-42	lb/kgal	3.1E-09	2.7E-09	8.0E-09	4.0E-12
Total HAPS					**6.5E-02**	**1.9E-01**	**9.7E-05**

Total Emissions for Start up

Pollutant	Emissions Per Start up: Emission Rate lb/start up	Emission Rate ton/start up	Start up emissions Per Year: Emission Rate lb/year	Emission Rate ton/year
NOx	531	0.266	3,189	1.59
CO	1,234	0.617	7,406	3.70
SO2	20	0.010	118	0.06
PM (filterable)	127	0.063	759	0.38
PM10 (filterable)	127	0.063	759	0.38
PM2.5 (filterable)	127	0.063	759	0.38
CO2	641,234	320.617	3,847,402	1923.70
VOC	48.2	0.024	289	0.14
Total HAPS	21	0.011	129	0.06

Biomass Boiler Startup

Parameter	Wood Fuel
Duration of Start Up	3 hr
Heat Input Rate	233.0 MMBtu/hr
Fuel Firing Rate	23.0 ton/hr

Wood Fuel

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
NOx		B&W	lb/MMBtu	0.060	14.0	42	0.021
CO		B&W	lb/MMBtu	0.075	17.5	52	0.026
SO2		B&W	lb/MMBtu	0.012	2.8	8	0.004
H2SO4 (assumes 10% SO2:SO3 Conv)		Assumed	lb/MMBtu	0.002	0.4	1	0.0006
PM (filterable)		B&W	lb/MMBtu	0.010	2.3	7	0.0035
PM10 (filterable)		B&W	lb/MMBtu	0.010	2.3	7	0.0035
PM2.5 (filterable)		B&W	lb/MMBtu	0.010	2.3	7	0.0035
CO2		B&W	lb/MMBtu	221.0	51,493.0	154,479	77.240
NH3 (Assumes 20 ppm slip)		Assumed	lb/MMBtu	0.012	2.8	8	0.0042
VOC		B&W	lb/MMBtu	0.010	2.3	7	0.0035
Antimony (HAP)	X	AP-42	lb/MMBtu	7.9E-06	1.8E-03	5.5E-03	2.8E-06
Arsenic (HAP)	X	AP-42	lb/MMBtu	2.2E-05	5.1E-03	1.5E-02	7.7E-06
Barium		AP-42	lb/MMBtu	1.7E-04	4.0E-02	1.2E-01	5.9E-05
Beryllium (HAP)	X	AP-42	lb/MMBtu	1.1E-06	2.6E-04	7.7E-04	3.8E-07
Cadmium (HAP)	X	AP-42	lb/MMBtu	4.1E-06	9.6E-04	2.9E-03	1.4E-06
Chromium, Total (HAP)	X	AP-42	lb/MMBtu	2.1E-05	4.9E-03	1.5E-02	7.3E-06
Cobalt (HAP)	X	AP-42	lb/MMBtu	6.5E-06	1.5E-03	4.5E-03	2.3E-06
Copper		AP-42	lb/MMBtu	4.9E-05	1.1E-02	3.4E-02	1.7E-05
Iron		AP-42	lb/MMBtu	9.9E-04	2.3E-01	6.9E-01	3.5E-04
Lead (HAP)	X	AP-42	lb/MMBtu	4.8E-05	1.1E-02	3.4E-02	1.7E-05
Manganese (HAP)	X	AP-42	lb/MMBtu	1.6E-03	3.7E-01	1.1E+00	5.6E-04
Mercury (HAP)	X	MACT	lb/MMBtu	3.0E-06	7.0E-04	2.1E-03	1.0E-06
Molybdenum		AP-42	lb/MMBtu	2.1E-06	4.9E-04	1.5E-03	7.3E-07
Nickel (HAP)	X	AP-42	lb/MMBtu	3.3E-05	7.7E-03	2.3E-02	1.2E-05
Phosphorous		AP-42	lb/MMBtu	2.7E-05	6.3E-03	1.9E-02	9.4E-06
Potassium		AP-42	lb/MMBtu	3.9E-02	9.1E+00	2.7E+01	1.4E-02
Selenium (HAP)	X	AP-42	lb/MMBtu	2.8E-06	6.5E-04	2.0E-03	9.8E-07
Silver		AP-42	lb/MMBtu	1.7E-03	4.0E-01	1.2E+00	5.9E-04
Sodium		AP-42	lb/MMBtu	3.6E-04	8.4E-02	2.5E-01	1.3E-04
Strontium		AP-42	lb/MMBtu	1.0E-05	2.3E-03	7.0E-03	3.5E-06
Tin		AP-42	lb/MMBtu	2.3E-05	5.4E-03	1.6E-02	8.0E-06
Titanium		AP-42	lb/MMBtu	2.0E-05	4.7E-03	1.4E-02	7.0E-06
Vanadium		AP-42	lb/MMBtu	9.8E-07	2.3E-04	6.9E-04	3.4E-07
Yttrium		AP-42	lb/MMBtu	3.0E-07	7.0E-05	2.1E-04	1.0E-07
Zinc		AP-42	lb/MMBtu	4.2E-04	9.8E-02	2.9E-01	1.5E-04
						0.0E+00	
Acenaphthene		AP-42	lb/MMBtu	9.1E-07	2.1E-04	6.4E-04	3.2E-07
Acenaphthylene		AP-42	lb/MMBtu	5.0E-06	1.2E-03	3.5E-03	1.7E-06
Acetaldehyde (HAP)	X	AP-42	lb/MMBtu	8.3E-04	1.9E-01	5.8E-01	2.9E-04
Acetone		AP-42	lb/MMBtu	1.9E-04	4.4E-02	1.3E-01	6.6E-05
Acetophenone (HAP)	X	AP-42	lb/MMBtu	3.2E-09	7.5E-07	2.2E-06	1.1E-09
Acrolein (HAP)	X	Bridgewater	lb/MMBtu	4.3E-05	1.0E-02	3.0E-02	1.5E-05
Anthracene		AP-42	lb/MMBtu	3.0E-06	7.0E-04	2.1E-03	1.0E-06
Benzaldehyde		AP-42	lb/MMBtu	8.5E-07	2.0E-04	5.9E-04	3.0E-07
Benzene (HAP)	X	AP-42	lb/MMBtu	4.2E-03	9.8E-01	2.9E+00	1.5E-03
Benzo(a)anthracene		AP-42	lb/MMBtu	6.5E-08	1.5E-05	4.5E-05	2.3E-08
Benzo(a)pyrene		AP-42	lb/MMBtu	2.6E-06	6.1E-04	1.8E-03	9.1E-07
Benzo(b)fluoranthene		AP-42	lb/MMBtu	1.0E-07	2.3E-05	7.0E-05	3.5E-08
Benzo(e)pyrene		AP-42	lb/MMBtu	2.6E-09	6.1E-07	1.8E-06	9.1E-10
Benzo(g,h,l)perylene		AP-42	lb/MMBtu	9.3E-08	2.2E-05	6.5E-05	3.3E-08
Benzo(j,k)fluoranthene		AP-42	lb/MMBtu	1.6E-07	3.7E-05	1.1E-04	5.6E-08
Benzo(k)fluoranthene		AP-42	lb/MMBtu	3.6E-08	8.4E-06	2.5E-05	1.3E-08
Benzoic acid		AP-42	lb/MMBtu	4.7E-08	1.1E-05	3.3E-05	1.6E-08
bis(2-Ethylhexyl)phthalate (HAP)	X	AP-42	lb/MMBtu	4.7E-08	1.1E-05	3.3E-05	1.6E-08
Bromomethane		AP-42	lb/MMBtu	1.5E-05	3.5E-03	1.0E-02	5.2E-06
2-Butanone (MEK)		AP-42	lb/MMBtu	5.4E-06	1.3E-03	3.8E-03	1.9E-06
Carbazole	X	AP-42	lb/MMBtu	1.8E-06	4.2E-04	1.3E-03	6.3E-07
Carbon tetrachloride (HAP)	X	AP-42	lb/MMBtu	4.5E-05	1.0E-02	3.1E-02	1.6E-05
Chlorine (HAP)	X	AP-42	lb/MMBtu	7.9E-04	1.8E-01	5.5E-01	2.8E-04
Chlorobenzene (HAP)	X	AP-42	lb/MMBtu	3.3E-05	7.7E-03	2.3E-02	1.2E-05
Chloroform (HAP)	X	AP-42	lb/MMBtu	2.8E-05	6.5E-03	2.0E-02	9.8E-06
Chloromethane		AP-42	lb/MMBtu	2.3E-05	5.4E-03	1.6E-02	8.0E-06
2-Chloronaphthalene		AP-42	lb/MMBtu	2.4E-09	5.6E-07	1.7E-06	8.4E-10
2-Chlorophenol		AP-42	lb/MMBtu	2.4E-08	5.6E-06	1.7E-05	8.4E-09
Chrysene		AP-42	lb/MMBtu	3.8E-08	8.9E-06	2.7E-05	1.3E-08
Crotonaldehyde		AP-42	lb/MMBtu	9.9E-06	2.3E-03	6.9E-03	3.5E-06

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
Decachlorobiphenyl		AP-42	lb/MMBtu	2.7E-10	6.3E-08	1.9E-07	9.4E-11
Dibenzo(a,h)anthracene		AP-42	lb/MMBtu	9.1E-09	2.1E-06	6.4E-06	3.2E-09
1,2-Dibromoethene		AP-42	lb/MMBtu	5.5E-05	1.3E-02	3.8E-02	1.9E-05
Dichlorobiphenyl		AP-42	lb/MMBtu	7.4E-10	1.7E-07	5.2E-07	2.6E-10
1,2-Dichloroethane		AP-42	lb/MMBtu	2.9E-05	6.8E-03	2.0E-02	1.0E-05
Dichloromethane		AP-42	lb/MMBtu	2.9E-04	6.8E-02	2.0E-01	1.0E-04
1,2-Dichloropropane		AP-42	lb/MMBtu	3.3E-05	7.7E-03	2.3E-02	1.2E-05
2,4-Dinitrophenol		AP-42	lb/MMBtu	1.8E-07	4.2E-05	1.3E-04	6.3E-08
Ethylbenzene (HAP)	X	AP-42	lb/MMBtu	3.1E-05	7.2E-03	2.2E-02	1.1E-05
Fluoranthene		AP-42	lb/MMBtu	1.6E-06	3.7E-04	1.1E-03	5.6E-07
Fluorene		AP-42	lb/MMBtu	3.4E-06	7.9E-04	2.4E-03	1.2E-06
Formaldehyde (HAP)	X	AP-42	lb/MMBtu	4.4E-03	1.0E+00	3.1E+00	1.5E-03
Heptachlorobiphenyl		AP-42	lb/MMBtu	6.6E-11	1.5E-08	4.6E-08	2.3E-11
Hexachlorobiphenyl		AP-42	lb/MMBtu	5.5E-10	1.3E-07	3.8E-07	1.9E-10
Hexanal		AP-42	lb/MMBtu	7.0E-06	1.6E-03	4.9E-03	2.4E-06
Heptachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	2.0E-09	4.7E-07	1.4E-06	7.0E-10
Heptachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.4E-10	5.6E-08	1.7E-07	8.4E-11
Hexachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.6E-06	3.7E-04	1.1E-03	5.6E-07
Hexachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.8E-10	6.5E-08	2.0E-07	9.8E-11
Hydrogen Chloride (HAP)	X	HDES Test Da	lb/MMBtu	8.3E-04	1.9E-01	5.8E-01	2.9E-04
Indeno(1,2,3,c,d)pyrene		AP-42	lb/MMBtu	8.7E-08	2.0E-05	6.1E-05	3.0E-08
Isobutyraldehyde		AP-42	lb/MMBtu	1.2E-05	2.8E-03	8.4E-03	4.2E-06
Methane		AP-42	lb/MMBtu	2.1E-02	4.9E+00	1.5E+01	7.3E-03
2-Methylnaphthalene		AP-42	lb/MMBtu	1.6E-07	3.7E-05	1.1E-04	5.6E-08
Monochlorobiphenyl		AP-42	lb/MMBtu	2.2E-10	5.1E-08	1.5E-07	7.7E-11
Naphthalene (HAP)	X	AP-42	lb/MMBtu	9.7E-05	2.3E-02	6.8E-02	3.4E-05
2-Nitrophenol		AP-42	lb/MMBtu	2.4E-07	5.6E-05	1.7E-04	8.4E-08
4-Nitrophenol (HAP)	X	AP-42	lb/MMBtu	1.1E-07	2.6E-05	7.7E-05	3.8E-08
Octachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	6.6E-08	1.5E-05	4.6E-05	2.3E-08
Octachlorodibenzo-p-furans		AP-42	lb/MMBtu	8.8E-11	2.1E-08	6.2E-08	3.1E-11
Pentachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.5E-09	3.5E-07	1.0E-06	5.2E-10
Pentachlorodibenzo-p-furans		AP-42	lb/MMBtu	4.2E-10	9.8E-08	2.9E-07	1.5E-10
Pentachlorobiphenyl		AP-42	lb/MMBtu	1.2E-09	2.8E-07	8.4E-07	4.2E-10
Pentachlorophenol (HAP)	X	AP-42	lb/MMBtu	5.1E-08	1.2E-05	3.6E-05	1.8E-08
Perylene		AP-42	lb/MMBtu	5.2E-10	1.2E-07	3.6E-07	1.8E-10
Phenanthrene		AP-42	lb/MMBtu	7.0E-06	1.6E-03	4.9E-03	2.4E-06
Phenol (HAP)	X	AP-42	lb/MMBtu	5.1E-05	1.2E-02	3.6E-02	1.8E-05
Propanal		AP-42	lb/MMBtu	3.2E-06	7.5E-04	2.2E-03	1.1E-06
Propionaldehyde (HAP)	X	AP-42	lb/MMBtu	6.1E-05	1.4E-02	4.3E-02	2.1E-05
Pyrene		AP-42	lb/MMBtu	3.7E-06	8.6E-04	2.6E-03	1.3E-06
Styrene (HAP)	X	AP-42	lb/MMBtu	1.9E-03	4.4E-01	1.3E+00	6.6E-04
2,3,7,8-Tetrachlorodibenzo-p-dio	X	AP-42	lb/MMBtu	8.6E-12	2.0E-09	6.0E-09	3.0E-12
Tetrachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	4.7E-10	1.1E-07	3.3E-07	1.6E-10
2,3,7,8-Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	9.0E-11	2.1E-08	6.3E-08	3.1E-11
Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	7.5E-10	1.7E-07	5.2E-07	2.6E-10
Tetrachlorobiphenyl		AP-42	lb/MMBtu	2.5E-09	5.8E-07	1.7E-06	8.7E-10
Tetrachloroethene		AP-42	lb/MMBtu	3.8E-05	8.9E-03	2.7E-02	1.3E-05
o-Tolualdehyde		AP-42	lb/MMBtu	7.2E-06	1.7E-03	5.0E-03	2.5E-06
p-Tolualdehyde		AP-42	lb/MMBtu	1.1E-05	2.6E-03	7.7E-03	3.8E-06
Toluene (HAP)	X	AP-42	lb/MMBtu	9.2E-04	2.1E-01	6.4E-01	3.2E-04
Trichlorobiphenyl		AP-42	lb/MMBtu	2.6E-09	6.1E-07	1.8E-06	9.1E-10
1,1,1-Trichloroethane		AP-42	lb/MMBtu	3.1E-05	7.2E-03	2.2E-02	1.1E-05
Trichloroethene		AP-42	lb/MMBtu	3.0E-05	7.0E-03	2.1E-02	1.0E-05
Trichlorofluoromethane		AP-42	lb/MMBtu	4.1E-05	9.6E-03	2.9E-02	1.4E-05
2,4,6-Trichlorophenol (HAP)	X	AP-42	lb/MMBtu	2.2E-08	5.1E-06	1.5E-05	7.7E-09
Vinyl Chloride (HAP)	X	AP-42	lb/MMBtu	1.8E-05	4.2E-03	1.3E-02	6.3E-06
o-Xylene (HAP)	X	AP-42	lb/MMBtu	2.5E-05	5.8E-03	1.7E-02	8.7E-06
Total HAPS				1.6E-02	3.7E+00	1.1E+01	5.6E-03
Largest Single HAP (Formaldehyde)						3.1E+00	1.5E-03

Potential Emissions Summary
Biomass Boiler - Phased Cold Startup
Berlin BioPower - Berlin, New Hampshire

Number of cold starts per year: 6

Phase 3 - Biomass Only (50-70% Load)

Parameter	Wood Fuel
Duration of Start Up	1 hr
Heat Input Rate	559.2 MMBtu/hr
Fuel Firing Rate	55.2 ton/hr

Wood Fuel

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
NOx		B&W	lb/MMBtu	0.060	33.6	34	0.017
CO		B&W	lb/MMBtu	0.075	41.9	42	0.021
SO2		B&W	lb/MMBtu	0.012	6.7	7	0.003
H2SO4 (assumes 10% SO2:SO3 Conv)		Assumed	lb/MMBtu	0.002	1.0	1	0.0005
PM (filterable)		B&W	lb/MMBtu	0.010	5.6	6	0.0028
PM10 (filterable)		B&W	lb/MMBtu	0.010	5.6	6	0.0028
PM2.5 (filterable)		B&W	lb/MMBtu	0.010	5.6	6	0.0028
CO2		B&W	lb/MMBtu	221.0	123,583.2	123,583	61.792
NH3 (Assumes 20 ppm slip)		Assumed	lb/MMBtu	0.012	6.7	7	0.0034
VOC		B&W	lb/MMBtu	0.010	5.6	6	0.0028
Antimony (HAP)	X	AP-42	lb/MMBtu	7.9E-06	4.4E-03	4.4E-03	2.2E-06
Arsenic (HAP)	X	AP-42	lb/MMBtu	2.2E-05	1.2E-02	1.2E-02	6.2E-06
Barium		AP-42	lb/MMBtu	1.7E-04	9.5E-02	9.5E-02	4.8E-05
Beryllium (HAP)	X	AP-42	lb/MMBtu	1.1E-06	6.2E-04	6.2E-04	3.1E-07
Cadmium (HAP)	X	AP-42	lb/MMBtu	4.1E-06	2.3E-03	2.3E-03	1.1E-06
Chromium, Total (HAP)	X	AP-42	lb/MMBtu	2.1E-05	1.2E-02	1.2E-02	5.9E-06
Cobalt (HAP)	X	AP-42	lb/MMBtu	6.5E-06	3.6E-03	3.6E-03	1.8E-06
Copper		AP-42	lb/MMBtu	4.9E-05	2.7E-02	2.7E-02	1.4E-05
Iron		AP-42	lb/MMBtu	9.9E-04	5.5E-01	5.5E-01	2.8E-04
Lead (HAP)	X	AP-42	lb/MMBtu	4.8E-05	2.7E-02	2.7E-02	1.3E-05
Manganese (HAP)	X	AP-42	lb/MMBtu	1.6E-03	8.9E-01	8.9E-01	4.5E-04
Mercury (HAP)	X	MACT	lb/MMBtu	3.0E-06	1.7E-03	1.7E-03	8.4E-07
Molybdenum		AP-42	lb/MMBtu	2.1E-06	1.2E-03	1.2E-03	5.9E-07
Nickel (HAP)	X	AP-42	lb/MMBtu	3.3E-05	1.8E-02	1.8E-02	9.2E-06
Phosphorous		AP-42	lb/MMBtu	2.7E-05	1.5E-02	1.5E-02	7.5E-06
Potassium		AP-42	lb/MMBtu	3.9E-02	2.2E+01	2.2E+01	1.1E-02
Selenium (HAP)	X	AP-42	lb/MMBtu	2.8E-06	1.6E-03	1.6E-03	7.8E-07
Silver		AP-42	lb/MMBtu	1.7E-03	9.5E-01	9.5E-01	4.8E-04
Sodium		AP-42	lb/MMBtu	3.6E-04	2.0E-01	2.0E-01	1.0E-04
Strontium		AP-42	lb/MMBtu	1.0E-05	5.6E-03	5.6E-03	2.8E-06
Tin		AP-42	lb/MMBtu	2.3E-05	1.3E-02	1.3E-02	6.4E-06
Titanium		AP-42	lb/MMBtu	2.0E-05	1.1E-02	1.1E-02	5.6E-06
Vanadium		AP-42	lb/MMBtu	9.8E-07	5.5E-04	5.5E-04	2.7E-07
Yttrium		AP-42	lb/MMBtu	3.0E-07	1.7E-04	1.7E-04	8.4E-08
Zinc		AP-42	lb/MMBtu	4.2E-04	2.3E-01	2.3E-01	1.2E-04
Acenaphthene		AP-42	lb/MMBtu	9.1E-07	5.1E-04	5.1E-04	2.5E-07
Acenaphthylene		AP-42	lb/MMBtu	5.0E-06	2.8E-03	2.8E-03	1.4E-06
Acetaldehyde (HAP)	X	AP-42	lb/MMBtu	8.3E-04	4.6E-01	4.6E-01	2.3E-04
Acetone		AP-42	lb/MMBtu	1.9E-04	1.1E-01	1.1E-01	5.3E-05
Acetophenone (HAP)	X	AP-42	lb/MMBtu	3.2E-09	1.8E-06	1.8E-06	8.9E-10
Acrolein (HAP)	X	Bridgewater	lb/MMBtu	4.3E-05	2.4E-02	2.4E-02	1.2E-05
Anthracene		AP-42	lb/MMBtu	3.0E-06	1.7E-03	1.7E-03	8.4E-07
Benzaldehyde		AP-42	lb/MMBtu	8.5E-07	4.8E-04	4.8E-04	2.4E-07
Benzene (HAP)	X	AP-42	lb/MMBtu	4.2E-03	2.3E+00	2.3E+00	1.2E-03
Benzo(a)anthracene		AP-42	lb/MMBtu	6.5E-08	3.6E-05	3.6E-05	1.8E-08
Benzo(a)pyrene		AP-42	lb/MMBtu	2.6E-06	1.5E-03	1.5E-03	7.3E-07
Benzo(b)fluoranthene		AP-42	lb/MMBtu	1.0E-07	5.6E-05	5.6E-05	2.8E-08
Benzo(e)pyrene		AP-42	lb/MMBtu	2.6E-09	1.5E-06	1.5E-06	7.3E-10
Benzo(g,h,i)perylene		AP-42	lb/MMBtu	9.3E-08	5.2E-05	5.2E-05	2.6E-08
Benzo(j,k)fluoranthene		AP-42	lb/MMBtu	1.6E-07	8.9E-05	8.9E-05	4.5E-08
Benzo(k)fluoranthene		AP-42	lb/MMBtu	3.6E-08	2.0E-05	2.0E-05	1.0E-08
Benzoic acid		AP-42	lb/MMBtu	4.7E-08	2.6E-05	2.6E-05	1.3E-08
bis(2-Ethylhexyl)phthalate (HAP)	X	AP-42	lb/MMBtu	4.7E-08	2.6E-05	2.6E-05	1.3E-08
Bromomethane		AP-42	lb/MMBtu	1.5E-05	8.4E-03	8.4E-03	4.2E-06
2-Butanone (MEK)		AP-42	lb/MMBtu	5.4E-06	3.0E-03	3.0E-03	1.5E-06
Carbazole	X	AP-42	lb/MMBtu	1.8E-06	1.0E-03	1.0E-03	5.0E-07
Carbon tetrachloride (HAP)	X	AP-42	lb/MMBtu	4.5E-05	2.5E-02	2.5E-02	1.3E-05
Chlorine (HAP)	X	AP-42	lb/MMBtu	7.9E-04	4.4E-01	4.4E-01	2.2E-04
Chlorobenzene (HAP)	X	AP-42	lb/MMBtu	3.3E-05	1.8E-02	1.8E-02	9.2E-06
Chloroform (HAP)	X	AP-42	lb/MMBtu	2.8E-05	1.6E-02	1.6E-02	7.8E-06
Chloromethane		AP-42	lb/MMBtu	2.3E-05	1.3E-02	1.3E-02	6.4E-06
2-Chloronaphthalene		AP-42	lb/MMBtu	2.4E-09	1.3E-06	1.3E-06	6.7E-10
2-Chlorophenol		AP-42	lb/MMBtu	2.4E-08	1.3E-05	1.3E-05	6.7E-09
Chrysene		AP-42	lb/MMBtu	3.8E-08	2.1E-05	2.1E-05	1.1E-08
Crotonaldehyde		AP-42	lb/MMBtu	9.9E-06	5.5E-03	5.5E-03	2.8E-06

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/start up	Emission Rate ton/start up
Decachlorobiphenyl		AP-42	lb/MMBtu	2.7E-10	1.5E-07	1.5E-07	7.5E-11
Dibenzo(a,h)anthracene		AP-42	lb/MMBtu	9.1E-09	5.1E-06	5.1E-06	2.5E-09
1,2-Dibromoethene		AP-42	lb/MMBtu	5.5E-05	3.1E-02	3.1E-02	1.5E-05
Dichlorobiphenyl		AP-42	lb/MMBtu	7.4E-10	4.1E-07	4.1E-07	2.1E-10
1,2-Dichloroethane		AP-42	lb/MMBtu	2.9E-05	1.6E-02	1.6E-02	8.1E-06
Dichloromethane		AP-42	lb/MMBtu	2.9E-04	1.6E-01	1.6E-01	8.1E-05
1,2-Dichloropropane		AP-42	lb/MMBtu	3.3E-05	1.8E-02	1.8E-02	9.2E-06
2,4-Dinitrophenol		AP-42	lb/MMBtu	1.8E-07	1.0E-04	1.0E-04	5.0E-08
Ethylbenzene (HAP)	X	AP-42	lb/MMBtu	3.1E-05	1.7E-02	1.7E-02	8.7E-06
Fluoranthene		AP-42	lb/MMBtu	1.6E-06	8.9E-04	8.9E-04	4.5E-07
Fluorene		AP-42	lb/MMBtu	3.4E-06	1.9E-03	1.9E-03	9.5E-07
Formaldehyde (HAP)	X	AP-42	lb/MMBtu	4.4E-03	2.5E+00	2.5E+00	1.2E-03
Heptachlorobiphenyl		AP-42	lb/MMBtu	6.6E-11	3.7E-08	3.7E-08	1.8E-11
Hexachlorobiphenyl		AP-42	lb/MMBtu	5.5E-10	3.1E-07	3.1E-07	1.5E-10
Hexanal		AP-42	lb/MMBtu	7.0E-06	3.9E-03	3.9E-03	2.0E-06
Heptachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	2.0E-09	1.1E-06	1.1E-06	5.6E-10
Heptachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.4E-10	1.3E-07	1.3E-07	6.7E-11
Hexachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.6E-06	8.9E-04	8.9E-04	4.5E-07
Hexachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.8E-10	1.6E-07	1.6E-07	7.8E-11
Hydrogen Chloride (HAP)	X	DES Test Da	lb/MMBtu	8.3E-04	4.7E-01	4.7E-01	2.3E-04
Indeno(1,2,3,c,d)pyrene		AP-42	lb/MMBtu	8.7E-08	4.9E-05	4.9E-05	2.4E-08
Isobutyraldehyde		AP-42	lb/MMBtu	1.2E-05	6.7E-03	6.7E-03	3.4E-06
Methane		AP-42	lb/MMBtu	2.1E-02	1.2E+01	1.2E+01	5.9E-03
2-Methylnaphthalene		AP-42	lb/MMBtu	1.6E-07	8.9E-05	8.9E-05	4.5E-08
Monochlorobiphenyl		AP-42	lb/MMBtu	2.2E-10	1.2E-07	1.2E-07	6.2E-11
Naphthalene (HAP)	X	AP-42	lb/MMBtu	9.7E-05	5.4E-02	5.4E-02	2.7E-05
2-Nitrophenol		AP-42	lb/MMBtu	2.4E-07	1.3E-04	1.3E-04	6.7E-08
4-Nitrophenol (HAP)	X	AP-42	lb/MMBtu	1.1E-07	6.2E-05	6.2E-05	3.1E-08
Octachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	6.6E-08	3.7E-05	3.7E-05	1.8E-08
Octachlorodibenzo-p-furans		AP-42	lb/MMBtu	8.8E-11	4.9E-08	4.9E-08	2.5E-11
Pentachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.5E-09	8.4E-07	8.4E-07	4.2E-10
Pentachlorodibenzo-p-furans		AP-42	lb/MMBtu	4.2E-10	2.3E-07	2.3E-07	1.2E-10
Pentachlorobiphenyl		AP-42	lb/MMBtu	1.2E-09	6.7E-07	6.7E-07	3.4E-10
Pentachlorophenol (HAP)	X	AP-42	lb/MMBtu	5.1E-08	2.9E-05	2.9E-05	1.4E-08
Perylene		AP-42	lb/MMBtu	5.2E-10	2.9E-07	2.9E-07	1.5E-10
Phenanthrene		AP-42	lb/MMBtu	7.0E-06	3.9E-03	3.9E-03	2.0E-06
Phenol (HAP)	X	AP-42	lb/MMBtu	5.1E-05	2.9E-02	2.9E-02	1.4E-05
Propanal		AP-42	lb/MMBtu	3.2E-06	1.8E-03	1.8E-03	8.9E-07
Propionaldehyde (HAP)	X	AP-42	lb/MMBtu	6.1E-05	3.4E-02	3.4E-02	1.7E-05
Pyrene		AP-42	lb/MMBtu	3.7E-06	2.1E-03	2.1E-03	1.0E-06
Styrene (HAP)	X	AP-42	lb/MMBtu	1.9E-03	1.1E+00	1.1E+00	5.3E-04
2,3,7,8-Tetrachlorodibenzo-p-dioxins (H	X	AP-42	lb/MMBtu	8.6E-12	4.8E-09	4.8E-09	2.4E-12
Tetrachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	4.7E-10	2.6E-07	2.6E-07	1.3E-10
2,3,7,8-Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	9.0E-11	5.0E-08	5.0E-08	2.5E-11
Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	7.5E-10	4.2E-07	4.2E-07	2.1E-10
Tetrachlorobiphenyl		AP-42	lb/MMBtu	2.5E-09	1.4E-06	1.4E-06	7.0E-10
Tetrachloroethene		AP-42	lb/MMBtu	3.8E-05	2.1E-02	2.1E-02	1.1E-05
o-Tolualdehyde		AP-42	lb/MMBtu	7.2E-06	4.0E-03	4.0E-03	2.0E-06
p-Tolualdehyde		AP-42	lb/MMBtu	1.1E-05	6.2E-03	6.2E-03	3.1E-06
Toluene (HAP)	X	AP-42	lb/MMBtu	9.2E-04	5.1E-01	5.1E-01	2.6E-04
Trichlorobiphenyl		AP-42	lb/MMBtu	2.6E-09	1.5E-06	1.5E-06	7.3E-10
1,1,1-Trichloroethane		AP-42	lb/MMBtu	3.1E-05	1.7E-02	1.7E-02	8.7E-06
Trichloroethene		AP-42	lb/MMBtu	3.0E-05	1.7E-02	1.7E-02	8.4E-06
Trichlorofluoromethane		AP-42	lb/MMBtu	4.1E-05	2.3E-02	2.3E-02	1.1E-05
2,4,6-Trichlorophenol (HAP)	X	AP-42	lb/MMBtu	2.2E-08	1.2E-05	1.2E-05	6.2E-09
Vinyl Chloride (HAP)	X	AP-42	lb/MMBtu	1.8E-05	1.0E-02	1.0E-02	5.0E-06
o-Xylene (HAP)	X	AP-42	lb/MMBtu	2.5E-05	1.4E-02	1.4E-02	7.0E-06
Total HAPS				1.6E-02	9.0E+00	9.0E+00	4.5E-03
Largest Single HAP (Formaldehyde)						2.5E+00	1.2E-03

Potential Emissions Summary
Fire Pump
Berlin BioPower - Berlin, New Hampshire

Fire Pump	
Parameter	Diesel Fuel
Annual Operation	300 hr/yr
Fuel Consumption @ 100% Load:	16.2 gal/hr
Heat Input Rate	2.09 MMBtu/hr
Power Output	323.0 bhp

Pollutant	HAP's	Emission Factor Source	Diesel Fuel				
			Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate lb/yr	Emission Rate ton/yr
NOx		Cummings	g/bhp-hr	2.200	1.57	470	0.2
CO		Cummings	g/bhp-hr	1.417	1.01	303	0.2
SO2		AP-42	lb/MMBtu	0.0015	0.0031	1	0.0
PM10		Cummings	g/bhp-hr	0.118	0.084	25	0.0
PM2.5		Cummings	g/bhp-hr	0.118	0.084	25	0.0
CO2		AP-42	lb/MMBtu	164.00	342.06	102,618	51.3
VOC		Cummings	g/bhp-hr	0.123	0.088	26	0.0
Benzene (HAP)	X	AP-42	lb/MMBtu	9.33E-04	1.95E-03	1	0.00
Toluene (HAP)	X	AP-42	lb/MMBtu	4.09E-04	8.53E-04	0	0.00
Xylenes (HAP)	X	AP-42	lb/MMBtu	2.85E-04	5.94E-04	0	0.00
Propylene (HAP)	X	AP-42	lb/MMBtu	2.58E-03	5.38E-03	2	0.00
1,3-Butadiene (HAP)	X	AP-42	lb/MMBtu	3.91E-05	8.16E-05	0	0.00
Formaldehyde (HAP)	X	AP-42	lb/MMBtu	1.18E-03	2.46E-03	1	0.00
Acetaldehyde (HAP)	X	AP-42	lb/MMBtu	7.67E-04	1.60E-03	0	0.00
Acrolein (HAP)	X	AP-42	lb/MMBtu	9.25E-05	1.93E-04	0	0.00
Naphthalene (HAP)	X	AP-42	lb/MMBtu	8.48E-05	1.77E-04	0	0.00
Acenaphthylene		AP-42	lb/MMBtu	5.06E-06	1.06E-05	0	0.00
Acenaphthene		AP-42	lb/MMBtu	1.42E-06	2.96E-06	0	0.00
Fluorene		AP-42	lb/MMBtu	2.92E-05	6.09E-05	0	0.00
Phenanthrene		AP-42	lb/MMBtu	2.94E-05	6.13E-05	0	0.00
Anthracene		AP-42	lb/MMBtu	1.87E-06	3.90E-06	0	0.00
Fluoranthene		AP-42	lb/MMBtu	7.61E-06	1.59E-05	0	0.00
Pyrene		AP-42	lb/MMBtu	4.78E-06	9.97E-06	0	0.00
Benz(a)anthracene		AP-42	lb/MMBtu	1.68E-06	3.50E-06	0	0.00
Chrysene		AP-42	lb/MMBtu	3.53E-07	7.36E-07	0	0.00
Benzo(b)fluoranthene		AP-42	lb/MMBtu	9.91E-08	2.07E-07	0	0.00
Benzo(k)fluoranthene		AP-42	lb/MMBtu	1.55E-07	3.23E-07	0	0.00
Benzo(a)pyrene		AP-42	lb/MMBtu	1.88E-07	3.92E-07	0	0.00
Indeno(1,2,3-cd)pyrene		AP-42	lb/MMBtu	3.75E-07	7.82E-07	0	0.00
Dibenzo(a,h)anthracene		AP-42	lb/MMBtu	5.83E-07	1.22E-06	0	0.00
Benzo(g,h,l)perylene		AP-42	lb/MMBtu	4.89E-07	1.02E-06	0	0.00
Total PAH		AP-42	lb/MMBtu	1.68E-04	3.50E-04	0	0.00
Total HAPS				**0.0063704**	**1.03E-01**	**31**	**0.02**

Potential Emissions Summary
Cooling Tower
Berlin BioPower - Berlin New Hampshire

Cooling Tower Specification	Data Source	Data Result
Hours of Operation:		8,760 hours
Circulating Water Flow Rate:	SPX	60,000 gpm
Drift Eliminator Efficiency:	SPX	0.0005 %
Total Liquid Drift:	calc.	0.30 gpm
Density of Water:	constant	8.34 lb/gal
Total Liquid Drift:	calc.	150.1 lb/hr
Circulating Water TDS:	estimated	2,000 ppm
PM_{10} Emission Rate:	calc.	0.30 lb/hr
PM_{10} Emission Rate:	calc.	1.32 ton/yr

Calculations

Total Liquid Drift (gpm) = (Circulating Water Flow Rate, gpm) x (Drift Eliminator Efficiency, %)

Total Liquid Drift (lb/hr) = (Total Liquid Drift, gpm) x (Density of Water, lb/gal)

PM_{10} Emission Rate (lb/hr) = (Total Liquid Drift, lb/hr) x ((Circulating Water TDS, ppm) / 10^6)

PM_{10} Emission Rate (ton/yr) = (PM_{10} Emission Rate, lb/hr) x (Hours of Operation) x (1 ton / 2000 lbs)

Estimated PM, PM_{10}, and $PM_{2.5}$ Emissions Rates
Due To Wind Erosion on Outdoor Biomass Storage Piles
Berlin BioPower - Berlin, New Hampshire

Frequency of Disturbance (days per year)	365
Total Pile Area A (m2)	17399.1
Threshold Friction Velocity ut (m/s)	0.76
Anticipated Control Efficiency	0%

Disturbance*	Fastest Mile Wind speed for Disturbance $\mu^*_{z,I\,(m/s)}$	Reference Anemometer Height, z (m)	10-m Ref. Ht. Anemometer Fastest Mile $\mu^*_{10,I\,(m/s)}$	Friction Velocity $\mu^*_{10,I}$ (m/s)	Erosion Potential, P_i (gm/m^2)	Uncontrolled Fugitive Emission Rate, R (lbs/year) (For all disturbances)		
						PM	PM_{10}	$PM_{2.5}$
1/7/1999	20.1	100	15.43	0.82	1.71	66	33	5
4/8/1999	36.3	100	27.86	1.48	48.07	1844	922	138
4/8/1999	20.7	100	15.89	0.84	2.37	91	45	7
					TOTALS	**2000**	**1000**	**150**

* = The "Total Assumed Disturbances" represents the total number of days that the max wind speed was greater than the friction velocity (0.76) m/s.

	Footprint (Ft^2)	Equiv. Diameter (D)	Height (ft)	Surface Area (Ft^2)
Pile Sizes	53200	260.3	35	55091
	72600	304.0	35	74499
	55800	266.5	35	57692
			Total All Piles	**187282**

Estimated PM, PM_{10}, and $PM_{2.5}$ Emissions Rates
Due To Wood Pile Processing Operations

Process	Material Silt Content, S (%)	Material Moisture Content, M (%)	Number of Dozers (n)	Annual Operating Hours,t (hr)	Emission Factor, EF (lb/hr/dozer)			Short-Term PTE (lb/hr)			Long-Term PTE (lbs/year)		
					PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Buildozing on Wood Biomass Piles	0.16	37	1	8760	0.0082	0.0007	0.0001	0.0082	0.0007	0.0001	72	6	0.6

Estimated PM, PM_{10}, and $PM_{2.5}$ Emissions Rates
Due To Material Handling Operations

	Wood Aggregate Throughput, T			Effective Wood Aggregate Handled, T_{eff}				Air Pollution Emission Factor, EF (lb-emitted/ton-throughput)			Uncontrolled Maximum Hourly Air Pollutant Emissions, Q_u (lb/hr)			Uncontrolled Annual Air Pollutant Emissions, Q_u (lbs/yr)				Controlled Maximum Hourly Air Pollutant Emissions, Qu (lb/hr)			Controlled Annual Air Pollutant Emissions, Qu (ton/yr)		
Emission Source Operation	Maximum (ton/hr)	Average (ton/hr)	No. of Drop Points During handling, d	Hourly (ton/hr)	Annual (ton/yr)	Mean Wind Speed, U (mph)	Material Moisture Content, M (%)	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$	Control Efficiency, C (%)	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Truck Dumpers (3)	450	450	3	1350	1000000	3.79	37	0.00003	0.00001	0.000002	6.3	3.0	0.5	28	13	2	0%	6.3	3.0	0.5	28	13	2.0
Stockout Conveyor	250	250	1	250	1000000	3.79	37	0.00003	0.00001	0.000002	6.3	3.0	0.5	28	13	2	0%	6.3	3.0	0.5	28	13	2.0

Particle Size Multiplier		
PM	PM_{10}	$PM_{2.5}$
0.74	0.35	0.053

Potential Emissions Summary
Biomass Boiler - Normal Operation
Berlin BioPower - Berlin, New Hampshire

Biomass Boiler		
Parameter	Wood Fuel	
Annual Operation	8,694	hr/yr
Heat Input Rate @ 100% Load (37.6% fuel H2O, 60F ambient)	932.0	MMBtu/hr
Fuel Heat Rate (HHV)	5,061.6	Btu/lb
Fuel Input Rate	92.1	ton/hr

1,025 MMBtu/hr (Note: This heat input is for reference only and used to calculate lb/hr value to reflect vendor recommendation of 10% increase in the lb/hr value)
(The boiler vendors recommendation is based upon the stack test methods used and the relationship of theoretical exhaust flow to 'actual' exhaust flows encountered

Maximum Ambient Air Impact (from AERMOD modeling)
24-hour: 0.65964 ug/m3 @ 1 g/s
Annual: 0.07857 ug/m3 @ 1 g/s

Number of Turbines: 1

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate g/s	24-Hr Ambient Impacts (ug/m3)	24-Hr AAL (ug/m3)	Annual Ambient Impacts (ug/m3)	Annual AAL (ug/m3)	Emission Rate lb/yr	Emission Rate ton/yr
NOx		B&W	lb/MMBtu	0.060	61.5	7.8					534,785	267.4
CO		B&W	lb/MMBtu	0.075	76.9	9.7					668,482	334.2
SO2		B&W	lb/MMBtu	0.012	12.3	1.6					106,957	53.5
H2SO4 (assumes 10% SO2:SO3 Conv.)		Assumed	lb/MMBtu	0.002	1.9	0.2	0.16	0.71	0.019	0.48	16,378	8.2
PM (filterable)		B&W	lb/MMBtu	0.010	10.3	1.3					89,131	44.6
PM10 (filterable)		B&W	lb/MMBtu	0.010	10.3	1.3					89,131	44.6
PM2.5 (filterable)		B&W	lb/MMBtu	0.010	10.3	1.3					89,131	44.6
CO2		B&W	lb/MMBtu	221.0	206,000	25,956.0					1,790,964,000	895,482
NH3 (assumes 20 ppm slip)		Assumed	lb/MMBtu	0.012	12.5	1.6	1.04	100.00	0.12	100	109,046	54.5
VOC		B&W	lb/MMBtu	0.010	10.3	1.3					89,131	44.6
Antimony (HAP)	X	AP-42	lb/MMBtu	7.9E-06	8.1E-03	1.02E-03	6.73E-04	1.8	8.02E-05	1.2	70	0.035
Arsenic (HAP)	X	AP-42	lb/MMBtu	2.2E-05	2.3E-02	2.84E-03	0.0019	0.036	2.23E-04	0.02	196	0.098
Barium		AP-42	lb/MMBtu	1.7E-04	1.7E-01	2.20E-02	0.0145	2.5	1.73E-03	1.7	1,515	0.758
Beryllium (HAP)	X	AP-42	lb/MMBtu	1.1E-06	1.1E-03	1.42E-04	9.37E-05	0.0071	1.12E-05	0.0048	10	0.005
Cadmium (HAP)	X	AP-42	lb/MMBtu	4.1E-06	4.2E-03	5.30E-04	3.49E-04	0.036	4.16E-05	0.024	37	0.018
Chromium, Total (HAP)	X	AP-42	lb/MMBtu	2.1E-05	2.2E-02	2.71E-03	0.0018	0.036	2.13E-04	0.024	187	0.094
Cobalt (HAP)	X	AP-42	lb/MMBtu	6.5E-06	6.7E-03	8.40E-04	5.54E-04	0.07	6.60E-05	0.05	58	0.029
Copper		AP-42	lb/MMBtu	4.9E-05	5.0E-02	6.33E-03	0.0042	0.71	4.97E-04	0.48	437	0.218
Iron		AP-42	lb/MMBtu	9.9E-04	1.0E+00						8,824	4.412
Lead (HAP)	X	AP-42	lb/MMBtu	4.8E-05	4.9E-02	6.20E-03	0.0041	0.18	4.87E-04	0.12	428	0.214
Manganese (HAP)	X	AP-42	lb/MMBtu	1.6E-03	1.6E+00	2.07E-01	0.14	1.00	1.62E-02	0.05	14,261	7.130
Mercury (HAP)	X	MACT	lb/MMBtu	3.0E-06	3.1E-03	3.88E-04	2.56E-04	0.30	3.04E-05	0.30	27	0.013
Molybdenum		AP-42	lb/MMBtu	2.1E-06	2.2E-03	2.71E-04	1.79E-04	1.80	2.13E-05	1.20	19	0.009
Nickel (HAP)	X	AP-42	lb/MMBtu	3.3E-05	3.4E-02			0.36		0.24	294	0.147
Phosphorous		AP-42	lb/MMBtu	2.7E-05	2.8E-02			NA		NA	241	0.120
Potassium		AP-42	lb/MMBtu	3.9E-02	4.0E+01			NA		NA	347,610	173.805
Selenium (HAP)	X	AP-42	lb/MMBtu	2.8E-06	2.9E-03	3.62E-04	2.39E-04	0.71	2.84E-05	0.48	25	0.012
Silver		AP-42	lb/MMBtu	1.7E-03	1.7E+00	2.20E-01	0.14	0.50	0.017	0.34	15,152	7.576
Sodium		AP-42	lb/MMBtu	3.6E-04	3.7E-01			NA		NA	3,209	1.604
Strontium		AP-42	lb/MMBtu	1.0E-05	1.0E-02			NA		NA	89	0.045
Tin		AP-42	lb/MMBtu	2.3E-05	2.4E-02	2.97E-03	0.00196	0.36	2.33E-04	0.24	205	0.103
Titanium		AP-42	lb/MMBtu	2.0E-05	2.1E-02			NA		NA	178	0.089
Vanadium		AP-42	lb/MMBtu	9.8E-07	1.0E-03			NA		NA	9	0.004
Yttrium		AP-42	lb/MMBtu	3.0E-07	3.1E-04	3.88E-05	2.56E-05	15.00	3.04E-06	9.90	3	0.001
Zinc		AP-42	lb/MMBtu	4.2E-04	4.3E-01	5.43E-02	0.036	25.00	4.26E-03	17	3,743	1.872
Acenaphthene		AP-42	lb/MMBtu	9.1E-07	9.3E-04			NA		NA	8	0.004
Acenaphthylene		AP-42	lb/MMBtu	5.0E-06	5.1E-03			NA		NA	45	0.022
Acetaldehyde (HAP)	X	AP-42	lb/MMBtu	8.3E-04	8.5E-01	1.07E-01	0.071	161	8.42E-03	9	7,398	3.699
Acetone		AP-42	lb/MMBtu	1.9E-04	1.9E-01	2.45E-02	0.016	4,243	1.93E-03	2,829	1,693	0.847
Acetophenone (HAP)	X	AP-42	lb/MMBtu	3.2E-09	3.3E-06	4.13E-07	2.73E-07	246	3.25E-08	164	0	0.000
Acrolein (HAP)	X	Bridgewater	lb/MMBtu	4.3E-05	4.4E-02	5.55E-03	0.00366	0.82	4.36E-04	0.02	383	0.192
Anthracene		AP-42	lb/MMBtu	3.0E-06	3.1E-03			NA		NA	27	0.013
Benzaldehyde		AP-42	lb/MMBtu	8.5E-07	8.7E-04			NA		NA	8	0.004
Benzene (HAP)	X	AP-42	lb/MMBtu	4.2E-03	4.3E+00	5.43E-01	0.36	5.70	4.26E-02	3.80	37,435	18.717
Benzo(a)anthracene		AP-42	lb/MMBtu	6.5E-08	6.7E-05	8.40E-06	5.54E-06	0.36	6.60E-07	0.24	1	0.000
Benzo(a)pyrene		AP-42	lb/MMBtu	2.6E-06	2.7E-03	3.36E-04	2.22E-04	0.0050	2.64E-05	0.0050	23	0.012
Benzo(b)fluoranthene		AP-42	lb/MMBtu	1.0E-07	1.0E-04	1.29E-05	8.52E-06	0.36	1.01E-06	0.24	1	0.000
Benzo(e)pyrene		AP-42	lb/MMBtu	2.6E-09	2.7E-06			NA		NA	0	0.000
Benzo(g,h,i)perylene		AP-42	lb/MMBtu	9.3E-08	9.5E-05			NA		NA	1	0.000
Benzo(j,k)fluoranthene		AP-42	lb/MMBtu	1.6E-07	1.6E-04			NA		NA	1	0.001
Benzo(k)fluoranthene		AP-42	lb/MMBtu	3.6E-08	3.7E-05			NA		NA	0	0.000
Benzoic acid		AP-42	lb/MMBtu	4.7E-08	4.8E-05			NA		NA	0	0.000
bis(2-Ethylhexyl)phthalate (HAP)	X	AP-42	lb/MMBtu	4.7E-08	4.8E-05			NA		NA	0	0.000
Bromomethane		AP-42	lb/MMBtu	1.5E-05	1.5E-02			NA		NA	134	0.067
2-Butanone (MEK)		AP-42	lb/MMBtu	5.4E-06	5.5E-03	6.98E-04	4.60E-04	5,000.00	5.48E-05	5,000	48	0.024
Carbazole	X	AP-42	lb/MMBtu	1.8E-06	1.8E-03			NA		NA	16	0.008
Carbon tetrachloride (HAP)	X	AP-42	lb/MMBtu	4.5E-05	4.6E-02	5.81E-03	0.0038	111.00	4.57E-04	74	401	0.201
Chlorine (HAP)	X	AP-42	lb/MMBtu	7.9E-04	8.1E-01	1.02E-01	0.067	7.50	8.02E-03	5	7,041	3.521
Chlorobenzene (HAP)	X	AP-42	lb/MMBtu	3.3E-05	3.4E-02	4.26E-03	0.0028	231.00	3.35E-04	154	294	0.147
Chloroform (HAP)	X	AP-42	lb/MMBtu	2.8E-05	2.9E-02	3.62E-03	0.0024	175.00	2.84E-04	117	250	0.125
Chloromethane		AP-42	lb/MMBtu	2.3E-05	2.4E-02	2.97E-03	0.0020	621.00	2.33E-04	414	205	0.103
2-Chloronaphthalene		AP-42	lb/MMBtu	2.4E-09	2.5E-06			NA		NA	0	0.000
2-Chlorophenol		AP-42	lb/MMBtu	2.4E-08	2.5E-05			NA		NA	0	0.000
Chrysene		AP-42	lb/MMBtu	3.8E-08	3.9E-05	4.91E-06	3.24E-06	0.36	3.86E-07	0.24	0	0.000
Crotonaldehyde		AP-42	lb/MMBtu	9.9E-06	1.0E-02	1.28E-03	8.44E-04	3.10	1.00E-04	2	88	0.044

Pollutant	HAP	Emission Factor Source	Emission Factor Units	Emission Factor	Emission Rate lb/hr	Emission Rate g/s	24-Hr Ambient Impacts (ug/m3)	24-Hr AAL (ug/m3)	Annual Ambient Impacts (ug/m3)	Annual AAL (ug/m3)	Emission Rate lb/yr	Emission Rate ton/yr
Decachlorobiphenyl		AP-42	lb/MMBtu	2.7E-10	2.8E-07			NA		NA	0	0.000
Dibenzo(a,h)anthracene		AP-42	lb/MMBtu	9.1E-09	9.3E-06			NA		NA	0	0.000
1,2-Dibromoethene		AP-42	lb/MMBtu	5.5E-05	5.6E-02			NA		NA	490	0.245
Dichlorobiphenyl		AP-42	lb/MMBtu	7.4E-10	7.6E-07			NA		NA	0	0.000
1,2-Dichloroethane		AP-42	lb/MMBtu	2.9E-05	3.0E-02			NA		NA	258	0.129
Dichloromethane		AP-42	lb/MMBtu	2.9E-04	3.0E-01	3.75E-02	0.025	621	#####	414	2,585	1.292
1,2-Dichloropropane		AP-42	lb/MMBtu	3.3E-05	3.4E-02	4.26E-03	0.0028	232	#####	4.0	294	0.147
2,4-Dinitrophenol		AP-42	lb/MMBtu	1.8E-07	1.8E-04						2	0.001
Ethylbenzene (HAP)	X	AP-42	lb/MMBtu	3.1E-05	3.2E-02	4.00E-03	0.0026	619	#####	412	276	0.138
Fluoranthene		AP-42	lb/MMBtu	1.6E-06	1.6E-03			NA		NA	14	0.007
Fluorene		AP-42	lb/MMBtu	3.4E-06	3.5E-03			NA		NA	30	0.015
Formaldehyde (HAP)	X	AP-42	lb/MMBtu	4.4E-03	4.5E+00	5.68E-01	0.37	1.3	#####	0.9	39,218	19.609
Heptachlorobiphenyl		AP-42	lb/MMBtu	6.6E-11	6.8E-08			NA		NA	0	0.000
Hexachlorobiphenyl		AP-42	lb/MMBtu	5.5E-10	5.6E-07			NA		NA	0	0.000
Hexanal		AP-42	lb/MMBtu	7.0E-06	7.2E-03			NA		NA	63	0.031
Heptachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	2.0E-09	2.1E-06			NA		NA	0	0.000
Heptachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.4E-10	2.5E-07			NA		NA	0	0.000
Hexachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.6E-06	1.6E-03			NA		NA	14	0.007
Hexachlorodibenzo-p-furans		AP-42	lb/MMBtu	2.8E-10	2.9E-07			NA		NA	0	0.000
Hydrogen Chloride (HAP)	X	NHDES Test Data	lb/MMBtu	8.3E-04	8.6E-01	1.08E-01	0.071	20	#####	20	7,434	3.717
Indeno(1,2,3,c,d)pyrene		AP-42	lb/MMBtu	8.7E-08	8.9E-05			NA		NA	1	0.000
Isobutyraldehyde		AP-42	lb/MMBtu	1.2E-05	1.2E-02			NA		NA	107	0.053
Methane		AP-42	lb/MMBtu	2.1E-02	2.2E+01			NA		NA	187,175	93.587
2-Methylnaphthalene		AP-42	lb/MMBtu	1.6E-07	1.6E-04			NA		NA	1	0.001
Monochlorobiphenyl		AP-42	lb/MMBtu	2.2E-10	2.3E-07			NA		NA	0	0.000
Naphthalene (HAP)	X	AP-42	lb/MMBtu	9.7E-05	9.9E-02	1.25E-02	0.0083	186	#####	3	865	0.432
2-Nitrophenol		AP-42	lb/MMBtu	2.4E-07	2.5E-04			NA		NA	2	0.001
4-Nitrophenol (HAP)	X	AP-42	lb/MMBtu	1.1E-07	1.1E-04						1	0.000
Octachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	6.6E-08	6.8E-05			NA		NA	1	0.000
Octachlorodibenzo-p-furans		AP-42	lb/MMBtu	8.8E-11	9.0E-08			NA		NA	0	0.000
Pentachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	1.5E-09	1.5E-06			NA		NA	0	0.000
Pentachlorodibenzo-p-furans		AP-42	lb/MMBtu	4.2E-10	4.3E-07			NA		NA	0	0.000
Pentachlorobiphenyl		AP-42	lb/MMBtu	1.2E-09	1.2E-06			NA		NA	0	0.000
Pentachlorophenol (HAP)	X	AP-42	lb/MMBtu	5.1E-08	5.2E-05	6.59E-06	4.35E-06	1.8	#####	1.2	0	0.000
Perylene		AP-42	lb/MMBtu	5.2E-10	5.3E-07			NA		NA	0	0.000
Phenanthrene		AP-42	lb/MMBtu	7.0E-06	7.2E-03	9.04E-04	0.00060	0.7	#####	0.5	62	0.031
Phenol (HAP)	X	AP-42	lb/MMBtu	5.1E-05	5.2E-02	6.59E-03	0.0043	68	#####	45	455	0.227
Propanal		AP-42	lb/MMBtu	3.2E-06	3.3E-03			NA		NA	29	0.014
Propionaldehyde (HAP)	X	AP-42	lb/MMBtu	6.1E-05	6.3E-02	7.88E-03	0.005	239	#####	159	544	0.272
Pyrene		AP-42	lb/MMBtu	3.7E-06	3.8E-03	4.78E-04	0.00032	0.71	#####	0.5	33	0.016
Styrene (HAP)	X	AP-42	lb/MMBtu	1.9E-03	1.9E+00	2.45E-01	0.16	1,000	#####	1,000	16,935	8.467
2,3,7,8-Tetrachlorodibenzo-p-dioxins (HAP)	X	AP-42	lb/MMBtu	8.6E-12	8.8E-09			NA		NA	0	0.000
Tetrachlorodibenzo-p-dioxins		AP-42	lb/MMBtu	4.7E-10	4.8E-07			NA		NA	0	0.000
2,3,7,8-Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	9.0E-11	9.2E-08			NA		NA	0	0.000
Tetrachlorodibenzo-p-furans		AP-42	lb/MMBtu	7.5E-10	7.7E-07			NA		NA	0	0.000
Tetrachlorobiphenyl		AP-42	lb/MMBtu	2.5E-09	2.6E-06			NA		NA	0	0.000
Tetrachloroethene		AP-42	lb/MMBtu	3.8E-05	3.9E-02			NA		NA	339	0.169
o-Tolualdehyde		AP-42	lb/MMBtu	7.2E-06	7.4E-03			NA		NA	64	0.032
p-Tolualdehyde		AP-42	lb/MMBtu	1.1E-05	1.1E-02			NA		NA	98	0.049
Toluene (HAP)	X	AP-42	lb/MMBtu	9.2E-04	9.4E-01	1.19E-01	7.84E-02	5,000	#####	5,000	8,208	4.104
Trichlorobiphenyl		AP-42	lb/MMBtu	2.6E-09	2.7E-06			NA		NA	0	0.000
1,1,1-Trichloroethane		AP-42	lb/MMBtu	3.1E-05	3.2E-02			NA		NA	276	0.138
Trichloroethene		AP-42	lb/MMBtu	3.0E-05	3.1E-02			NA		NA	267	0.134
Trichlorofluoromethane		AP-42	lb/MMBtu	4.1E-05	4.2E-02	5.30E-03	0.0035	28,270	#####	18,846	365	0.183
2,4,6-Trichlorophenol (HAP)	X	AP-42	lb/MMBtu	2.2E-08	2.3E-05	2.84E-06	1.87E-06	3	#####	3	0	0.000
Vinyl Chloride (HAP)	X	AP-42	lb/MMBtu	1.8E-05	1.8E-02	2.33E-03	0.0015	9.3	#####	6.2	160	0.080
o-Xylene (HAP)	X	AP-42	lb/MMBtu	2.5E-05	2.6E-02	3.23E-03	0.0021	1,550	#####	100	223	0.111
Total HAPS				0.016057433	1.6E+01						143,121	71.561
Largest Single HAP (Formaldehyde)											37,260	18.630

originally installed in 1966 and refurbished in 1993. A bubbling fluidized bed (BFB), which represents highly efficient and advanced biomass combustion and power conversion technology, will be installed at the base of the boiler in place of the existing black liquor firing and recovery systems. A new fabric filter ("baghouse") system will be installed to control particulate emissions and a new selective catalytic reduction (SCR) system will be added to control NO_x emissions. A dry sorbent injection system will also be installed to assure compliance with the specified sulfur dioxide emission limitation. The boiler and emissions control systems will be enclosed within a building (the "boiler building"), which will minimize noise impacts in the surrounding community and provide an aesthetically appropriate exterior finish, similar to a large commercial building.

Deleted: The existing electrostatic precipitator (ESP)

Deleted: used

Deleted: will be refurbished or upgraded

Development of the overall Facility will also include construction of a new turbine building adjacent to the boiler building, which will house the steam turbine generator. A new cooling tower will be installed near the western edge of the property behind the boiler building. Two wood fuel off-loading and storage areas will be developed. Each wood handling and storage area will be paved and systems will be installed to properly manage stormwater. The fuel handling and storage area closest to the boiler will serve as the main fuel yard. Trucks delivering wood fuel to this area will be off loaded using three tilting truck dumpers. A rail siding that previously existed on the Site will also be re-constructed to allow for deliveries of wood fuel to the Site. The wood yard on the north east portion of the Site will be equipped with a single tilting truck dumper to accommodate delivery of wood chips, along with equipment to off-load whole logs. Equipment will be installed within a new building in this area to produce wood chips from whole logs. Chips produced in this area, along with those delivered directly to the main fuel yard will be mechanically conveyed to a wood processing building to assure uniform wood chip size. From the wood processing building, the chips will be conveyed into the boiler or returned to one of the storage piles adjacent to the boiler building in the main fuel yard.

An electric transmission interconnection line will be installed between the site and the existing high voltage transmission line operated by Public Service Company of New Hampshire (PSNH). A small switchyard will be installed adjacent to the turbine building, which will provide necessary power isolation systems and a step up transformer to increase the voltage of the power produced by the steam turbine generator to 115 kVA, consistent with the PSNH transmission line. From the switchyard, an underground transmission cable will be installed along the route of an existing underground pipe formerly used to transport pulp from the site to the Fraser Gorham paper mill. The underground pipe exits the Site near the intersection of Coos and Community Streets and generally follows the route of the former rail line from the Site to Shelby Street and Devent Street. The transmission cable will transition to an overhead line approximately 0.75 miles south of the Site and 0.1 miles northwest of the existing PSNH East Side substation. The overhead transmission line will be installed within the existing cleared corridor between Devent Street and the PSNH substation.

Deleted: first through a new on-site duct bank, and then through

In early December 2009, Laidlaw received the final version of an interconnection feasibility study (see body of the report provided in Appendix Q) from the Independent System Operator of the New England ("ISO-NE") transmission system the entity charged with oversight over the local transmission system. The results indicate that Laidlaw's project will be able to connect to the transmission system with upgrades estimated to be less than $1 million. The Study takes into account all existing facilities

Pollutants ("HAPs") will meet levels deemed Maximum Achievable Control Technology ("MACT") for wood fueled boilers.

A new fabric filter ("baghouse") system will be installed to achieve a particulate emission rate less than 0.010 pounds per million Btu of heat input to the boiler ("lbs/MMBtu"). This emission rate is approximately one-half of the applicable regulatory limit. A new SCR system will be installed following the ESP to control emissions of NO_X to no more than 0.060 lbs/MMBtu, a level previously deemed as LAER by the New Hampshire Department of Environmental Services, Air Resources Division ("ARD"). Sulfur dioxide emissions will be minimized to less than 0.012 lbs/MMBtu based on the inherently low sulfur content of wood, and use of a dry sorbent injection system as needed to maintain compliance with the emission limit. Emissions of carbon monoxide ("CO") and volatile organic compounds ("VOC") that typically result from incomplete fuel combustion will be minimized by the advanced and highly efficient BFB combustion technology that will be installed in the boiler. Emissions of sulfur compounds and trace metals will be minimized by the inherently clean composition of the wood fuel.

Deleted: The existing ESP will be refurbished upgraded up to and including the possible addition of a third parallel ESP chamber,

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The ambient air quality impacts resulting from the boiler and the emissions control technologies summarized above have been evaluated using computer dispersion models approved by the US EPA and NH DES. The impacts to air quality are well below the levels established in the National Ambient Air Quality Standards ("NAAQS"), which have been developed to be protective of human health and the environment, including a margin of safety, for even the most sensitive of the population.

The Project will be subject to stringent ongoing performance testing, monitoring, recordkeeping and reporting to both NHDES and US EPA over its operating life to assure that the actual emissions from the Facility meet the proposed limits.

Noise

The Project has been designed with advanced equipment and added noise suppression measures to assure that the Project will not exceed the selected reference criteria for impacts in the surrounding community which mirror the level contained in the City of Berlin's noise performance standards. The primary sources of noise will be the boiler, ancillary plant equipment (fans, pumps, etc.), the cooling tower, wood unloading equipment, wood processing equipment (chippers and screen), an electric transformer, and mobile equipment such as fuel delivery trucks, front end loaders, and other equipment handling wood in the two wood yards. The boiler, its major supporting equipment, and the wood processing equipment will be located within buildings and/or in enclosures designed to reduce sound transmittance. Barrier walls will be installed near the cooling tower to reduce cooling tower sound levels at the nearby property line. A barrier wall will similarly be installed in the switchyard area to reduce off site noise impacts

[6] BACT applies to those criteria pollutants for which the ambient air quality meets National Ambient Air Quality Standards. LAER applies to any criteria pollutants for which the ambient air quality exceeds NAAQS. In the case of the proposed Project, LAER

When the transformers arrive on site, they will be installed, and an initial backfeed to the main transformer will be performed. As the equipment installation and final connections of piping and wiring is nearing completion, the process of checking the electrical and control systems, starting up major equipment, cleaning pipelines, and testing all systems will begin.

When the "cold" commissioning process described above is complete, "hot" commissioning will begin with the first fire of the boiler. All of the safety systems of the plant will be thoroughly tested and confirmed. The plant will then undergo emissions testing and performance testing, confirming that all guarantees and specifications have been met. With the completion of the final performance run and acceptance by the equipment manufacturer and owner, the plant will be declared ready for commercial operation.

(g) ASSOCIATED TRANSMISSION LINE INFORMATION

(1) Location shown on U.S. Geological Survey Map

The regional transmission line with which the Facility will interconnect is shown in Figure (g)(1)-1. The route of the Project's electric transmission interconnection is shown in Figures (g)(1)-2. The route and transmission interconnection system is described below.

(2) Corridor width for:

a. New route

The transmission line from the Site will be a new 115kV cable installed within a trench along the route of an existing underground 18-inch diameter fiberglass reinforced pipe formerly used to transport pulp from the Pulp Mill to Fraser's Paper Mill in Gorham. The underground pipe leaves the Site near the intersection of Coos and Community Streets and generally follows the route of the former rail bed from the south end of the Site to the north end of Shelby Street. The pipe follows Shelby Street and Devent Street along a right-of-way that is currently under easement control of LBB. The cable will transition to overhead conductors at the east side of Devent Street to the existing PSNH East Side Substation 300. The overhead conductors will run on one or two new steel monopole towers along with the existing Smith Hydro Z177 Line to the substation a distance of approximately 800 feet including elevation change.

b. Widening along existing route

The existing underground system will not require widening. There will be a pulling manhole installed at the Site and at least two more pulling manholes along the existing effluent pipe right-of-way. These manholes will be temporary and backfilled upon completion of the cable installation. There may be some clearing south of the existing Z177 line from Smith Hydro from Devent Street up the hill to the PSNH substation.

(3) Length of line

The length of the underground portion of the transmission line off from the Project Site is estimated at 3,200 feet and the portion above ground at 800 feet.

(4) Distance along new route

The distance along the new route is the underground portion of 3,200 feet.

(5) Distance along existing route

The distance along the existing route is the 800-foot long portion of the line that will be installed above ground from Devent Street to the substation. The overhead line will follow a cleared transmission corridor that includes several other existing overhead lines.

(6) Voltage (design rating)

The system is designed for 115 kV nominal.

(7) Any associated new generating unit or units

Same as application information (f) above.

(8) Type of construction (described in detail)

The 115 kV cable will be XLPE insulated single conductor installed within a trench that conforms to all applicable codes and PSNH requirements. The overhead line construction will have a transition tower from underground to overhead. The conductor will be 477 kcmil ACSR and extend to a dual circuit steel monopole that will carry this conductor and the existing Smith Hydro Z177 line on the same structure into the PSNH East Side Substation 300.

Deleted: n electrical duct bank system

Deleted: The electrical duct bank system will consist of electrical HDPE electrical conduits that are supported with spacers and filled with pourable grout that forms the electrical conduit duct bank.

(9) Construction schedule, including start date and scheduled completion date

The construction period for the electric transmission interconnection is expected to be six months. The facilities would need to be completed in time to "backfeed" power to the facility for startup and testing. It is estimated that the work would start in August 2011 and be completed by February 2012.

(10) Impact on system stability and reliability

Please refer to section (f)(3)(e) above.

(h) ADDITIONAL INFORMATION

(1) A description in detail of the type and size of each major part of the proposed facility

The Facility will be a base loaded electric energy generating facility with an expected nominal gross electrical output of approximately 70 MW. The heart of the Facility will be a BFB boiler; a highly efficient and advanced technology for the conversion of biomass fuel to energy. The boiler and other major components of the Project are described below.

(i) Biomass Boiler & Steam Generator

The existing B&W recovery boiler will be converted to a biomass-fueled BFB boiler with air-locked hopper bottoms for removal of bed sand particles and other non-combustible materials. An air distribution system consisting of fluidizing air and overfire air will be added to assure efficient fuel combustion. A flue gas recirculation system will be utilized to adjust the bed temperature depending on the moisture content of the incoming fuel. The existing feedwater economizer, which will preheat the feedwater to the boiler drum, will be modified to optimize boiler efficiency. The use of a tubular air pre-heater will ensure efficient use of the energy released in the boiler.

The boiler will be capable of generating up to 600,000 pounds per hour of steam at temperatures up to 900°F and 850 psig. Stable operation and compliant emission levels will be maintained over the range of expected operating loads from 70% to 100% of maximum steam output. A series of double sided retractable soot blowers will be utilized on heat transfer surfaces within the superheater and convective sections of the boiler to maintain design performance levels.

The boiler will be capable of firing clean biomass and has been designed to handle variable fuel moisture contents ranging from 35% up to 50%. At an average moisture content of 37.6%[10], the wood fuel will have a higher heating value of approximately 5,060 Btu/lb. The heat input rate to the boiler will vary primarily depending on the moisture content of the wood fuel. The average heat input rate at maximum steam load will be 932 MMBtu/hr with 37.6% moisture content fuel. The maximum heat input rate will be 1,013 MMBtu/hr with 50% moisture content fuel. Individual fuel feeders will be equipped with adjustable air swept distributors to adjust the flow of fuel into the boiler. The fuel chutes will each be equipped with backdraft dampers.

The boiler will also be equipped with four No. 2 distillate oil fired burners for use during startup, with a maximum expected heat input capacity of 240 MMBtu/hr. The Facility will also include a diesel engine driven fire pump with a mximum power output rating of 323 HP. The boiler startup burners and the diesel fire pump will be fired with ULSD fuel which will be stored on-site in a 50,000 gallon storage tank equipped with secondary containment.

Deleted: 500 kW emergency diesel generator set and a 288 horsepower

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[10] This fuel moisture content has been established as the design point for equipment supplier performance guarantee purposes.

manual reclaiming of fuel from the unprocessed fuel storage area. Each hopper will discharge to a common 250 ton per hour unprocessed fuel out-feed conveyer, which will supply the fuel processing system.

A magnet will be installed over the truck dumper outfeed conveyer near the processing building. A disc screen capable of processing 250 tons per hour will be used to screen the unprocessed wood for boiler fuel. Two wood hogs will be used to reduce the wood fuel from the disc screen to a three inch minus size. Each hog will be capable of processing up to 75 tons per hour of wood fuel.

A 250 ton per hour stockout conveyer will receive the discharge from the processing building and convey it to the processed wood fuel storage area. The processed wood fuel storage area will be open and on paved ground with an under drain system to remove rain water from the storage area. The paved pile area will have a perimeter drain system.

Three 50 ton per hour mechanical reclaim hoppers located under the storage area will supply a single boiler feed conveyer. The boiler feed conveyer will feed the shuttle conveyers which will distribute fuel to individual boiler chutes. A single return conveyer will return excess fuel to the wood storage area. Each fuel metering bin will be equipped with screw feeders to meter wood fuel to the boiler feed chutes. There will be one inverted cone type chute connecting each pneumatic distributor on the boiler with a set of feeders at the metering bin.

(iii) Ash Handling Systems

The ash handling facilities will consist of separate collection and storage systems for fly ash, and for bed sand removal, screening and re-injection.

Fly ash will be continuously collected from the baghouse using a dry mechanical system. Collected fly ash will be conveyed to a dry storage bin inside of the boiler building. The storage capacity will be sufficient to accept a minimum of twenty four hours of full-load operation. There will be an atmospheric vent on the ash silo equipped with a filter to minimize fugitive emissions. Ash from the elevated storage bin will be processed through a pug mill which mixes dry fly ash with water to produce a wet cake that minimizes dust generation during subsequent handling. The wetted fly ash will then be loaded onto trucks and transported off site for disposal or for beneficial re-use in agricultural land applications. LBB has confirmed that the ash can accepted and disposed at the nearby Mount Carberry landfill if not acceptable for beneficial re-use and until such time as adequate ash analytical data is available to file an application with DES for re-use of the material.

Deleted: electrostatic precipitator and mechanical dust collector hoppers

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Bottom ash is virtually non-existent in a fluid bed boiler. Fuel is continually recirculated within the fluidized bed until fully combusted. A small stream of sand from the bed is continually withdrawn, screened and returned to the boiler, along with additional make-up sand as required. A small amount of noncombustible material such as rock, slag, glass or metal, is screened out of the bed material and collected for periodic disposal. The sand silo

The primary source of water for fire protection will also be City water. A diesel engine-driven fire pump will be used as a backup system. The entire wood storage area and power block will be served by an underground hydrant system. A wet standpipe system will be installed in all heated buildings. Unheated buildings and wood conveyers will be served by a dry standpipe with sprinklers. Portable hand extinguishers will be located throughout the Facility. Office areas will be equipped with wet pipe sprinkler systems. The steam turbine generator, lube oil tank area and the main transformer will be served with a fire protection system that will meet applicable codes and the requirements of the local Fire Chief. All fire detection and alarm systems will be installed to meet their respective codes and the requirements of the local Fire Chief.

(v) Air Pollution Control Systems

The BFB technology used in the Project's combustion system represents a highly efficient system for biomass fuel conversion and results in low levels of combustion emissions. Through good combustion efficiency, the BFB technology generates low emissions of pollutants resulting from incomplete combustion such as CO and VOC. The combustion system also incorporates FGR, a technology that helps to control combustion temperatures and therefore reduces the formation of NO_X.

In addition to the inherently low emitting technology associated with the combustion system, the Project will incorporate a number of additional systems that represent Best Available Control Technology and Lowest Achievable Emission Rate technology to further minimize air emissions.

A new fabric filter ("baghouse") system will be installed to maximize control of particulate emissions and meet the BACT emission limits. The baghouse will provide greater than 99% control of particulate.

Deleted: The existing ESP will be upgraded, up to and including the possible addition of a third parallel ESP chamber,

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An SCR system will be installed to minimize NO_X emissions. The SCR system will utilize aqueous ammonia (NH_3) that will be injected into the flue gas in a stoichiometric ratio proportional to the mass of NO_X to be removed. The flue gas and NH_3 will pass through a catalyst bed where NO_X in the flue gas will be converted into diatomic nitrogen and water. An ammonia injection control system will be installed to accurately inject the needed amount of ammonia into the flue gas stream upstream of the catalyst to provide optimal conditions for the control and minimization of both NO_X and NH_3 and assure compliance with permit limits. The dilute liquid NH_3 for the SCR system will be stored on-site in a 19% aqueous solution in a 10,000 gallon storage tank equipped with secondary containment. The tank will provide sufficient storage for up to ten days of boiler operation, requiring only a single tanker truck delivery per week. The NH_3 storage tank will include an unloading system to accept deliveries by truck.

A new dry sorbent injection system will be installed that will introduce limestone or a similar agent into the boiler flue gas path at the appropriate temperature to effectively control emissions of sulfur dioxide.

70% of NO_X emissions formed within the boiler. The SCR system will inject vaporized aqueous NH_3 into the hot exhaust gas path which will react with the NOx in the exhaust gas to form nitrogen and water vapor as the exhaust gases pass through the catalyst beds. The use of the BFB technology, clean wood fuel, good combustion practices, and SCR will result in a NO_X emission rate from the biomass boiler no greater than 0.060 lb/MMBtu of heat input based on a 30-day rolling average during normal operation.

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Carbon Monoxide

CO emissions are associated with incomplete combustion of fuel in a boiler. These emissions will be minimized by utilizing the highly efficient BFB combustion technology. The wood fuel will be combusted in a heated bed of sand-like material which is fluidized within a rising column of air. The hot bed material effectively liberates the carbon in the wood fuel, which allows the oxygen (O_2) in the combustion air to more freely react with the fuel, resulting in an efficient combustion process. The air to fuel ratio and combustion temperature in the boiler will be optimized and monitored to achieve the desired balance between CO and NO_X emissions. As mentioned earlier, the Facility also will utilize a fuel preparation system that will help optimize the quality, size and moisture content to promote efficient combustion, which will also help mitigate CO formation. The use of BFB combustion technology in the boiler design, good combustion practices, and fuel type will result in a CO emission rate from the biomass boiler no greater than 0.075 lb/MMBtu of heat input based on a 24-hour daily block average during normal operation.

Sulfur Dioxide/Sulfuric Acid Mist

Emissions of sulfur compounds result from oxidation of sulfur contained in a fuel. The Facility will utilize wood fuel which has an inherently low sulfur content, in combination with a dry sorbent injection system on an as-needed basis, to maintain SO_2 no greater than 0.012 lb/MMBtu of heat input during normal operation. The characteristics of wood fly ash also serve to capture much of the sulfur compounds and further minimize emissions. Based on experience with other generating facilities using an SCR control system, no more 10% of the SO_2 generated in the boiler is expected to be further oxidized to SO_3 and combine with water vapor in the flue gas to produce sulfuric acid mist (H_2SO_4). The resulting H_2SO_4 emission rate is expected to be less than 0.002 lbs/MMBtu of heat input.

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Particulate Matter

Particulate matter is generated in a boiler by incomplete combustion and the non-combustible fraction of a fuel. The BFB combustion technology and operating controls provide a greater degree of complete combustion than most other wood fired boiler designs. The boiler's fabric filter baghouse will abate over 99 percent of the particulate emissions formed in the boiler. These measures will result in a filterable $PM/PM_{10}/PM_{2.5}$ emission rate no greater than 0.010 lb/MMBtu of heat input during normal operation.

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The potential emissions during startup periods have been estimated on Table (h)(3)(i)-3. These boiler startup emissions estimates are conservatively based on a total of 4 cold starts per year of the biomass boiler. These estimates are conservative in that many of the boiler startups will actually be warm or hot starts of shorter duration and fewer emissions. For the purposes of the potential emissions calculations, it has been assumed that up to 48 hours of annual boiler operation will be during startup periods. Emissions during shutdown periods have been aggregated with emissions during normal operation for the purpose of determing the total maximum potential annual emissions of the Facility.

The Facility will conduct emissions testing to determine the actual emissions from the biomass boiler during startup and shutdown periods.

(i)(b)(2) Other Stationary Source Emissions

Cooling Tower PM_{10}

Wet cooling towers provide direct contact between the cooling water and the air stream being drawn through the tower. A portion of the cooling water can be entrained in the air stream. The water droplets entrained in the air stream is classified as drift, which results in particulate emissions from the solids contained in the droplets as the water evaporates. The quantity of the drift and resulting particulate emissions are primarily determined by the design and operation of the cooling tower.

The formation of drift and the resulting particulate emissions will be minimized by controlling the dissolved solids content of the recirculating water and controlling water droplet drift.

Drift eliminators are designed to remove the water droplets from the air stream before it exits the tower. The exhaust system of the Facility cooling tower will be equipped with mesh drift eliminators that will control entrained water droplets to less than 0.0005% of the recirculating water flow and minimize particulate emissions to maximum extent achievable for a wet cooling tower.

Diesel Fire Pump

The Facility will also include a 323 horsepower diesel fire pump. The diesel fire pump will be fired with ULSD fuel to minimize SO_2 and PM emissions and will be certified to meet the applicable EPA Tier 2 emission standards for diesel engines. The diesel fire pump will be limited to 300 hours of operation per year, and other than one hour per day for maintenance and testing, will not be operated concurrently with the biomass boiler.

Deleted: Emergency Generator¶
The Facility will include a 500 kW emergency diesel generator set. The emergency generator will be fired with ULSD fuel to minimize SO_2 and PM emissions and will be certified to meet the applicable EPA Tier 2 emission standards for diesel engines. The emergency generator will be limited to 300 hours of operation per year, and other than one hour per day for maintenance and testing, will not be operated concurrently with the biomass boiler. ¶

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(i)(b)(3) Fugitive Emissions

Fugitive dust emissions potentially resulting from truck traffic on Site roadways and from wood fuel storage and handling operations will be minimized through a number of Best Management Practices and equipment designs. These measures will include the use of paved roadways, regular sweeping of roadways, wetting of fuel storage piles as needed of 15 parts per million (0.0015 percent by weight), the Facility will comply with the state distillate oil fuel sulfur content standard.

Fuel Burning Devices

NHCAR Chapter Env-A 2000 establishes emission standards for particulate matter and visible emissions from stationary fuel burning devices. A certified COMS will be installed on the boiler exhaust stack to monitor and continuously record compliance with the state opacity limits. The maximum particulate emission rate from the biomass boiler will comply with the state particulate matter emission standard. Periodic emissions testing will be conducted to demonstrate compliance with the state particulate matter standard.

As the diesel fire pump will have a maximum heat input rating less than 100 MMBtu/hr, and will be installed after January 1, 1985, it will be subject to a particulate matter emission limit of 0.30 lb/MMBtu. The unit will be certified by their manufacturer to meet this standard.

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NO_X Budget Trading Program

NHCAR Chapter Env-A 3200 implements the NO_X Budget Program, which requires reductions in ozone season NO_X emissions from budget sources to achieve the NAAQS for ozone. The biomass boiler at the Facility will utilize wood fuel for the generation of electricity. As the NO_X budget requirements apply only to fossil fuel fired sources, and the Facility is not subject to the requirements of the NO_X Budget Program.

Carbon Dioxide (CO_2) Budget Trading Program

NHCAR Chapter Env-A 4600 establishes the NH State CO_2 Budget Trading Program, which is designed to stabilize, and then reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in the state, in an economically efficient manner. This program does not apply to generating facilities that utilize renewable fuels as they are generally accepted to be greenhouse gas neutral.

(I)(c)(3) Federal Emissions Control Requirements

New Source Performance Standards

Federal NSPS "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" (Subpart Db), apply to steam generating units that are capable of combusting more the 100 MMBtu/hr heat input of fuel, and for which construction, modification, or reconstruction is commenced after June 19, 1984. The biomass boiler at the Facility is subject to these requirements.

The facility's particulate emissions will be well below the regulatory limit of 0.10 lb/MMBtu heat input established in the NSPS regulations. The Facility will similarly comply with the opacity limits in the regulations which require that emissions must not exhibit greater than 20 percent opacity (on a 6-minute average basis), except for one 6-minute period per hour of no source category, or the most stringent emissions limitation which is achieved in practice for a source category. LAER may be achieved by a combination of a change in the raw material processes, a process modification, and/or add-on emission controls.

Detailed BACT/LAER analyses are included as part of the Facility Air Permit Application, which is included in Appendix C.

The MACT emission limitation for a new source is defined as the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority determines is achievable. The detailed MACT determinations are included as part of the Facility Air Permit Application, which is included in Appendix C.

(i)(e) Air Quality Impact Analysis

An air quality impact analysis was performed using the EPA and NHDES approved dispersion models, to demonstrate that the combined emissions from the Facility will result in air quality impacts that are below established NAAQS and allowable incremental increases. The modeled impacts from the Facility were added to representative, regional background values to demonstrate compliance with the NAAQS and NH AAQS.

The maximum modeled air quality impacts from the Facility are summarized on Table (h)(3)(i)-4. As shown on Table (h)(3)(i)-4, the impacts from the Facility, combined with existing background concentrations, will not cause or contribute to an exceedance of NAAQS. The Facility will also have maximum impacts that are less than the Significant Impact Levels ("SILs") in Class II areas for all pollutants, thus demonstrating compliance with the respective PSD increments.

A complete description of the air dispersion modeling analysis is provided as part of the Facility Air Permit Application, which is included in Appendix C.

(i)(f) Additional Impact Analyses

The PSD regulations require sources to analyze potential impacts that may occur as a result of the proposed source and general commercial, residential, industrial, and other growth associated with the source. There are also additional PSD requirements for sources impacting designated Class I areas such as the Dry River and Great Gulf Wilderness area that are located in the White Mountain National Forest, approximately 20 kilometers or more south of the Project Site.

Although the maximum NO_2, SO_2 and $PM_{2.5}$ impacts from the Facility in Class I areas exceed their respective SILs, the impact levels are well below established PSD increment thresholds and result in minor increases to background air quality that doe not cause exceedance of NAAQS. LBB has conducted additional cumulative modeling analyses to confirm that the impacts from the Facility, when combined with the impacts from any other applicable

Deleted: is currently working with NH DES and the Federal Land Manager to complete additional originally installed in 1966 and refurbished in 1993. A bubbling fluidized bed (BFB), which represents highly efficient and advanced biomass combustion and power conversion technology, will be installed at the base of the boiler in place of the existing black liquor firing and recovery systems. A new fabric filter ("baghouse") system will be installed to control particulate emissions and a new selective catalytic reduction (SCR) system will be added to control NO_X emissions. A dry sorbent injection system will also be installed to assure compliance with the specified sulfur dioxide emission limitation. The boiler and emissions control systems will be enclosed within a building (the "boiler building"), which will minimize noise impacts in the surrounding community and provide an aesthetically appropriate exterior finish, similar to a large commercial building.

Development of the overall Facility will also include construction of a new turbine building adjacent to the boiler building, which will house the steam turbine generator. A new cooling tower will be installed near the western edge of the property behind the boiler building. Two wood fuel off-loading and storage areas will be developed. Each wood handling and storage area will be paved and systems will be installed to properly manage stormwater. The fuel handling and storage area closest to the boiler will serve as the main fuel yard. Trucks delivering wood fuel to this area will be off loaded using three tilting truck dumpers. A rail siding that previously existed on the Site will also be re-constructed to allow for deliveries of wood fuel to the Site. The wood yard on the north east portion of the Site will be equipped with a single tilting truck dumper to accommodate delivery of wood chips, along with equipment to off-load whole logs. Equipment will be installed within a new building in this area to produce wood chips from whole logs. Chips produced in this area, along with those delivered directly to the main fuel yard will be mechanically conveyed to a wood processing building to assure uniform wood chip size. From the wood processing building, the chips will be conveyed into the boiler or returned to one of the storage piles adjacent to the boiler building in the main fuel yard.

An electric transmission interconnection line will be installed between the site and the existing high voltage transmission line operated by Public Service Company of New Hampshire (PSNH). A small switchyard will be installed adjacent to the turbine building, which will provide necessary power isolation systems and a step up transformer to increase the voltage of the power produced by the steam turbine generator to 115 kVA, consistent with the PSNH transmission line. From the switchyard, an underground transmission cable will be installed along the route of an existing underground pipe formerly used to transport pulp from the site to the Fraser Gorham paper mill. The underground pipe exits the Site near the intersection of Coos and Community Streets and generally follows the route of the former rail line from the Site to Shelby Street and Devent Street. The transmission cable will transition to an overhead line approximately 0.75 miles south of the Site and 0.1 miles northwest of the existing PSNH East Side substation. The overhead transmission line will be installed within the existing cleared corridor between Devent Street and the PSNH substation.

In early December 2009, Laidlaw received the final version of an interconnection feasibility study (see body of the report provided in Appendix Q) from the Independent System Operator of the New England ("ISO-NE") transmission system the entity charged with oversight over the local transmission system. The results indicate that Laidlaw's project will be able to connect to the transmission system with upgrades estimated to be less than $1 million. The Study takes into account all existing facilities

Pollutants ("HAPs") will meet levels deemed Maximum Achievable Control Technology ("MACT") for wood fueled boilers.

A new fabric filter ("baghouse") system will be installed to achieve a particulate emission rate less than 0.010 pounds per million Btu of heat input to the boiler ("lbs/MMBtu"). This emission rate is approximately one-half of the applicable regulatory limit. A new SCR system will be installed following the ESP to control emissions of NO_X to no more than 0.060 lbs/MMBtu, a level previously deemed as LAER by the New Hampshire Department of Environmental Services, Air Resources Division ("ARD"). Sulfur dioxide emissions will be minimized to less than 0.012 lbs/MMBtu based on the inherently low sulfur content of wood, and use of a dry sorbent injection system as needed to maintain compliance with the emission limit. Emissions of carbon monoxide ("CO") and volatile organic compounds ("VOC") that typically result from incomplete fuel combustion will be minimized by the advanced and highly efficient BFB combustion technology that will be installed in the boiler. Emissions of sulfur compounds and trace metals will be minimized by the inherently clean composition of the wood fuel.

The ambient air quality impacts resulting from the boiler and the emissions control technologies summarized above have been evaluated using computer dispersion models approved by the US EPA and NH DES. The impacts to air quality are well below the levels established in the National Ambient Air Quality Standards ("NAAQS"), which have been developed to be protective of human health and the environment, including a margin of safety, for even the most sensitive of the population.

The Project will be subject to stringent ongoing performance testing, monitoring, recordkeeping and reporting to both NHDES and US EPA over its operating life to assure that the actual emissions from the Facility meet the proposed limits.

Noise

The Project has been designed with advanced equipment and added noise suppression measures to assure that the Project will not exceed the selected reference criteria for impacts in the surrounding community which mirror the level contained in the City of Berlin's noise performance standards. The primary sources of noise will be the boiler, ancillary plant equipment (fans, pumps, etc.), the cooling tower, wood unloading equipment, wood processing equipment (chippers and screen), an electric transformer, and mobile equipment such as fuel delivery trucks, front end loaders, and other equipment handling wood in the two wood yards. The boiler, its major supporting equipment, and the wood processing equipment will be located within buildings and/or in enclosures designed to reduce sound transmittance. Barrier walls will be installed near the cooling tower to reduce cooling tower sound levels at the nearby property line. A barrier wall will similarly be installed in the switchyard area to reduce off site noise impacts

[6] BACT applies to those criteria pollutants for which the ambient air quality meets National Ambient Air Quality Standards. LAER applies to any criteria pollutants for which the ambient air quality exceeds NAAQS. In the case of the proposed Project, LAER

When the transformers arrive on site, they will be installed, and an initial backfeed to the main transformer will be performed. As the equipment installation and final connections of piping and wiring is nearing completion, the process of checking the electrical and control systems, starting up major equipment, cleaning pipelines, and testing all systems will begin.

When the "cold" commissioning process described above is complete, "hot" commissioning will begin with the first fire of the boiler. All of the safety systems of the plant will be thoroughly tested and confirmed. The plant will then undergo emissions testing and performance testing, confirming that all guarantees and specifications have been met. With the completion of the final performance run and acceptance by the equipment manufacturer and owner, the plant will be declared ready for commercial operation.

(g) ASSOCIATED TRANSMISSION LINE INFORMATION

(1) Location shown on U.S. Geological Survey Map

The regional transmission line with which the Facility will interconnect is shown in Figure (g)(1)-1. The route of the Project's electric transmission interconnection is shown in Figures (g)(1)-2. The route and transmission interconnection system is described below.

(2) Corridor width for:

a. New route

The transmission line from the Site will be a new 115kV cable installed within a trench along the route of an existing underground 18-inch diameter fiberglass reinforced pipe formerly used to transport pulp from the Pulp Mill to Fraser's Paper Mill in Gorham. The underground pipe leaves the Site near the intersection of Coos and Community Streets and generally follows the route of the former rail bed from the south end of the Site to the north end of Shelby Street. The pipe follows Shelby Street and Devent Street along a right-of-way that is currently under easement control of LBB. The cable will transition to overhead conductors at the east side of Devent Street to the existing PSNH East Side Substation 300. The overhead conductors will run on one or two new steel monopole towers along with the existing Smith Hydro Z177 Line to the substation a distance of approximately 800 feet including elevation change.

b. Widening along existing route

The existing underground system will not require widening. There will be a pulling manhole installed at the Site and at least two more pulling manholes along the existing effluent pipe right-of-way. These manholes will be temporary and backfilled upon completion of the cable installation. There may be some clearing south of the existing Z177 line from Smith Hydro from Devent Street up the hill to the PSNH substation.

(3) Length of line

The length of the underground portion of the transmission line off from the Project Site is estimated at 3,200 feet and the portion above ground at 800 feet.

(4) Distance along new route

The distance along the new route is the underground portion of 3,200 feet.

(5) Distance along existing route

The distance along the existing route is the 800-foot long portion of the line that will be installed above ground from Devent Street to the substation. The overhead line will follow a cleared transmission corridor that includes several other existing overhead lines.

(6) Voltage (design rating)

The system is designed for 115 kV nominal.

(7) Any associated new generating unit or units

Same as application information (f) above.

(8) Type of construction (described in detail)

The 115 kV cable will be XLPE insulated single conductor installed within a trench that conforms to all applicable codes and PSNH requirements. The overhead line construction will have a transition tower from underground to overhead. The conductor will be 477 kcmil ACSR and extend to a dual circuit steel monopole that will carry this conductor and the existing Smith Hydro Z177 line on the same structure into the PSNH East Side Substation 300.

(9) Construction schedule, including start date and scheduled completion date

The construction period for the electric transmission interconnection is expected to be six months. The facilities would need to be completed in time to "backfeed" power to the facility for startup and testing. It is estimated that the work would start in August 2011 and be completed by February 2012.

(10) Impact on system stability and reliability

Please refer to section (f)(3)(e) above.

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[10] This fuel moisture content has been established as the design point for equipment supplier performance guarantee purposes.

manual reclaiming of fuel from the unprocessed fuel storage area. Each hopper will discharge to a common 250 ton per hour unprocessed fuel out-feed conveyer, which will supply the fuel processing system.

A magnet will be installed over the truck dumper outfeed conveyer near the processing building. A disc screen capable of processing 250 tons per hour will be used to screen the unprocessed wood for boiler fuel. Two wood hogs will be used to reduce the wood fuel from the disc screen to a three inch minus size. Each hog will be capable of processing up to 75 tons per hour of wood fuel.

A 250 ton per hour stockout conveyer will receive the discharge from the processing building and convey it to the processed wood fuel storage area. The processed wood fuel storage area will be open and on paved ground with an under drain system to remove rain water from the storage area. The paved pile area will have a perimeter drain system.

Three 50 ton per hour mechanical reclaim hoppers located under the storage area will supply a single boiler feed conveyer. The boiler feed conveyer will feed the shuttle conveyers which will distribute fuel to individual boiler chutes. A single return conveyer will return excess fuel to the wood storage area. Each fuel metering bin will be equipped with screw feeders to meter wood fuel to the boiler feed chutes. There will be one inverted cone type chute connecting each pneumatic distributor on the boiler with a set of feeders at the metering bin.

(iii) Ash Handling Systems

The ash handling facilities will consist of separate collection and storage systems for fly ash, and for bed sand removal, screening and re-injection.

Fly ash will be continuously collected from the baghouse using a dry mechanical system. Collected fly ash will be conveyed to a dry storage bin inside of the boiler building. The storage capacity will be sufficient to accept a minimum of twenty four hours of full-load operation. There will be an atmospheric vent on the ash silo equipped with a filter to minimize fugitive emissions. Ash from the elevated storage bin will be processed through a pug mill which mixes dry fly ash with water to produce a wet cake that minimizes dust generation during subsequent handling. The wetted fly ash will then be loaded onto trucks and transported off site for disposal or for beneficial re-use in agricultural land applications. LBB has confirmed that the ash can accepted and disposed at the nearby Mount Carberry landfill if not acceptable for beneficial re-use and until such time as adequate ash analytical data is available to file an application with DES for re-use of the material.

Bottom ash is virtually non-existent in a fluid bed boiler. Fuel is continually recirculated within the fluidized bed until fully combusted. A small stream of sand from the bed is continually withdrawn, screened and returned to the boiler, along with additional make-up sand as required. A small amount of noncombustible material such as rock, slag, glass or metal, is screened out of the bed material and collected for periodic disposal. The sand silo

The primary source of water for fire protection will also be City water. A diesel engine-driven fire pump will be used as a backup system. The entire wood storage area and power block will be served by an underground hydrant system. A wet standpipe system will be installed in all heated buildings. Unheated buildings and wood conveyers will be served by a dry standpipe with sprinklers. Portable hand extinguishers will be located throughout the Facility. Office areas will be equipped with wet pipe sprinkler systems. The steam turbine generator, lube oil tank area and the main transformer will be served with a fire protection system that will meet applicable codes and the requirements of the local Fire Chief. All fire detection and alarm systems will be installed to meet their respective codes and the requirements of the local Fire Chief.

(v) Air Pollution Control Systems

The BFB technology used in the Project's combustion system represents a highly efficient system for biomass fuel conversion and results in low levels of combustion emissions. Through good combustion efficiency, the BFB technology generates low emissions of pollutants resulting from incomplete combustion such as CO and VOC. The combustion system also incorporates FGR, a technology that helps to control combustion temperatures and therefore reduces the formation of NO_X.

In addition to the inherently low emitting technology associated with the combustion system, the Project will incorporate a number of additional systems that represent Best Available Control Technology and Lowest Achievable Emission Rate technology to further minimize air emissions.

A new fabric filter ("baghouse") system will be installed to maximize control of particulate emissions and meet the BACT emission limits. The baghouse will provide greater than 99% control of particulate.

An SCR system will be installed to minimize NO_X emissions. The SCR system will utilize aqueous ammonia (NH_3) that will be injected into the flue gas in a stoichiometric ratio proportional to the mass of NO_X to be removed. The flue gas and NH_3 will pass through a catalyst bed where NO_X in the flue gas will be converted into diatomic nitrogen and water. An ammonia injection control system will be installed to accurately inject the needed amount of ammonia into the flue gas stream upstream of the catalyst to provide optimal conditions for the control and minimization of both NO_X and NH_3 and assure compliance with permit limits. The dilute liquid NH_3 for the SCR system will be stored on-site in a 19% aqueous solution in a 10,000 gallon storage tank equipped with secondary containment. The tank will provide sufficient storage for up to ten days of boiler operation, requiring only a single tanker truck delivery per week. The NH_3 storage tank will include an unloading system to accept deliveries by truck.

A new dry sorbent injection system will be installed that will introduce limestone or a similar agent into the boiler flue gas path at the appropriate temperature to effectively control emissions of sulfur dioxide.

70% of NO_X emissions formed within the boiler. The SCR system will inject vaporized aqueous NH_3 into the hot exhaust gas path which will react with the NOx in the exhaust gas to form nitrogen and water vapor as the exhaust gases pass through the catalyst beds. The use of the BFB technology, clean wood fuel, good combustion practices, and SCR will result in a NO_X emission rate from the biomass boiler no greater than 0.060 lb/MMBtu of heat input based on a 30-day rolling average during normal operation.

Carbon Monoxide

CO emissions are associated with incomplete combustion of fuel in a boiler. These emissions will be minimized by utilizing the highly efficient BFB combustion technology. The wood fuel will be combusted in a heated bed of sand-like material which is fluidized within a rising column of air. The hot bed material effectively liberates the carbon in the wood fuel, which allows the oxygen (O_2) in the combustion air to more freely react with the fuel, resulting in an efficient combustion process. The air to fuel ratio and combustion temperature in the boiler will be optimized and monitored to achieve the desired balance between CO and NO_X emissions. As mentioned earlier, the Facility also will utilize a fuel preparation system that will help optimize the quality, size and moisture content to promote efficient combustion, which will also help mitigate CO formation. The use of BFB combustion technology in the boiler design, good combustion practices, and fuel type will result in a CO emission rate from the biomass boiler no greater than 0.075 lb/MMBtu of heat input based on a 24-hour daily block average during normal operation.

Sulfur Dioxide/Sulfuric Acid Mist

Emissions of sulfur compounds result from oxidation of sulfur contained in a fuel. The Facility will utilize wood fuel which has an inherently low sulfur content, in combination with a dry sorbent injection system on an as-needed basis, to maintain SO_2 no greater than 0.012 lb/MMBtu of heat input during normal operation. The characteristics of wood fly ash also serve to capture much of the sulfur compounds and further minimize emissions. Based on experience with other generating facilities using an SCR control system, no more 10% of the SO_2 generated in the boiler is expected to be further oxidized to SO_3 and combine with water vapor in the flue gas to produce sulfuric acid mist (H_2SO_4). The resulting H_2SO_4 emission rate is expected to be less than 0.002 lbs/MMBtu of heat input.

Particulate Matter

Particulate matter is generated in a boiler by incomplete combustion and the non-combustible fraction of a fuel. The BFB combustion technology and operating controls provide a greater degree of complete combustion than most other wood fired boiler designs. The boiler's fabric filter baghouse will abate over 99 percent of the particulate emissions formed in the boiler. These measures will result in a filterable $PM/PM_{10}/PM_{2.5}$ emission rate no greater than 0.010 lb/MMBtu of heat input during normal operation.

The potential emissions during startup periods have been estimated on Table (h)(3)(i)-3. These boiler startup emissions estimates are conservatively based on a total of 4 cold starts per year of the biomass boiler. These estimates are conservative in that many of the boiler startups will actually be warm or hot starts of shorter duration and fewer emissions. For the purposes of the potential emissions calculations, it has been assumed that up to 48 hours of annual boiler operation will be during startup periods. Emissions during shutdown periods have been aggregated with emissions during normal operation for the purpose of determing the total maximum potential annual emissions of the Facility.

The Facility will conduct emissions testing to determine the actual emissions from the biomass boiler during startup and shutdown periods.

(i)(b)(2) Other Stationary Source Emissions

Cooling Tower PM_{10}

Wet cooling towers provide direct contact between the cooling water and the air stream being drawn through the tower. A portion of the cooling water can be entrained in the air stream. The water droplets entrained in the air stream is classified as drift, which results in particulate emissions from the solids contained in the droplets as the water evaporates. The quantity of the drift and resulting particulate emissions are primarily determined by the design and operation of the cooling tower.

The formation of drift and the resulting particulate emissions will be minimized by controlling the dissolved solids content of the recirculating water and controlling water droplet drift.

Drift eliminators are designed to remove the water droplets from the air stream before it exits the tower. The exhaust system of the Facility cooling tower will be equipped with mesh drift eliminators that will control entrained water droplets to less than 0.0005% of the recirculating water flow and minimize particulate emissions to maximum extent achievable for a wet cooling tower.

Diesel Fire Pump

The Facility will also include a 323 horsepower diesel fire pump. The diesel fire pump will be fired with ULSD fuel to minimize SO_2 and PM emissions and will be certified to meet the applicable EPA Tier 2 emission standards for diesel engines. The diesel fire pump will be limited to 300 hours of operation per year, and other than one hour per day for maintenance and testing, will not be operated concurrently with the biomass boiler.

(i)(b)(3) Fugitive Emissions

Fugitive dust emissions potentially resulting from truck traffic on Site roadways and from wood fuel storage and handling operations will be minimized through a number of Best Management Practices and equipment designs. These measures will include the use of paved roadways, regular sweeping of roadways, wetting of fuel storage piles as needed of 15 parts per million (0.0015 percent by weight), the Facility will comply with the state distillate oil fuel sulfur content standard.

Fuel Burning Devices

NHCAR Chapter Env-A 2000 establishes emission standards for particulate matter and visible emissions from stationary fuel burning devices. A certified COMS will be installed on the boiler exhaust stack to monitor and continuously record compliance with the state opacity limits. The maximum particulate emission rate from the biomass boiler will comply with the state particulate matter emission standard. Periodic emissions testing will be conducted to demonstrate compliance with the state particulate matter standard.

As the diesel fire pump will have a maximum heat input rating less than 100 MMBtu/hr, and will be installed after January 1, 1985, it will be subject to a particulate matter emission limit of 0.30 lb/MMBtu. The unit will be certified by their manufacturer to meet this standard.

NO_X Budget Trading Program

NHCAR Chapter Env-A 3200 implements the NO_X Budget Program, which requires reductions in ozone season NO_X emissions from budget sources to achieve the NAAQS for ozone. The biomass boiler at the Facility will utilize wood fuel for the generation of electricity. As the NO_X budget requirements apply only to fossil fuel fired sources, and the Facility is not subject to the requirements of the NO_X Budget Program.

Carbon Dioxide (CO_2) Budget Trading Program

NHCAR Chapter Env-A 4600 establishes the NH State CO_2 Budget Trading Program, which is designed to stabilize, and then reduce anthropogenic emissions of CO_2, a greenhouse gas, from CO_2 budget sources in the state, in an economically efficient manner. This program does not apply to generating facilities that utilize renewable fuels as they are generally accepted to be greenhouse gas neutral.

(i)(c)(3) Federal Emissions Control Requirements

New Source Performance Standards

Federal NSPS "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" (Subpart Db), apply to steam generating units that are capable of combusting more the 100 MMBtu/hr heat input of fuel, and for which construction, modification, or reconstruction is commenced after June 19, 1984. The biomass boiler at the Facility is subject to these requirements.

The facility's particulate emissions will be well below the regulatory limit of 0.10 lb/MMBtu heat input established in the NSPS regulations. The Facility will similarly comply with the opacity limits in the regulations which require that emissions must not exhibit greater than 20 percent opacity (on a 6-minute average basis), except for one 6-minute period per hour of no source category, or the most stringent emissions limitation which is achieved in practice for a source category. LAER may be achieved by a combination of a change in the raw material processes, a process modification, and/or add-on emission controls.

Detailed BACT/LAER analyses are included as part of the Facility Air Permit Application, which is included in Appendix C.

The MACT emission limitation for a new source is defined as the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority determines is achievable. The detailed MACT determinations are included as part of the Facility Air Permit Application, which is included in Appendix C.

(i)(e) Air Quality Impact Analysis

An air quality impact analysis was performed using the EPA and NHDES approved dispersion models, to demonstrate that the combined emissions from the Facility will result in air quality impacts that are below established NAAQS and allowable incremental increases. The modeled impacts from the Facility were added to representative, regional background values to demonstrate compliance with the NAAQS and NH AAQS.

The maximum modeled air quality impacts from the Facility are summarized on Table (h)(3)(i)-4. As shown on Table (h)(3)(i)-4, the impacts from the Facility, combined with existing background concentrations, will not cause or contribute to an exceedance of NAAQS. The Facility will also have maximum impacts that are less than the Significant Impact Levels ("SILs") in Class II areas for all pollutants, thus demonstrating compliance with the respective PSD increments.

A complete description of the air dispersion modeling analysis is provided as part of the Facility Air Permit Application, which is included in Appendix C.

(i)(f) Additional Impact Analyses

The PSD regulations require sources to analyze potential impacts that may occur as a result of the proposed source and general commercial, residential, industrial, and other growth associated with the source. There are also additional PSD requirements for sources impacting designated Class I areas such as the Dry River and Great Gulf Wilderness area that are located in the White Mountain National Forest, approximately 20 kilometers or more south of the Project Site.

Although the maximum NO_2, SO_2 and $PM_{2.5}$ impacts from the Facility in Class I areas exceed their respective SILs, the impact levels are well below established PSD increment thresholds and result in minor increases to background air quality that doe not cause exceedance of NAAQS. LBB has conducted additional cumulative modeling analyses to confirm that the impacts from the Facility, when combined with the impacts from any other applicable

Table (h)(3)(i)-2
Maximum Stack Concentrations & Emission Rates
Berlin BioPower - Berlin, New Hampshire

Pollutant	Biomass Boiler Normal Operation			Emergency Generator	Fire Pump	Cooling Tower
	Wood Fuel			Diesel	Diesel	
	ppm@7%O_2	lb/MMBtu	lb/hr	lb/hr	lb/hr	lb/hr
NO_x	36.0	0.060	66.9	8.5	2.3	
CO	74.0	0.075	83.6	0.59	0.28	
SO_2	5.0	0.012	13.4	0.0071	0.0028	
H_2SO_4		0.002	2.2			
PM (filterable)		0.010	11.1	0.027	0.037	0.30
PM_{10} (filterable)		0.010	11.1	0.027	0.037	0.30
$PM_{2.5}$ (filterable)		0.010	11.1	0.027	0.037	0.30
NH_3	20.0	0.012	13.4			
VOC	17.0	0.010	11.1	0.015	0.055	
Formaldehyde		0.0044	4.9	0.0056	0.0022	
Hydrogen Chloride		0.00083	0.92			
Lead		0.000048	0.1			
Mercury		0.0000030	0.0			

(1) The biomass boiler maximum stack concentrations and emission rates during normal operation do not apply at less than 70% of maximum load.
(2) The maximum lb/hr emission rates for the boiler are derived from the lb/MMBtu emission rate, the maximum heat input rate (1,013 MMBtu/hr), and a factor of 10% to account for expected variability in the exhaust gas volumetric flow rate from the boiler.

Table (h)(3)(i) - 3
Facility Potential Emissions Summary
Berlin BioPower - Berlin, New Hampshire

Pollutant	Potential Total Emissions (tons per year)						
	Biomass Boiler	Fire Pump	Cooling Tower	PTE - Normal Operation(1)	Boiler Startup(2)	Fugitive Emissions(3)	Facility PTE(4)
Maximum Hours of Operation per Year	8,688	300	8,760	8,688	72	8,760	
NO_x	242.9	0.2	0.0	243.2	1.6	0.0	244.7
CO	303.6	0.2	0.0	303.8	3.7	0.0	307.5
SO_2	48.6	0.0	0.0	48.6	0.1	0.0	48.6
H_2SO_4	7.4	0.0	0.0	7.4	0.0	0.0	7.4
PM (filterable)	40.5	0.0	1.3	41.8	0.4	1.1	43.3
PM_{10} (filterable)	40.5	0.0	1.3	41.8	0.4	0.5	42.7
$PM_{2.5}$ (filterable)	40.5	0.0	1.3	41.8	0.4	0.1	42.3
CO_2	894,864	51	0	894,915	1,924	0	896,839
NH_3	49.5	0.0	0.0	49.5	0.0	0.0	49.5
VOC	40.5	0.0	0.0	40.5	0.1	0.0	40.6
Formaldehyde	17.8	0.0	0.0	17.8	0.0	0.0	17.8
Hydrogen Chloride	3.4	0.0	0.0	3.4	0.0	0.0	3.4
Lead	0.2	0.0	0.0	0.2	0.0	0.0	0.2
Mercury	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total HAPS	65.0	0.0	0.0	65.0	0.1	0.0	65.1

(1) Total emissions represent maximum potential of all equipment operating independently in normal operation. The biomass boiler emissions are based on 932 MMBtu/hr average heat input. As all equipment will not run for maximum potential hours shown, actual emissions will be less.

(2) Boiler startup emissions have been estimated assuming a total of 6 cold startups per year. Emissions during shutdown periods are aggregated with emissions during normal boiler operation.

(3) Fugitive emissions resulting from wood fuel storage and handling activities.

(4) The Facility PTE is the sum of the PTE of all sources during normal operation, emissions during startup and shutdown of the Biomass Boiler, and fugitive emissions.

Table (h)(3)(l)-4
Summary of Maximum Air Quality Impacts - Criteria Pollutants

Pollutant	Averaging Period	National Ambient Air Quality Standard (µg/m³)	New Hampshire Ambient Air Quality Standard (µg/m³)	Significant Impact Level(2)		Maximum Modeled Impact(1)		Background Ambient Concentration(3) (µg/m³)	Total Impact Concentration(4)	
				(µg/m³)	% of NAAQS	(µg/m³)	% of SIL		(µg/m³)	% of AAQS
NO_2	Annual	100	100	1	1%	0.6	60%	15	16	16%
CO	8-hour	10,000	10,000	500	5%	28	6%	4,000	4,028	40%
	1-hour	40,000	40,000	2,000	5%	117	6%	9,000	9,117	23%
SO_2	Annual	80	80	1	1%	0.1	10%	16	16	20%
	24-hour	365	365	5	1%	1.1	22%	39	40	11%
	3-hour	1,300	1,300	25	2%	4.7	19%	79	84	6%
PM_{10}	Annual	No Standard	50	1	NA	0.1	10%	16	16	32%
	24-hour	150	150	5	3%	1.4	28%	30	31	21%
$PM_{2.5}$	Annual	15	15	0.3	2%	0.1	33%	9.0	9.1	61%
	24-hour	35	65	2.0	6%	1.4	70%	21	22	64%

(1) Maximum Modeled Impact is the maximum impactin a Class II area determined by dispersion modeling for each pollutant averaging period, considering the emissions from all project emissions sources.
(2) Significant Impact Levels are defined in EPA's Prevention of Significant Deterioration (PSD) Regulations for all pollutants expect $PM_{2.5}$. Although not yet promulgated by EPA or NHDES through rulemaking, NHDES has adopted a draft policy of applying the PM2.5 SILs recommended by the Northeast States for Coordinated Air Use Management (NESCAUM).
(3) Background Ambient Concentrations provided by NHDES
(4) Total Impact Concentration is the sum of the Maximum Modeled Impact and the Background Ambient Concentrations, and is used to determine AAQS compliance.