The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

May 28, 2010

Louis T. Bravakis, Vice President
Laidlaw Berlin BioPower, LLC
45 State Street
Montpelier, VT 05602

Re: Draft Temporary/NSR/PSD Air Permit
70 Megawatt Biomass-fired Electric Generating Facility
Laidlaw Berlin BioPower, LLC
57 Hutchins Street, Berlin, NH
Facility Identification #: 3300790137, Application # 09-0285

Dear Mr. Bravakis:

The New Hampshire Department of Environmental Services, Air Resources Division (DES) has prepared a draft permit for the proposed biomass-fired electric generating facility in Berlin, New Hampshire. The draft permit, Preliminary Determination and modeling memorandum are enclosed for your review. A public notice inviting comments on the draft permit and supporting documents will be published in the New Hampshire Union Leader and the Berlin Daily Sun.

Device	Application Date	Notice Date	Public Hearing	Close of Comment Period
70 Megawatt Biomass-fired Electric Generating Facility	December 16, 2009	May 28, 2010	July 1, 2010	July 2, 2010

In accordance with the permitting and public notice requirements of the Non-Attainment New Source Review and Prevention of Significant Deterioration programs, and New Hampshire Code of Administrative Rules Env-A 621.05, *Notification to EPA*, copies of the public notice, draft permit, and supporting documents are being provided to:

- The United States Environmental Protection Agency (USEPA)
- The Office of the Federal Land Manager
- The City of Berlin
- The North Country Council, Inc.

We are also forwarding a copy to the Town of Gorham and the New Hampshire Site Evaluation Committee for their review.

Please note that a public hearing has been scheduled for 6:00 p.m. on Thursday July 1, 2010 in the auditorium in Berlin City Hall. Details regarding the comment process an public hearing are described in the enclosed public notice. Comments must be received by DES by the close of the comment period. If you have any questions regarding this draft permit, please contact me at (603) 271-6798 or via email at todd.moore@des.nh.gov.

Sincerely

COPY

Todd A. Moore
Construction & Planning Manager
Air Resources Division

By certified mail #7007 3150 0004 7246 6382

Enc. Draft Temporary/NSR/PSD Air Permit
Preliminary Determination
Modeling Memorandum
Public Notice

Cc: Donald Dahl, USEPA
Ralph Perron, USFS
Debra Patrick, City Clerk - City of Berlin
Michael King, Executive Director – North Country Council, Inc.
Grace LaPierre, Town Clerk - Town of Gorham
Thomas S. Burack, Chairman - NH Site Evaluation Committee
Dammon Frecker, ESS Group, Inc.

PRELIMINARY DETERMINATION

To Grant a

Prevention of Significant Deterioration/Non-Attainment New Source Review Permit

For

Laidlaw Berlin BioPower, LLC

To construct

1,013 MMBtu/hr Biomass Boiler, 323 hp Diesel Fire pump and 4-cell Cooling Tower

located at

57 Hutchins Street
Berlin, NH 03570

Prepared by the
New Hampshire Department of Environmental Services
Air Resources Division

May 28, 2010

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I. Applicant's Name and Address

Laidlaw Berlin BioPower, LLC

90 John Street, 4th Floor

New York, NY 10038

II. Physical Address of the Proposed Facility

Berlin BioPower

57 Hutchins Street

Berlin, NH 03570

County: Coos

UTM Coordinates: Easting: 326984 m Northing: 4926531 m

III. Background

On December 16, 2009, Laidlaw Berlin BioPower, LLC (LBB) submitted an application for Certificate of Site and Facility to the New Hampshire Energy Facility Site Evaluation Committee (NHSEC). Included in the application to NHSEC, LBB identified the need to obtain a Non-attainment New Source Review (NSR) and Prevention of Significant Deterioration (PSD) permit to construct and operate a 70 megawatt (MW) biomass fired power plant in Berlin, New Hampshire. The air permit application (also known as a Temporary Permit application) included information concerning the biomass boiler, air pollution control equipment and raw material receiving, storage, and transfer equipment for the facility. The New Hampshire Department of Environmental Services, Air Resources Division (DES) deemed the Temporary Permit application administratively complete on January 14, 2010. Copies of the application were transmitted to the City of Berlin and the Town of Gorham on January 21, 2010.

Since that time, DES requested that LBB re-evaluate portions of their proposal and perform additional air quality impact evaluations to support their application. LBB has responded to these requests by submitting a significantly revised air permit application, which was received at DES on May 20, 2010. DES transmitted copies of this revised application to the City of Berlin and the Town of Gorham on May 21, 2010.

DES' permit decisions are based on the information and analysis provided by the applicant and its own technical expertise. The preliminary determination documents the information and analysis DES used to support the NSR and PSD permit decisions. It includes a description of the proposed facility, the applicable NSR and PSD requirements, and an analysis showing how the applicant complied with the requirements.

DES has concluded that LBB's application is complete and provides the necessary information to demonstrate that the proposed project meets both the NSR and PSD regulations. As such, DES is making the December 16, 2009 and May 20, 2010 permit applications part of the official record for this preliminary determination and draft permit. This project is also subject to the State of New Hampshire permitting requirements contained in the New Hampshire Code of Administrative Rules Env-A 100 et seq. The applicable state requirements are contained in the draft permit and discussed later in this preliminary determination.

Under the New Hampshire PSD and NSR Operating Plans, DES is responsible for completing the Preliminary Determination and draft permit, as well as issuance of the final PSD/NSR permit.

Since DES is the issuing authority for the NSR/PSD Permit, any appeals of a final permit should be made to the Air Resources Council in accordance with Env-A 621.10 *Appeals*.

IV. Project Description

Project Description

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 70 MW biomass fueled energy generating facility. The proposed project consists of a biomass boiler, a cooling tower, a 323 horsepower (hp) fire pump and raw material receiving, storage, and transfer equipment for the biomass boiler.

Equipment Description

The biomass[1] boiler is a bubbling fluidized bed (BFB) type boiler with open hopper bottoms for removal of fuel ash, bed sand material and other combustibles. Primary fuel for the facility will be wood fuel, including whole tree chips. 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 boiler will be capable of generating up to 600,000 pounds per hour of steam at 825^{o}F and 850 psig. The maximum heat input rate[2] of the boiler will be 1,013 million British Thermal Units per hour (MMBtu/hr) assuming fuel with a moisture content of 50%. The boiler will also be equipped with four oil fired burners for use during startup only. Each oil burner will have a maximum heat input rate of 60 MMBtu/hr. These auxiliary burners will be fired with ultra low sulfur diesel (ULSD). LBB has also proposed to install a 323 hp fire pump, which will be fired with ULSD. A 50,000 gallon storage tank will be used to store ULSD.

Air pollution control at the facility will include a dry sorbent injection system (as necessary)for the control of sulfur dioxide (SO_2), sulfuric acid mist and hydrochloric acid, a selective catalytic reduction (SCR) system for the control of nitrogen oxides (NOx) and a fabric filter baghouse for the control of particulate matter (PM). LBB will also operate continuous emission monitors (CEMs) to continuously record NOx, carbon monoxide (CO), ammonia slip, oxygen, opacity and certain operational parameters. Ammonia for the SCR system will be stored on-site in 19% aqueous solution in a storage tank equipped with secondary containment.

Ancillary equipment associated with the biomass boiler will include a 4-cell cooling tower and wood & ash handling systems. 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. Water for cooling and process operations will be provided by the Berlin Water Works municipal supply and distribution system.

Equipment will be installed within a new building 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 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.

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[1] "Biomass fuel" is defined in New Hampshire RSA Section 362-F:2, II as follows: Plant-derived fuel including clean and untreated wood such as brush, stumps, lumber ends and trimmings, wood pallets, bark, wood chips or pellets, shavings, sawdust, and slash, agricultural crops, biogas, or liquid biofuels, **but shall exclude** any materials derived in whole or in part from construction and demolition debris.

[2] The heat input rate to the boiler will vary depending on the moisture content of the wood fuel.

V. General Information

A. PSD/NSR Applicability Determinations & Attainment Status

The proposed LBB facility will be located in Coos County, which is classified as an attainment area for CO, SO_2, NOx and PM, including particulate less than 10 microns in diameter (PM_{10}) and particulate less than 2.5 microns in diameter ($PM_{2.5}$), and therefore, a PSD area for these pollutants. The proposed project will also have emissions of CO in excess of the major source threshold of 250 tons per year (tpy) contained in Env-A 619, *Prevention of Significant Deterioration of Air Quality Permit Requirements*. The PSD program requires the implementation of Best Available Control Technology (BACT) for each regulated new source review pollutant with potential emissions above the PSD significance thresholds.

Coos County is designated as an attainment area for ozone. However, the entire state is part of the Northeast Ozone Transport Region (OTR) and is required to implement at a minimum ozone NSR requirements equivalent to the moderate ozone NSR requirements for all parts of the state. Ozone emissions are addressed by regulating its precursor compounds NOx and volatile organic compounds (VOCs). The proposed project will be a major source of NOx emissions, with potential NOx emissions greater than 100 tpy. The proposed project is therefore subject to NSR under Env-A 618, *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Ozone Transport Region*, which requires the implementation of Lowest Achievable Emission Rate (LAER) for NOx emissions.

B. Site Information

The proposed facility will be located on 57 Hutchins Street in Berlin, New Hampshire. The project site is a 62-acre parcel of land that comprises the southern half of the approximately 120 acre site formerly used as a pulp production facility. This pulp mill shut down in 2006, and much of the building infrastructure and equipment were removed. The site is abutted to the northwest by the Androscoggin River and the remaining portion of the former pulp mill parcel on its northeastern edge. Adjacent properties also include a community ball field, Community Street from the western end of the site, and a predominantly residential neighborhood across Coos and Hutchins Street to the south of the site. The northern end of the downtown district of Berlin lies across the river from the southwest end of the site. General commercial and business properties as well as a hydroelectric generating facility are located on the opposite side of the river along the remainder of the site. The Facility is located approximately 18.3 kilometers north of the Great Gulf Wilderness Area, and 26.2 kilometers north of the Dry River Wilderness Area.

C. Operational Information

The proposed facility will be a base loaded electric generating facility with a nominal gross electrical output of 70 MW. LBB will export generated power to the Public Service of New Hampshire (PSNH) 115 kV transmission system. A switchyard will be installed adjacent to the turbine building, which will provide the necessary power isolation systems and a step up transformer to increase the voltage of the power produced by the steam turbine generator to 115kVA, consistent with the PSNH transmission line. From the switchyard, an underground transmission cable will be installed which 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. An overhead transmission line will be installed within the existing cleared corridor between Devent Street and the PSNH substation.

The biomass boiler will not be operated at loads less than 70% of maximum load, except during periods of startup and shutdown.

D. Quantification of Emissions

This project is classified as a new major source under the PSD/NSR programs. In the application, LBB has proposed the following maximum emissions (including emissions resulting from the operation of air pollution control equipment) from the biomass boiler, cooling tower and the fire pump:

Table 1 - Proposed Facility-wide Emissions (tons/yr)					
Pollutant	**Biomass Boiler**	**Cooling Tower**	**323 hp Fire pump**	**Fugitive Emissions[3]**	**Total**
$PM/PM_{10}/PM_{2.5}$	40.9	1.3	0.03	1.1/0.5/0.1	43.3/42.7/42.3
SO_2	48.7	-	0.001	-	48.7
NOx	244.5	-	0.53	-	245
CO	307.3	-	0.465	-	308
VOCs	40.6	-	0.53	-	41.1
Sulfuric acid mist (H_2SO_4)	8.1	-	-	-	8.1
Ammonia	23.3	-	-	-	23.3
Beryllium	0.0045	-	-	-	0.0045
Mercury	0.012	-	-	-	0.012

The above emissions were estimated based upon the following assumptions:

1. The biomass boiler emissions are based on an average annual heat input of 932 MMBtu/hr. The calculations also assume a total of six cold startups per year, each lasting a maximum of 12 hours. Emissions during the shutdown periods are aggregated with emissions during normal boiler operation. Total boiler emissions therefore include emissions during normal operation (i.e., 8,688 hours per year) and emissions during startups (i.e., 72 hours per year)[4];
2. A maximum of 8,760 hours per year of operation for the cooling tower with a circulating flow rate of 60,000 gallons/minute and total dissolved solids (TDS) content of 2,000 parts per million (ppm);
3. A maximum of 500 hours of operation per year for the fire pump;
4. The maximum sulfur content of USLD is 0.0015% by weight; and
5. The BACT/LAER limitations identified in this Preliminary Determination.

[3] Fugitive emissions resulting from wood fuel storage and handling activities.
[4] Please refer to Tables 3.1, 3.2, 7.1a & 7.2 of the permit application for detailed calculations. Emission factors provided by the boiler manufacturer, Babcock & Wilcox were used to estimate emissions during startup periods. Emission standards for fire pump engines listed in Table 4 of 40 CFR 60, Subpart IIII were used to estimate emissions from the 323 hp fire pump.

The following table compares the projected emissions from the project to the appropriate PSD/NSR applicability thresholds:

Table 2 - PSD and NSR Applicability

Pollutant	Projected Project Emissions (tpy)	PSD Major Source Threshold (tpy)	PSD Significance Threshold (tpy)	NSR Major Source Threshold (tpy)	Triggers NSR/PSD?
$PM/PM_{10}/PM_{2.5}$	43.3/42.7/42.3	250	25/15/10	N/A	**PSD**
SO_2	48.7	250	40	N/A	**PSD**
NOx	245	250		100	**NSR**
CO	308	250	100	N/A	**PSD**
VOCs	41.1	N/A	N/A	50	No[5]
Sulfuric acid mist (H_2SO_4)	8.1		7		**PSD**
Lead	0.2		0.6		No
Beryllium	0.0045		0.0004		**PSD**
Mercury	0.012		0.1		No
Vinyl Chloride	0.08		1		No

Based on the above table, the proposed project will have CO emissions in excess of the PSD major source threshold of 250 tpy; LBB is a major source under the PSD program.

When determining PSD applicability, if a source is above the major source threshold (250 tpy in this case) for any single PSD pollutant, any remaining pollutants are compared to the significance thresholds instead of the major source threshold. For example, since this project was already determined to be a major PSD source for one pollutant (CO greater than 250 tpy), PM emissions would be compared to the 25 tpy PSD significance threshold listed in Table 2 above. Since PM emissions exceed the 25 tpy significance threshold, the proposed source is subject to PSD review for PM emissions.

Based on the above table, the emissions of other regulated attainment pollutants, specifically, $PM/PM_{10}/PM_{2.5,}$ SO_2, sulfuric acid mist and beryllium, are in excess of their respective PSD significance modification thresholds. Therefore, the project is subject to PSD review for these pollutants.

As mentioned above, the emissions of NOx from the proposed project are greater than 100 tpy, the major source threshold under the NSR program. Therefore the project is subject to NSR for NOx. Among other regulatory requirements, the source must meet LAER for NOx emissions and must offset its NOx emissions by obtaining emissions credits at a ratio of 1.15 credits for each ton of NOx permitted to be emitted from the facility.

[5] While the proposed VOC increase is above the 40 tpy significant modification threshold, LBB is a minor source of VOCs under the NSR program (VOC emissions are less than 50 tpy) and therefore does not trigger NSR for this project.

VI. Additional State and Federal Regulatory Requirements

A. Federal New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units

The proposed biomass boiler will be subject to the Code of Federal Regulations, 40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* (Subpart Db). Subpart Db affects industrial, commercial, or institutional steam generating units with a design heat input capacity greater than 100 MMBtu/hr and constructed after June 19, 1984. DES is delegated by EPA to enforce Subpart Db as it pertains to industrial, commercial, or institutional steam generating units.

The Subpart Db emission limit for PM is 0.030 lb/MMBtu (40 CFR 60.43b(h)(1)). Subpart Db emission standards for SO_2 and NOx (40 CFR 60.42b(k)(2) & 40 CFR 60.44b(l)(1), respectively) are not applicable to the boiler[6]. However, the boiler is subject to the more stringent PSD/NSR emission limits for these pollutants. Finally, there is an opacity limit of 20% during any six-minute averaging period, except for one period per hour during which opacity may not exceed 27% (40 CFR 60.43b(f)). Note that emissions standards for PM and opacity apply at all times except during periods of startup, shutdown, or malfunction.

Compliance provisions and demonstration methods for PM are described fully in 40 CFR 60.46b. Continuous emission monitoring systems are required for opacity in accordance with 40 CFR 60.48b(a). In addition, the facility must submit semi-annual excess emission reports required by 40 CFR 60.49b(h). Please note that PSD limits for PM and opacity are more stringent than the requirements of Subpart Db.

B. Federal New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines

The requirements of 40 CFR 60 Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* are applicable to the Owners and Operators of stationary compression ignition internal combustion engines (CI ICE) that commence construction[7] after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pumps engines; or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

The fire pump proposed for the LBB facility is subject to Subpart IIII and is certified by the engine manufacturer to meet the applicable emission standards set forth in 40 CFR 60.4205(c). The diesel fuel used in the fire pump engine must meet the sulfur limits specified in 40 CFR 60.4207. All the applicable requirements of Subpart IIII are included in the permit.

C. Federal Accidental Release Requirements - Clean Air Act Section 112(r)

LBB has identified that the proposed biomass boiler and supporting equipment will not be subject to the provisions of 40 CFR 68 for the Federal Accidental Release Program in that it plans to use aqueous ammonia solution at less than 20% ammonia, by weight.

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[6] Oil firing for the biomass boiler is limited to startups only. The draft permit limits the annual capacity factor for oil to 5%. Note that 40 CFR 60.44b(l)(1) requires oil annual capacity factor to be limited to less than 10% in order to avoid Subpart Db requirements for NOx emissions from the boiler. However, Env-A 4602.42 (*Carbon Dioxide Budget Trading Program*) is more stringent in that it requires fossil fuel (i.e., oil in this case) annual capacity factor to be limited to less than 5% in order to opt out of Env-A 4600.

[7] For the purposes of 40 CFR 60 Subpart IIII, the date that construction commences is the date the engine is ordered by the Owner or Operator.

D. Federal Acid Rain Program

In accordance with 40 CFR 72, Federal Acid Rain Requirements, the biomass boiler will be designated as a Phase II New Affected Unit within 90 days after commencement of commercial operation. LBB will need to submit a Phase II Acid Rain Application in accordance with the requirements of 40 CFR 72. As required by the Federal Acid Rain Program, LBB will be required to acquire SO_2 allowances in the amount of one allowance for each ton of SO_2 emitted in accordance with 40 CFR 72. In addition, LBB may be required to install CEMs that meet the applicable requirements of 40 CFR 75.

E. Maximum Achievable Control Technology (MACT) Requirements for New Sources - Clean Air Act Section 112(g)

The Clean Air Act Amendments of 1990 require the EPA to regulate large facilities that emit one or more of the 185 listed hazardous air pollutants (HAPs). EPA published a list of industrial source categories that emit one or more of these HAPs on July 16, 1992, for which the agency was required to develop standards requiring application of stringent controls, known as maximum achievable control technology (MACT). On September 13, 2004, EPA issued *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* (40 CFR 63, Subpart DDDDD). However, the Court of Appeals for D.C. vacated and remanded Subpart DDDDD to EPA on June 8, 2007. In the absence of a revised final rule, a case-by-case MACT analysis is required to satisfy the requirements of Section 112(g) of the Clean Air Act.

Newly constructed units are subject to 112(g) requirements if they have the potential to emit major[8] amounts of HAPs. Sources subject to 112(g) must submit a case-by-case MACT determination to the permitting authority for review in accordance with the provisions of 40 CFR Section 63, *National Emission Standards for Hazardous Air Pollutants for Source Categories* (NESHAP). DES administers the NESHAP program in New Hampshire. DES is responsible for carrying out the case-by-case MACT determination review, as well as the issuance of any MACT approval.

LBB is classified as a major stationary source of HAPs, as HAP emissions are expected to exceed 10 tpy for a single HAP and 25 tons per year for a combination of HAPs. Since the facility is a major HAP source, and because no specific MACT standard currently exists for this source category, the biomass boiler is subject to a case-by-case MACT determination under Section 112(g) of the Clean Air Act. The application submitted by LBB included a case-by-case MACT determination as required by 40 CFR 63.42(c)(2) and 63.43(c)(ii), and the New Hampshire Code of Administrative Rules Env-A 607.01(aa), and Env-A 607.03(e).

MACT for a newly constructed device is the emission limitation which (1) is not less stringent that the emission limitation achieved in practice by the best controlled similar source, and (2) 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 major source.

[8] Major sources are those facilities with the potential to emit 10 tons per year (tpy) of any on hazardous air pollutant or 25 tpy of a combination of HAPs. Section 112(b) of the Clean Air Act Amendments contains the list of HAPs.

LBB proposed the following limitations in their case-by-case MACT determination:

Table 3 - Summary of Proposed MACT Limitations for the Biomass boiler	
Pollutant/Parameter	**Emission Limit or Monitoring/Testing Requirement**
Particulate Matter	0.010 lb/MMBtu
Hydrogen Chloride (HCl)	0.000834 lb/MMBtu
Mercury (Hg)	0.000003 lb/MMBtu
Carbon Monoxide	0.075 lb/MMBtu
Emissions Monitoring	▪ Install and operate Continuous Opacity Monitor (COMS) to demonstrate ongoing compliance with the opacity standards. ▪ Install Continuous Emissions Monitors (CEMS) for CO and % O_2.
Performance and Initial Compliance Tests	▪ Initial performance testing required for PM, HCl, Hg, and opacity.
Required Plans	LBB must develop the following site-specific plans: ▪ Startup, shutdown, and malfunction plan ▪ Performance test plan (submitted 60 days before testing) ▪ CEMS and COMS QA/QC plan ▪ Pollution control equipment operating plan

F. NESHAP for Reciprocating Internal Combustion Engines

40 CFR 63 Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Engines* established emission and operating limitations for HAP emissions from new and existing reciprocating internal combustion engines (RICE) located at both major and area sources of HAP emissions.

In accordance with 40 CFR 63.6590(c), a compression ignition stationary RICE with a site rating of less than or equal to 500 hp must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII. No further requirements apply for such engines under Subpart ZZZZ. The diesel fire pump (323 hp) proposed to be installed at LBB facility meets this criteria.

G. New Hampshire State Standards

DES has a number of state air pollution regulations that are applicable to the proposed facility. These applicable regulations are adopted under the authority of RSA 125-C, 125-I and 125-J and are codified in the New Hampshire Code of Administrative Rules Env-A 100 et. seq., *Rules Governing the Control of Air Pollution*. The substantive portions of these state requirements include, but are not limited to, the sections listed below:

1. Chapter Env-A 200 - *Procedural Requirements*
2. Chapter Env-A 300 - *Ambient Air Quality Standards*
3. Chapter Env-A 500 - *Standards Applicable to Certain New or Modified Facilities and Sources of Hazardous Air Pollutants*
4. Chapter Env-A 600 - *Statewide Permit System*
5. Chapter Env-A 618 - *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Ozone Transport Region*
6. Chapter Env-A 619 - *Prevention of Significant Deterioration of Air Quality Permit Requirements*
7. Chapter Env-A 700 - *Permit Fee System*
8. Chapter Env-A 800 - *Testing and Monitoring Procedures*
9. Chapter Env-A 900 - *Recordkeeping and Reporting Requirements*
10. Chapter Env-A 1000 - *Prevention, Abatement, and Control of Open Source Air Pollution*
11. Chapter Env-A 1211 - *Nitrogen Oxides*
12. Chapter Env-A 1400 - *Regulated Toxic Air Pollutants*
13. Chapter Env-A 1700 - *Permit Application Forms*
14. Chapter Env-A 2000 - *Fuel Burning Devices*
15. *Chapter Env-A 3000 - Emissions Reduction Credits Trading Program*
16. *Chapter Env-A 3100 - Discrete Emissions Reductions Trading Program*

VII. PSD Control Technology Review

Pursuant to 40 CFR 51.166, 40 CFR 52.21, and Env-A 619, the proposed LBB project is subject to Best Available Control Technology for particulate matter, sulfur dioxide, sulfuric acid mist, carbon monoxide and beryllium. Both State and Federal regulations and policies define BACT as an emission limitation based on the maximum degree of reduction for each regulated pollutant, taking into consideration technical, economic and environmental factors. In no case shall the BACT emission limitation result in emissions of any pollutant in excess of any applicable standard under 40 CFR 60, *Standards of Performance for New Stationary Sources of Air Pollution* and 40 CFR 61, *National Emission Standards for Hazardous Air Pollutants*.

In its application, LBB conducted their "top down" BACT analysis by first identifying all possible control options, which included a search of the EPA RACT/BACT/LAER Clearinghouse (RBLC), the BACT Clearinghouse managed by the California Air Resources Board (CARB), the South Coast Air Quality Management District BACT determinations, a review of air permits issued by various state and local air permitting agencies, and discussions with air pollution control equipment manufacturers and vendors. Secondly, LBB took into consideration other technical and environmental impacts of a particular control option. Finally, LBB made a proposal of BACT for PM, SO_2, H_2SO_4, CO and beryllium by taking into consideration the factors above.

In conducting the Preliminary Determination for BACT, DES went through a similar process, including identifying all control technologies for PM, SO_2, H_2SO_4, CO and beryllium, eliminating any technically infeasible options, ranking the control technologies/emission limitations (from most to least stringent) according to most stringent, and selecting BACT.

A. Particulate matter (PM, PM_{10} & $PM_{2.5}$)

The particulate matter emissions from fuel combustion are primarily the result of non-combustibles (ash) in the fuel. In less efficient combustion systems, particulate matter may also be comprised of soot resulting from unburned hydrocarbons. In combustion systems that utilize a cold SCR system for NOx control, a small fraction of the particulate emissions is ammonium bisulfate compounds formed when the ammonia reacts with sulfur trioxide.

Particulate matter control equipment options include the following:

- Fabric filters - Commonly known as baghouses, fabric collectors use filtration to separate dust particulates from dusty gases. They are one of the most efficient and cost effective types of dust collectors available and can achieve a collection efficiency of more than 99% for very fine particulates. Dust-laden gases enter the baghouse and pass through fabric bags that act as filters. Dust is collected on the outside of the bags while clean air flows out through the center to the atmosphere. When dust layers have built up to a sufficient thickness, the bags are cleaned, causing the dust particles to fall into a collection hopper. The three most common cleaning mechanisms are shaking, reverse air and pulse jet.
- Electrostatic precipitators (ESP) - An ESP functions by electrostatically charging the dust particles in the gas stream. The charged particles are then attracted to and deposited on plates or other collection devices. When enough dust has accumulated, the collectors are shaken to dislodge the dust, causing it to fall with the force of gravity to hoppers below. The dust is then removed by a conveyor system for disposal or recycling. ESP will provide greater than 99% control of PM emissions.

- Wet scrubbers - A wet scrubber removes particulate matter from the gas stream primarily through impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% for simple spray towers.
- Mechanical dust collectors (multiclones) - Multiclones are cyclones in series or banks of small cyclones in parallel. Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution equipment such as electrostatic precipitators or baghouses. Cyclones are less efficient than either baghouses, electrostatic precipitators or wet scrubbers. Cyclones used as precleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment.

LBB has proposed a PM BACT limit of 0.010 lb/MMBtu by using a fabric filter in order to control particulate matter emissions from the boiler. The lowest permitted emission limit for PM is 0.010 lb/MMBtu. This emission limit was identified in two permits; namely, PSNH -Schiller Station (New Hampshire, issued October 25, 2004, reissued March 7, 2006) and Yellow Pine Energy Company (Georgia, issued May 15, 2009). Both the permits require a baghouse to control PM emissions. Stack testing conducted by Schiller Station showed compliance with the emission limit of 0.010 lb/MMBtu.

Based on the above discussion, DES is proposing an emission limit of 0.010 lb/MMBtu as the BACT limit for $PM/PM_{10}/PM_{2.5}$. This emission limit shall be achieved by using a fabric filter.

B. Sulfur dioxide and Sulfuric acid mist

Emissions of SO_2 and H_2SO_4 from fuel combustion result from the oxidation of sulfur compounds present in the fuel. SO_2 control equipment options include the following:

- Spray dryer/adsorbers - This technology involves spraying of reagent slurry such as sodium hydroxide into the hot flue gas stream. The intimate contact of the reagent with the SO_2 present in the flue gas (combined with proper humidity and retention time), results in the formation of sodium salts which can be removed in the downstream particulate matter removal device.
- Dry sorbent injection - Dry sorbent injection involves the addition of a dry reagent such as limestone or sodium bicarbonate into the hot combustion zone to minimize 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 in the particulate matter control device.
- 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.

LBB has proposed an emission limit of 0.012 lb/MMBtu as BACT for SO_2. LBB proposed to use clean wood (which has very low sulfur content) as fuel and if necessary use sorbent injection technology in order to achieve the proposed emission limit for SO_2. The lowest permitted SO_2 emission rate for a BFB type biomass boiler is identified as 0.014 lb/MMBtu (using dry scrubber system) in the permit for Yellow Pine Energy Company, Georgia. Note that Yellow Pine Energy is also allowed to burn bituminous coal, pet coal and tire derived fuel.

Based on the above discussion, DES is proposing emission limits of 0.012 lb/MMBtu and 0.002 lb/MMBtu (primarily achieved by using clean wood as fuel, with additional control using sorbent injection if necessary) as BACT for SO_2 and H_2SO_4 respectively.

C. Carbon monoxide

Carbon monoxide formation in boilers results from the incomplete combustion of the fuel. Control technologies for CO include:

- Oxidation catalysts
- Combustion controls

Oxidation catalysts can reduce CO emissions by promoting the oxidation of CO to carbon dioxide (CO_2) as the flue gas stream passes through the catalyst bed. Combustion control can also be used to prevent the formation of CO in the boiler. LBB has proposed to use BFB technology and flue gas recirculation to attain a BACT limit of 0.075 lb/MMBtu for CO. In a BFB type boiler, due to the intimate contact between the bed material and the fuel, improved fuel burnout occurs. This results in very low carbon monoxide and VOC emissions.

The lowest permitted emission limit for CO is 0.075 lb/MMBtu. This emission limit was identified in two permits; namely, Russell Biomass, LLC, MA (for BFB type boiler design) and PSNH-Schiller Station, New Hampshire.

Based on the above discussion, DES is proposing an emission limit of 0.075 lb/MMBtu (24-hour daily block average) through the use of good combustion control (BFB technology and flue gas recirculation) as BACT for CO.

D. Beryllium

There are no beryllium limits contained in the RBLC for wood-fired boiler operations. LBB proposed an emission limit of 1.1×10^{-6} lb/MMBtu and the use of baghouse as BACT for beryllium.

DES concurs with LBB and is proposing an emission limit of 1.1×10^{-6} lb/MMBtu and the use of baghouse technology as BACT for beryllium.

VIII. Non-Attainment NSR Control Technology Review

NOx emissions from the proposed project are subject to LAER review. Both State and Federal regulations and policies define LAER as it is defined in Section 171 of the Clean Air Act, namely "for any source, the rate of emissions which reflects: (a) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable; or (b) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent." In addition, LAER does not take into account economic feasibility.

A. Nitrogen oxides

Control technologies for NOx include:

- Selective Non-Catalytic Reduction (SNCR) - SNCR technology involves injection of a reagent such as ammonia (anhydrous or aqueous) or urea which in turn reacts with NOx to reduce those compounds to nitrogen 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. Proprietary chemicals, referred to as enhancers or additives, can be added to the reagent to lower the temperature range at which NOx reduction reactions occur.
- Selective Catalytic Reduction - SCR process involves the mixing of anhydrous or aqueous ammonia with flue gas and passing the mixture through a catalyst bed to reduce NOx to nitrogen.

LBB has proposed to install a SCR system downstream of the baghouse for the control of NOx emissions. Since the SCR system will be located after the PM control device where the exhaust temperature is lower, it is referred to as "cold" SCR system. A cold SCR system can effectively remove NOx at lower flue gas temperatures, typically between 300 to 600 ºF. 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 NOx and ammonia. In the application, LBB proposed an emission limit of 0.060 lb/MMBtu (30-day rolling average) as LAER for NOx.

A review of similar biomass boilers in New England and RACT/BACT/LAER Clearinghouse revealed the lowest permitted NOx emission limit for any comparable plant is 0.060 lb/MMBtu. This emission limit was found in PSD permits for two facilities located in New England, namely, Russell Biomass, LLC, in Massachusetts (for a 740 MMBtu/hr BFB type biomass boiler with SCR for NOx control) and Montville Power LLC, in Connecticut (for a 600 MMBtu/hr stoker fired biomass boiler with Regenerative SCR for NOx control). Other facility permits that were reviewed include Clean Power Berlin, Concord Steam Corporation and PSNH-Schiller Station, all of which are located in New Hampshire.

Based on the above discussion, DES is proposing an emission limit of 0.060 lb/MMBtu (based on a 30-day rolling average) along with the use of a cold SCR system as LAER for NOx.

B. Ammonia

LBB has proposed the use of a SCR system to control NO_x emissions from the boiler. As explained above, the SCR system will utilize aqueous ammonia as a reagent to reduce NO_x emissions from the boiler to nitrogen and water. In order to maximize NO_x reduction, the molar ratio of ammonia to NO_x must exceed the stoichiometric ratio needed to fully consume the ammonia. The unreacted ammonia is commonly referred to as "ammonia slip" and would be emitted through the exhaust stack for the boiler. Ammonia slip does not remain constant as the SCR operates, but increases as the catalyst activity decreases. It is initially low when the catalyst is new and increases up to the design limit at the end of the catalyst's life.

DES is proposing a limit of 10 parts per million (ppm, dry volume) at 6% oxygen for the ammonia slip from the SCR system. This ammonia emission limit will ensure minimal NOx but is still low enough to prevent health risks from low-level ammonia exposure. DES will require LBB to install a CEMS to continuously monitor the ammonia slip.

C. Volatile Organic Compounds

As explained in Section VII.C of this document, BFB type boiler has inherently low VOC emissions due to improved fuel burnout. LBB states that the biomass boiler will emit VOC at a rate of 0.010 lb/MMBtu. At this emission rate, the proposed LBB facility is not a major source of VOCs, therefore the facility is not subject to LAER or offset requirements for VOC emissions. DES will require that LBB perform an EPA Method stack test to verify the VOC emission rate from the boiler.

IX. Emissions Offset Requirements

The proposed LBB facility is subject to the NO_x emission offset requirement of NSR. Since the LBB facility is located outside the four-county ozone classified non-attainment area, the emissions of NO_x must be offset at a ratio of 1.15 to 1.0. Based on the NOx emission limit of 245 tons/year, LBB is required to obtain 282 tons of NOx emission offsets. At this time, LBB is working with DES on obtaining emissions reduction credits (ERC's) to fulfill the offset requirement.

If the emissions offsets are obtained from a stationary source located beyond a certain distance from the proposed facility, a higher ratio of emissions offsets will need to be obtained. The additional quantity of emissions offsets will depend on the distance between the proposed facility and the stationary source from which the emissions offsets were originally generated.

X. Summary Table of Proposed BACT/LAER Limitations for the Biomass Boiler

Table 4 below provides a summary of proposed BACT/LAER limitations:

Table 4 - Summary of BACT/LAER Limits			
Pollutant	**Limitation**	**Technology BACT/LAER**	**Compliance Verification**
$PM/PM_{10}/PM_{2.5}$	0.010 lb/MMBtu	Baghouse BACT	Stack test
Sulfur dioxide	0.012 lb/MMBtu	Use of Clean wood & sorbent injection BACT	Stack test
Sulfuric acid mist	0.002 lb/MMBtu	Use of Clean wood & sorbent injection BACT	Stack test
Nitrogen oxides	0.060 lb/MMBtu	SCR LAER	CEMS
Carbon monoxide	0.075 lb/MMBtu	Combustion controls (BFB technology) BACT	CEMS
Beryllium	1.1×10^{-6} lb/MMBtu	Baghouse BACT	Stack test
Opacity	10 % (6-minute block average)	Good Combustion Practices BACT	COMS
Ammonia	10 ppmvd @ 6% O_2	N/A	Stack test

XI. Summary of BACT/LAER limitations for the Cooling Tower and the Fire pump

A. Cooling Tower

Particulate matter emissions occur from the cooling tower when suspended solids contained in water used in the boiler becomes airborne as steam/hot water is cooled. This is known as cooling tower “drift”. The cooling tower proposed for the LBB facility will utilize a state of the art drift eliminator that limits drift to 0.0005% of the recirculating liquid rate. This level of control is consistent with other cooling towers recently permitted at similar projects (including the cooling tower at Russell Biomass facility in MA). Therefore the PM/PM_{10} BACT for cooling tower shall be as follows:

- A drift loss rate of less than 0.0005% of the recirculating water flow.

B. Fire pump

The fire fump is subject to Federal New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII). Compliance with the emission standards specified in this rule along with the use of ULSD as fuel and an operating limit of 500 hours per year is considered BACT/LAER for the fire pump.

XII. Air Quality Impact Analysis

A. Ambient Air Quality Impact Analysis

An ambient air quality impact analysis was performed to assess predicted air quality concentrations from the LBB facility against applicable state and federal standards and guidelines. The modeling analysis was performed by ESS Group, Inc. (ESS). The emission points for the proposed power plant consist of a stack exhausting the wood boiler, a four-cell cooling tower and a fire pump. Standard modeling procedures were followed in the evaluation, using EPA-approved models and methodologies. In addition to the evaluation of National Ambient Air Quality Standards (NAAQS), projected impacts from the facility were compared against Class I and II increment levels, visibility and acid deposition thresholds and additional requirements of the PSD program.

Results of modeling analysis are discussed in detail in the attached modeling memo dated May 28, 2010.

B. Toxic Air Pollutant Evaluation

Chapter Env-A 1400 *Regulated Toxic Air Pollutants* requires an evaluation of the potential impacts of regulated toxic air pollutants. For this facility, it was determined that air toxics emissions are possible due to ammonia slip from the SCR system and free chlorine emissions from the cooling tower. LBB has proposed an ammonia slip emission limit of 20 ppmvd at 7% oxygen. However, DES has included in the permit a more stringent ammonia slip emission limit of 10 ppmvd at 6% oxygen.

The maximum impacts of these compounds are shown below in Table 5 and were compared against Ambient Air Limits (AALs) for both 24-hour and annual averaging periods. All impacts were predicted to be below the AALs using screening modeling.

Table 5 - Maximum Impacts (ug/m^3) of Ammonia & Chlorine modeled at 8760 hrs/yr

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL	Pass/Fail
Ammonia[9]	6.92	100	2.21	100	PASS
Chlorine	0.37	7.5	0.18	7.5	PASS

Sodium hydroxide (CAS # 1310-73-2) and Sodium bisulfite (CAS# 7631-90-5) are also emitted from the cooling tower due to the usage of water treatment chemicals. Emissions of these two regulated toxic air pollutants are below the de minimis levels specified in Table 1450-1 *Table Containing the List Naming all Regulated Toxic Air Pollutants*.

[9] Emission rate is based on 20 ppm ammonia slip rate, though permit will limit ammonia slip to 10 ppm @ 6% O_2

XIII. Environmental Justice

LBB performed an environmental justice assessment using the policy guidance and framework of the "Toolkit for Assessing Potential Allegations of Environmental Injustice" published by 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 LBB facility results in neither a significant adverse impact nor a disproportionate impact to any group of residents. The air modeling discussed in Section XII.A of this document concludes that all air quality impacts in the community are below EPA established significant impact levels (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 LBB project's air quality impacts are not significant or adverse. Further, as discussed in Section XII.A of this document, the predicted 24-hour and annual ambient air quality impacts of fine particulate emissions from the LBB 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 disproportionately impacted.

The LBB facility is undergoing permitting through 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.

XIV. Conclusion

It is the recommendation of DES that a NSR/PSD Permit be granted to LBB. This recommendation is based upon the review of the application submitted by LBB and is supported by the findings outlined in this Preliminary Determination.

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Intraoffice Memorandum

TO:	Padmaja Baru, NSR Program Manager Permitting and Environmental Health Bureau	**DATE**: May 28, 2010
FROM:	Jim Black, Dispersion Modeler Permitting and Environmental Health Bureau	**AFS #**: 3300790137 **Application #**: 09-0285
SUBJ:	Laidlaw Berlin BioPower, LLC – Hutchins Street, Berlin Modeling for a Proposed Wood-Fired Power Plant	**UTM E**: 326984 **UTM N**: 4926531 NAD83

Modeling Overview

DES reviewed an ambient air quality impact analysis for the proposed Laidlaw Berlin BioPower, LLC (LBB) facility in Berlin. LBB proposes 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. The facility is subject to provisions of the Prevention of Significant Deterioration (PSD) program for a number of pollutants due to its emissions and thus requires a detailed modeling analysis to determine its potential air quality impacts. In addition to an evaluation of National Ambient Air Quality Standards (NAAQS), the facility must compare its projected impacts against Class I and II increment levels, visibility and acid deposition thresholds and additional requirements of the PSD program. The emission points for the proposed power plant consist of a stack exhausting the wood boiler, a four-cell cooling tower and a fire pump.

The modeling analysis was performed by ESS Group, Inc., who submitted a modeling protocol for the facility in November, 2009. DES responded soon after with comments and an initial modeling analysis was submitted by ESS in December, 2009 as part of the air permit application. The modeling analysis was updated in April, 2010 after additional comments by DES and was finalized in May, 2010. All modeling was done in accordance with DES and EPA guidance.

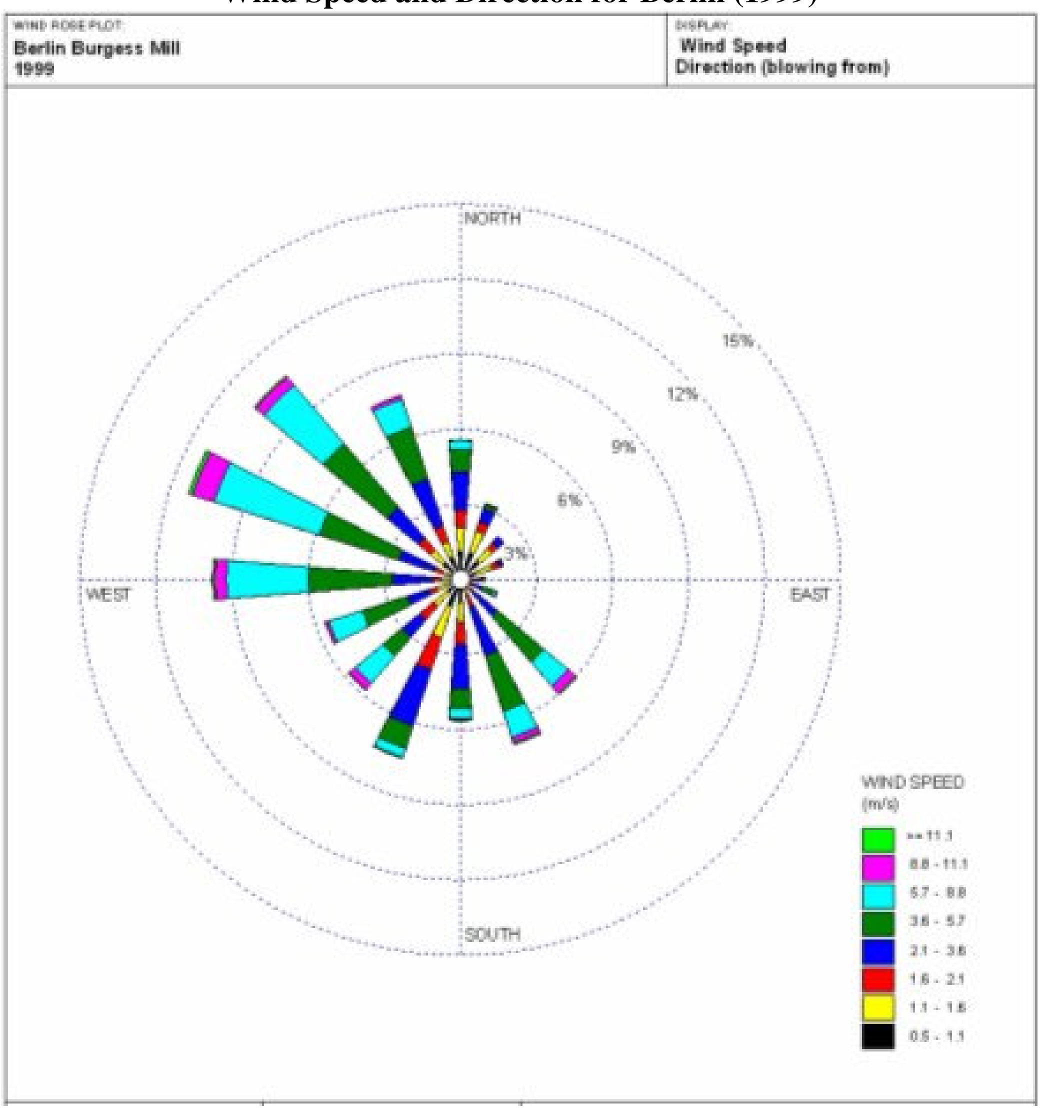
LBB looked at a number of different operating conditions for the biomass boiler, including various loads, temperatures and wood fuel moisture content. All devices were assumed to operate simultaneously at 8760 hrs/yr, though the fire pump will be limited by permit condition to 500 hrs/yr. ESS also modeled a cold startup condition for the boiler, assuming a 12 hour time period (using oil and wood in combination) with the boiler operating at normal conditions for the remaining 12 hours of the day.

Air Quality Models and Input Data

ESS used SCREEN3 (96043) and AERMOD (09292) to perform the majority of the analyses required for this project. SCREEN3 was used for the initial model runs to determine the worst-case operating conditions for the boiler. All subsequent analyses used the most recent version of AERMOD, which is the EPA-approved dispersion model for these applications. AERMOD was run with over 2800 receptors extending out to 15 km from the proposed source and another 226 receptors in the New Hampshire Class I areas to evaluate the impacts of facility emissions on the higher elevation regions of the White Mountains. DES and ESS have worked closely with the Federal Land Manager (FLM) to determine the appropriate analyses and methods to assess impacts in these wilderness areas. Based on FLM guidance ESS used the VISCREEN (88341) model to evaluate visibility impacts in the Class I areas and compared results to published visibility screening criteria. Acid deposition was modeled using AERMOD while the impacts on local visibility from the cooling tower plume were evaluated using the SACTI model.

Prior to the submittal of the dispersion modeling protocol, ESS worked with DES to locate and process on-site meteorological data for use in the analysis. The on-site data were from 1999 and were taken at the meteorological tower located just to the east of the property. The data set was supplemented with airport observations from Berlin and Whitefield in the case of missing wind and temperature data. Land use characteristics near the meteorological site were used to determine atmospheric dispersion parameters, in accordance with EPA guidance. DES' review of the final meteorological data set determined that it is representative of the Berlin area and is the best available data set for this project. Figure 1 shows the wind rose for 1999, giving wind speed and direction (from which the wind is blowing). The 1999 data set was compared to earlier Berlin data from 1986 to 1990 and the distribution of wind speed and direction was shown to be consistent.

Figure 1
Wind Speed and Direction for Berlin (1999)



The LBB property will be inaccessible to the general public due to a fence. For this reason ESS did not initially model on-property impacts since this is not considered ambient air. It was later determined, however, that public access walking trails have been proposed within the property boundary so ESS added receptors along the accessible paths along most of the property with the exception of the areas immediately west and south of the building complex. ESS will add additional receptors within the fence line in the future in the event that LBB decides to sell or lease a portion of their property to another company.

Modeled input data (including controlled emission rates) for the LBB biomass boiler are shown in Table 1 and reflect a variety of operating scenarios. The boiler will operate in a range of 70% to full load and will combust wood with varying moisture contents. There are two distinct exhaust temperatures, corresponding to conditions with and without the operation of a heat exchanger to recover waste heat. The data shown in Table 1 represent operation of the boiler at steady state conditions. As mentioned the boiler impacts were also analyzed under startup mode for 12 hours/day. This condition was modeled with the potential for occurring at any hour of the day in order to predict the maximum short-term impacts under a variety of meteorological conditions.

Table 1
Modeled Emission Rates (lb/hr) and Stack Parameters for the LBB Biomass Boiler

	Load Condition (%)	100	100	100	100	70	70	70	70
	Fuel Moisture (%)	37.6	37.6	50	50	37.6	37.6	50	50
	Exhaust Temp (^oF)	369	260	366	260	375	260	370	260
Emission Rates	SO_2	12.30	12.30	13.37	13.37	8.63	8.63	9.38	9.38
	PM10 / PM2.5	10.25	10.25	11.14	11.14	7.19	7.19	7.82	7.82
	NOx	61.51	61.51	66.86	66.86	43.16	43.16	46.92	46.92
	CO	76.89	76.89	83.57	83.57	53.96	53.96	58.64	58.64
Stack Data	Stack Height (ft)	320	320	320	320	320	320	320	320
	Exit Diameter (ft)	11.25	11.25	11.25	11.25	11.25	11.25	11.25	11.25
	Flow Rate (ACFM)	382,000	331,773	448,000	390,508	270,000	232,814	315,891	274,026
	Stack Orientation	vertical and unobstructed							

Table 2 shows the stack and emissions data for the other LBB devices. With the exception of one hour per week of maintenance testing, the fire pump will not operate concurrently with the biomass boiler. The cooling tower consists of four cells which will be equipped with drift eliminators to minimize particulate matter emissions and to limit release of water droplets. Aerodynamic downwash was incorporated into the modeling analysis to address the effects of the existing and proposed structures on the exhaust plumes.

Single-Source Impact Analysis

The results of the SCREEN3 screening modeling predicted that the worst-case air quality impacts from the biomass boiler come from the device running at 100% load and with the heat exchanger (260 $^\circ$F exit temperature) in operation. Wood moisture contents of 50% and 37.6%

produced similar results so both these conditions were evaluated with refined modeling using the worst-case load and exhaust temperature. The maximum predicted impacts from the LBB facility alone are shown in Tables 3 and 4 for NAAQS and Class II increment, respectively. ESS' analysis looked at the highest individual impact contributions from the LBB devices and summed the results to give a conservative estimate of overall impacts from the facility. DES performed additional analyses to confirm the results and to verify the conclusions made in the ESS dispersion modeling report.

Table 2
Modeled Emission Rates (lb/hr) and Stack Parameters for the LBB Fire Pump and Cooling Tower

	Parameter	**Fire Pump**	**Cooling Tower***
Emission Rates	SO_2	0.0034	0
	PM10 / PM2.5	0.11	0.075
	NOx	2.13	0
	CO	1.86	0
Stack Data	Stack Height (ft)	25	48
	Exit Diameter (ft)	0.5	31.6
	Flow Rate (ACFM)	1,973	1,300,000
	Exhaust Temp (^oF)	1,058	96
	Stack Orientation	vertical/unobstructed	vertical/unobstructed

* data are for each of the four cells

Table 3
Maximum LBB Impacts (ug/m^3) compared to NAAQS

Pollutant	Avg Time	Contrib	Bckg*	Impact	NAAQS	Pass/Fail
SO_2	Annual	0.12	16	16.12	80	PASS
	24-Hour	1.14	39	40.14	365	PASS
	3-Hour	4.74	79	83.74	1,300	PASS
PM10	Annual	0.13	14	14.13	50	PASS
	24-Hour	1.48	30	31.48	150	PASS
PM2.5	Annual	0.13	9	9.13	15	PASS
	24-Hour	1.48	21	22.48	35	PASS
NO_2**	Annual	0.72	15	15.72	100	PASS
	1-Hour	82.91	53	135.9	188	PASS
CO	8-Hour	35.96	--	35.96	10,000	PASS
	1-Hour	177.98	--	177.98	40,000	PASS

* background data from Claremont, except NO_2 from Brentwood – background not tracked for CO
** NO_2 impacts include a 75% conversion rate of NOx to NO_2 and have been adjusted to meet EPA Tier 3 emissions standards for the fire pump

Table 4
Maximum LBB Impacts (ug/m^3) compared to Class II Increment

Pollutant	Avg. Time	Contrib.	Increment	Pass/Fail
SO_2	Annual	0.12	20	PASS
	24-Hour	1.14	91	PASS
	3-Hour	4.74	512	PASS
PM10	Annual	0.13	17	PASS
	24-Hour	1.48	30	PASS
PM2.5	Annual	0.13	5	PASS
	24-Hour	1.48	7	PASS
NO_2	Annual	0.72	25	PASS

Class II increment consumption was not evaluated in Coos County prior to LBB's application since a PSD application had never been submitted for a source in that county. Since LBB's PSD application of December 16, 2009 is the first for that area, the baseline date was triggered and increment consumption for Coos County was initiated.

The modeling analysis for the LBB source alone predicted impacts to be well below NAAQS (by comparing the "*Impact*" results to the "*NAAQS*" in Table 3) as well as below Class II increment levels (shown in Table 4 by comparing the "*Contrib.*" results to the "*Increment*" column). The maximum impacts from the biomass boiler were predicted to be approximately 2 miles to the south and southeast of the LBB facility (depending on the averaging period). The highest impacts from the cooling tower and fire pump were concentrated just beyond the property line to the north of the power plant. All devices were assumed to operate at their maximum permitted levels, with the boiler operating continuously for 8760 hrs/yr.

Table 3 shows background levels ("*Bckg*") of criteria pollutants provided to ESS by DES. As required under the PSD program the source is obliged to evaluate the need for pre-construction air monitoring and must perform such monitoring if their maximum predicted impacts are above Significant Monitoring Concentrations. ESS performed this analysis and determined that additional air quality monitoring is not required for this project based on the worst-case modeled impacts.

Class I Increment Consumption

Due to its PSD status and its proximity to the Presidential Range-Dry River Wilderness and the Great Gulf Wilderness Class I areas, LBB is required to evaluate Class I increment consumption, along with visibility and deposition in these pristine locations. Using input from the FLM the consultant applied AERMOD to compare impacts to Class I increment levels. A total of 226 receptors were modeled using receptor locations and elevations taken from the National Parks Service web site. The results of that analysis are presented in Table 5 and show all impacts to be well below established Class I increments.

Though no exceedances of any Class I increments are predicted, the modeling analysis estimated impacts of 3-hour SO_2 and 24-hour PM2.5 to be at or above EPA-defined significance levels (1.0 ug/m^3 for 3-hour SO_2 and 0.13 ug/m^3 for 24-hour PM2.5). These levels are used to determine the need for interactive modeling to look at the combined impacts from a number of sources.

Table 5
Maximum LBB Impacts (ug/m^3) compared to Class I Increment

Pollutant	Avg. Time	Contrib.	Increment	Pass/Fail
SO_2	Annual	0.02	2	PASS
	24-Hour	0.19	5	PASS
	3-Hour	**1.00**	25	PASS
PM10	Annual	0.02	4	PASS
	24-Hour	0.16	8	PASS
PM2.5	Annual	0.02	1.2	PASS
	24-Hour	**0.16**	1.9	PASS
NO_2	Annual	0.08	2.5	PASS

Note: values in bold are either at or above EPA-defined significant impact levels

Visibility

Visibility modeling was performed by ESS to determine the extent of visibility impairment due to operation of the proposed facility. The VISCREEN model was used to calculate the potential for color difference (delta E) and plume contrast due to the LBB exhaust plume at the closest distance to the Class I areas. The initial screening analysis determined that the potential exists for the biomass boiler exhaust plume to cause a color difference when viewed against the sky inside of the Class I area. Further modeling showed that the meteorological conditions which can cause this difference in coloration only persist for up to three hours at a time. Using the strongest wind speed in that data set, the shortest transport time to the Class I areas is five hours. Since the conditions which can cause an adverse impact on visibility only persist for three hours, there is not enough time for the visible plume to reach the wilderness areas before it disperses. For this reason visibility impairment in the Class I areas is not expected due to operation of the LBB facility.

Acid Deposition

An additional requirement of PSD sources established by the FLMs is the assessment of acid (sulfate and nitrate) deposition on the Class I areas. ESS used published procedures and guidance obtained directly from the FLM to model the potential impacts of wet and dry gaseous and particle deposition and compared the results to the Deposition Analysis Threshold (DAT). The DAT is essentially an action level which, if exceeded, may warrant additional analysis. For the eastern United States the DAT for sulfates and nitrates is 0.01 kg/hectare-yr. The deposition modeling analysis predicted a maximum impact (combined gas and particle deposition) of nitrogen to be above the DAT for nine receptors in the northernmost Class I area. DES is currently working with the FLM to evaluate and interpret the results and to determine what further analysis, if any, is needed. Sulfur deposition was predicted to be at most 54% of the DAT.

Interactive-Source Impact Analysis

As shown in Tables 3 and 4, the maximum predicted impacts from the LBB facility alone were below NAAQS and Class II increment levels and in fact were predicted to be below significant impact levels. According to EPA guidance this exempts the source from performing interactive modeling (based on their low impacts) since they could not either cause or contribute to an air quality violation. However, due to the number of sources in the area, DES decided to perform an interactive NAAQS and Class II increment analysis to verify this assumption. To do this, DES looked at all permitted air emissions sources within 15 km (9.3 miles) from the LBB site and modeled these sources together, assuming all are operating simultaneously and at their permitted emission limits. The DES modeling results confirmed that the proposed source will not cause or significantly contribute to any exceedance of an air quality standard in the modeling region.

Though the ESS modeling predicted insignificant impacts when compared to NAAQS and Class II increments, the facility was predicted to have significant SO_2 and PM2.5 impacts in the Class I areas (though all impacts were well below Class I increments). For this reason the source was required to perform interactive modeling using the set of receptors covering the two wilderness areas. In consultation with the FLM, DES developed an interactive source inventory using criteria agreed upon by both agencies. The source inventory consists of all permitted SO_2 and PM2.5 sources which meet the following criteria:

1. All increment-consuming sources within 20 km of the Class I areas, independent of total emissions.
2. All major sources (as defined under the PSD program) within 50 km of the Class I areas.
3. All major sources in the 50 km to 60 km range of the Class I areas with a Q/D □ 10, where Q is the total annual tonnage of SO_2, PM10 and NOx and D is the closest distance to the Class I area in km.

The above criteria resulted in a Class I inventory of five sources located in New Hampshire and Maine. All sources were assumed to be operating concurrently and at their maximum permitted emission limits. The results of the ESS Class I interactive modeling analysis are shown in Table 6 and predict impacts to be below Class I increments for the significant pollutants and averaging periods.

Table 6
Maximum Interactive-Source Impacts (ug/m^3)
compared to Class I Increment

Pollutant	Avg. Time	Contrib.	Increment	Pass/Fail
SO_2	3-Hour	4.06	25	PASS
PM2.5	24-Hour	0.44	1.9	PASS

Additional PSD Impact Analyses

Local Visibility Impairment

The potential effects of the proposed project on visibility in the immediate area surrounding the site were assessed for the boiler stack plume and the water plume from the cooling tower. Boiler stack gas opacity will be monitored continuously to ensure that it meets permit limits. The cooling tower was analyzed using the SACTI model which predicts parameters such as amount of fogging and icing, plume height and plume dimensions. The model did not predict any ground-level fogging or icing and estimated the cooling tower plume to rise below the level of the boiler building (165 ft) under nearly all meteorological conditions. The plume was predicted to rise above the boiler building for 5 hours per year but during these times high humidity would result in clouds and/or fog which would obscure the moisture plume.

Impacts Due to Growth and Construction

ESS concluded that impacts from construction will be minimized due to the fact that this project will use the existing boiler and some existing structures. Since the LBB project will be located at a former paper mill there will be significantly lower emissions than were in existence when the mill was operational. LBB expects the facility to provide long-term economic benefits to the area through the creation of jobs and by adding to the tax base.

Soils and Vegetation

A quantitative analysis was performed to evaluate the effects of the proposed facility on soils and sensitive vegetation, using criteria established by EPA as contained in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. ESS calculated the potential impacts of SO_2, NO_2, CO, beryllium and lead for a variety of averaging periods and compared those results to the published EPA Vegetation Sensitivity Concentrations. All impacts from the LBB source were predicted to be below these levels.

Regulated Toxic Air Pollutant Evaluation

Chapter Env-A 1400 of the DES *Rules Governing the Control of Air Pollution* requires an evaluation of the potential impacts of regulated toxic air pollutants. For this facility, it was determined that air toxics emissions are possible due to ammonia slip from the SCR system on the biomass boiler stack and chlorine from the cooling tower drift. The maximum impacts of these compounds are shown below in Table 7 and were compared against Ambient Air Limits (AALs) for both 24-hour and annual averaging periods. All impacts were predicted to be below the AALs using screening modeling.

Table 7
Maximum Ammonia Impacts (ug/m^3) compared to AALs

Pollutant	24-Hour Impact	24-Hour AAL	Annual Impact	Annual AAL	Pass/Fail
Ammonia*	6.92	100	2.21	100	PASS
Chlorine	0.37	7.5	0.18	7.5	PASS

* emission rate is based on 20 ppm slip rate, though permit will limit source to 10 ppm

STATE OF NEW HAMPSHIRE
DEPARTMENT OF ENVIRONMENTAL SERVICES
AIR RESOURCES DIVISION
CONCORD, NEW HAMPSHIRE

NOTICE OF PERMIT REVIEW, PUBLIC HEARING, AND COMMENT PERIOD FOR TEMPORARY PERMIT, NON-ATTAINMENT NEW SOURCE REVIEW (NSR) AND PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AIR PERMIT

Pursuant to the New Hampshire Code of Administrative Rules, Env-A 621, notice is hereby given that the Director of the New Hampshire Department of Environmental Services, Air Resources Division (Director), has received an application for a Temporary Permit, Non-Attainment New Source Review (NSR) and Prevention of Significant Deterioration (PSD) air permit from, and based on the information received to date, intends to **issue such Temporary, NSR, and PSD Permit to:**

Laidlaw Berlin BioPower, LLC
90 John Street – 4th Floor
New York, NY 10038

For a:

70 Megawatt Biomass-Fired Electric Generating Facility

Located at:

57 Hutchins Street
Berlin, NH 03570

1. The purpose of this permit is to authorize Laidlaw Berlin BioPower, LLC (LBB) to construct a biomass-fired electric generating facility at the above address. LBB will generate electricity for sale to the grid. Significant emissions units include a biomass-fired boiler rated at 1,013 million British thermal units per hour (MMBtu/hr), a 4-cell cooling tower, and an emergency fire pump engine.

2. The air emissions from the proposed facility are listed in the following table:

Maximum Projected Facility-wide Emissions	
Pollutant	**Emissions (tons per consecutive 12-month period)**
Nitrogen oxides (NOx)	245
Particulate matter (PM)	43.3
Sulfur dioxide (SO_2)	48.7
Carbon monoxide (CO)	308
Volatile Organic Compounds (VOCs)	41.1
Sulfuric acid mist (H_2SO_4)	8.1
Beryllium	0.0045

3. Pursuant to N.H. Code of Administrative Rules, Env-A 618.04 *Emission Offset Requirements*, LBB is required to obtain nitrogen oxides (NOx) emission offsets in the ratio of 1.15:1, or approximately 282 tons of offsets. These NOx emission offsets will be obtained in accordance with Env-A 3000 *Emissions Reductions Credits Trading Program* or Env-A 3100 *Discrete Emission Reduction Trading Program*.

4. DES has determined, based upon an ambient air quality impact analysis, that the facility's air emissions will not violate any state or federal air quality standards, nor exceed any PSD increment standards. Details regarding the degree of increment consumption are contained in the Preliminary Determination.

5. The determinations of NSR Lowest Achievable Emission Rate (LAER) and PSD Best Available Control Technology (BACT) for the biomass boiler, including the type of equipment and the prescribed emission limit, in pounds per MMBtu (lb/MMBtu) are listed in the following table:

LAER and BACT Emission Limitations and Control Technology		
Pollutant	**Emission Limitation (lb/MMBtu)**	**Control Technology**
Nitrogen oxides (NOx)	0.060	Selective Catalytic Reduction (SCR) System LAER
Particulate matter (PM)	0.010	Baghouse BACT
Sulfur dioxide (SO_2)	0.012	Low sulfur fuel & dry sorbent injection BACT
Carbon monoxide (CO)	0.075	Good combustion practices BACT
Sulfuric acid mist (H_2SO_4)	0.002	Low sulfur fuel & dry sorbent injection BACT
Beryllium	1.1×10^{-6}	Baghouse BACT

All information, to the extent permitted by N.H. RSA 91-A and RSA 125-C:6, VII, submitted by the applicant; the Department's analysis of the effect of the proposed facility on air quality; the Preliminary Determination, the draft Temporary/PSD/NSR permit, and all other materials, if any, considered in making the Preliminary Determination are available for inspection with the Director, New Hampshire Department of Environmental Services, Air Resources Division, located at 29 Hazen Drive, P.O. Box 95, Concord, NH 03302-0095, (603) 271-1370. Information may be reviewed at the Department's office during working hours from 8 a.m. to 4 p.m., Monday through Friday. Additional information may also be obtained by contacting Todd Moore at the above address and phone number. The application, Preliminary Determination, and draft permit are also available for review at the Berlin City Hall, 168 Main Street, Berlin, NH during the hours of 8:30 a.m. to 4:30 p.m., Monday through Friday and are available via DES's online OneStop database at www.des.nh.gov/onestop.

PUBLIC HEARING & COMMENT PERIOD

A public hearing regarding the air permit has been scheduled for **Thursday, July 1, 2010** at **6:00 p.m.** at the **Auditorium in Berlin City Hall, 168 Main Street, Berlin, NH**.

Comments provided at the public hearing, as well as written comments filed with the Director and received no later than 4:00 p.m. **Friday, July 2, 2010** shall be considered by the Director in making a final decision.

Robert R. Scott
Director
Air Resources Division

State of New Hampshire
Department of Environmental Services
Air Resources Division

Temporary Permit
Prevention of Significant Deterioration (PSD)
And
Non-Attainment New Source Review (NSR) Permit

Permit No: TP-0054
Date Issued: **DRAFT** Issued May 28, 2010

This certifies that:

Laidlaw Berlin BioPower, LLC
90 John St., 4th Floor
New York, NY 10038

has been granted a Temporary Permit, PSD Permit, and NSR Permit for a:

70 Megawatt Biomass-fired Electric Generating Facility

at the following facility and location:

Laidlaw Berlin BioPower, LLC
57 Hutchins Street
Berlin, NH

Facility ID No: **3300790137**
Application No: **09-0285** received December 16, 2009 – Initial Temporary, PSD, and NSR Permit

which includes devices that emit air pollutants into the ambient air as set forth in the permit application referenced above which was filed with the New Hampshire Department of Environmental Services, Air Resources Division (Division) in accordance with RSA 125-C of the New Hampshire Laws. Request for permit reissuance is due to the Division at least 90 days prior to expiration of this permit and must be accompanied by the appropriate permit application forms.

This permit is valid upon issuance and expires on **TBD**.

____
Director
Air Resources Division

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Abbreviations and Acronyms			
AAL	Ambient Air Limit	lb	pound
acf	actual cubic foot	MACT	Maximum Achievable Control Technology
ags	above ground surface	MM	million
ASTM	American Society of Testing and Materials	MW	megawatt
BACT	Best Available Control Technology	NAAQS	National Ambient Air Quality Standard
Btu	British thermal units	NESHAP	National Emission Standard for Hazardous Air Pollutants
CAA	Clean Air Act	NG	Natural Gas
CAM	Compliance Assurance Monitoring	NHDES	New Hampshire Department of Environmental Services
CEMS	Continuous Emission Monitoring System	NOx	Oxides of Nitrogen
COMS	Continuous Opacity Monitoring System	NSPS	New Source Performance Standard
cfm	cubic feet per minute	NSR	New Source Review
CFR	Code of Federal Regulations	PM_{10}	Particulate Matter < 10 microns
CO	Carbon Monoxide	$PM_{2.5}$	Particulate Matter < 2.5 microns
DER	Discrete Emission Reduction	ppm	parts per million
dscf	dry standard cubic feet	PSD	Prevention of Significant Deterioration
dscm	dry standard cubic meters	psi	pounds per square inch
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division	PTE	Potential to Emit
ERC	Emission Reduction Credit	RACT	Reasonably Available Control Technology
EG	Emergency Generator	RSA	New Hampshire Revised Statutes Annotated
ft	foot or feet	RTAP	Regulated Toxic Air Pollutant
ft^3	cubic feet	scf	standard cubic foot
gal	gallon	SIP	State Implementation Plan
HAP	Hazardous Air Pollutant	SO_2	Sulfur Dioxide
HCL	Hydrochloric Acid	SSMP	Startup, Shutdown, and Malfunction Plan
e	horsepower	TSP	Total Suspended Particulate
hr	hour	tpy	tons per consecutive 12-month period
kW	kilowatt	USEPA	United States Environmental Protection Agency
LAER	Lowest Achievable Emission Rate	VOC	Volatile Organic Compound

I. Facility Description

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. This project is considered new construction, not a modification or reconstruction of the former Fraser Pulp Mill. LBB (the Facility) 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).

The primary emission unit will be a bubbling fluidized bed boiler rated at 1,013 million British thermal units per hour (MMBtu/hr), which is capable of generating up to 600,000 pounds per hour of steam at 825ºF and 850 psig. The proposed facility also includes a new wet cooling tower, two wood fuel off-loading and storage areas and a 323 hp diesel fire pump.

LBB will be a major stationary source of nitrogen oxides (NO_x) emissions, with potential NO_x emissions greater than 100 tons per year. NOx is a precursor of ozone, and Coos County is designated as being in attainment for ozone; however, Coos County is within the New Hampshire portion of the Northeast Ozone Transport Region. Therefore, the proposed facility will be subject to state non-attainment New Source Review (NSR) (Env-A 618) for ozone, 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, LBB will also be subject to the applicable Prevention of Significant Deterioration (PSD) of air quality permit requirements for criteria pollutants other than NOx. The Division has implemented the PSD Program permitting requirements (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 pollutant with potential emissions above the significance thresholds. The PSD pollutants for this facility are particulate matter (including Total Suspended Particulate (TSP), Particulate Matter less than 10 microns (PM_{10}), and Particulate Matter less than 2.5 microns ($PM_{2.5}$)), sulfur dioxide (SO_2), carbon monoxide (CO), sulfuric acid mist (H_2SO_4), and beryllium.

The PSD program also requires additional impact analyses including:

1. Analysis of impacts on soils and vegetation, local visibility and commercial/residential/industrial growth and construction associated with the source; and
2. Analysis of impacts on Class I areas (the Great Gulf Wilderness Area approximately 18 kilometers to the south, and the Presidential Range Dry River Wilderness Area approximately 26 kilometers to the south).

LBB must also comply with the applicable subparts of the federal New Source Performance Standards (NSPS). LBB will be a major source of hazardous air pollutant (HAP) emissions and, therefore, will require application of Maximum Available Control Technology (MACT) for HAPs pursuant to the federal National Emission Standards for Hazardous Air Pollutants (NESHAPS).

Table 1 below shows the major source applicability determination for the NSR and PSD programs for the proposed facility:

Table 1 – PSD and NSR Applicability					
Pollutant	**Projected Project Emissions (tpy)**	**PSD Major Source Threshold (tpy)**	**PSD Significance Threshold (tpy)**	**NSR Major Source Threshold (tpy)**	**Triggers NSR/PSD?**
$PM/PM_{10}/PM_{2.5}$[1]	43.3/42.7/42.3	250	25/15/10[2]	N/A	**PSD**
SO_2	48.7	250	40	N/A	**PSD**
NOx	245	250	N/A	100	**NSR**
CO	308	250	100	N/A	**PSD**
VOCs	41.1	N/A	N/A	50	No[3]
H_2SO_4	8.1		7		**PSD**
Lead	0.2		0.6		No
Beryllium	0.0045		0.0004		**PSD**
Mercury	0.012		0.1		No
Vinyl Chloride	0.08		1		No

II. Permitted Activities

The Owner or Operator is authorized to construct and operate a 70 MW biomass power plant comprised of the devices identified in Table 2, pollution control equipment identified in Table 4, and all associated ancillary equipment within the terms and conditions of this Permit.

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1 All references to "particulate matter" throughout this permit mean filterable portion only, unless otherwise specified.

2 The PSD major significance threshold for $PM_{2.5}$ is 10 tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; or 40 tpy of NO_x emissions unless demonstrated not to be a $PM_{2.5}$ precursor under paragraph (b)(50) of 40 CFR 52.21.

3 While the proposed VOC increase is above the 40 tpy significant modification threshold, LBB is a minor source of VOCs under the NSR program (VOC emissions are less than 50 tpy) and, therefore, does not trigger NSR for this project.

III. Significant Activities Identification

The activities identified in Table 2 are subject to and regulated by this Permit:

Table 2 - Significant Activity Identification			
Emission Unit ID	**Device**	**Manufacturer, Model, Serial Number**	**Maximum Design Gross Heat Input Capacity and Permitted Fuel Type(s)**[4]
EU01	Boiler #1	Babcock and Wilcox Model # Custom, N/A One Primary Combustion Chamber - Bubbling Fluidized Bed Four Startup Burners - Air atomized distillate oil Serial # TBD	Primary Combustion Chamber 1,013 MMBtu/hr – Clean wood chips Approximately equivalent to 113 ton/hr Four Startup Burners (each) 60 MMBtu/hr – No. 2 fuel oil Approximately equivalent to 430 gal/hr
EU02	4-Cell Wet Cooling Tower	SPX Cooling Technologies Model #: F499-4.0-4 Serial #: TBD	Nominal circulation rate = 60,000 gal/minute
EU03	Fire Pump Engine	Cummins Model # CFP9E-F30 or equivalent Serial # TBD	2.27 MMBtu/hr – Diesel fuel oil Approximately equivalent to 16.2 gal/hr

IV. Stack Criteria

The following devices at the Facility shall have exhaust stacks that discharge vertically, without obstruction, and meet the criteria in Table 3 below:

Table 3 - Stack Criteria				
Stack ID	**Emission Unit ID**	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (ft)**	**Maximum Inside Stack Diameter (ft)**
ST01	EU01	Boiler	320	11.25
ST02	EU02	Cooling Tower	48 (each cell)	31.6 (each cell)
ST03	EU03	Fire Pump Engine	25	0.5

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[4] The hourly fuel rates presented in Table 2 are calculated assuming a heat content of 4,500 Btu/lb for wood at 50% moisture and 140,000 Btu/gal for No.2 and diesel fuel oil.

V. Pollution Control Equipment/Method Identification

With the exception of PCE03, sorbent injection, air pollution control equipment listed in Table 4 shall be operated at all times that the associated devices are operating in order to meet permit conditions. Sorbent injection is only required as necessary to meet SO_2 and H_2SO_4 emission limitations.

Table 4 - Pollution Control Equipment Identification

Pollution Control Equipment ID	Description	Purpose	Emission Unit Controlled
PCE01	Baghouse	Control of particulate matter emissions	EU01
PCE02	Selective Catalytic Reduction (SCR) System (cold side) with ammonia injection	Control of NO_x emissions	EU01
PCE03	Sorbent Injection (as needed)	Control of SO_2 emissions	EU01
PCE04	Drift Eliminators	Control of particulate matter emissions	EU02

VI. Operating and Emission Limitations

The Owner or Operator shall be subject to the operating and emission limitations identified in Table 5:

Table 5 - Operating and Emission Limitations

Item #	Requirement	Applicable Unit	Regulatory Basis
1	*Emission Standard for NO_x* NO_x emissions shall be limited to 0.060 lb/MMBtu of heat input based on a 30-day rolling average[5].	EU01	Env-A 618 (LAER) *More Stringent than* Env-A 1211.03

[5] Compliance with NO_x, CO, and ammonia slip emission standards will be determined using CEMS. Compliance with other emission standards (PM, PM_{10}, $PM_{2.5}$, SO_2, Beryllium, HCl, H_2SO_4, Mercury, and cooling tower drift (PM)) shall be determined using stack testing. The averaging time for pollutants for which compliance is determined using stack testing shall be determined by the approved test method.

Table 5 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Unit**	**Regulatory Basis**
2	*Emission Standard for PM* [6] PM, PM_{10}, $PM_{2.5}$ emissions shall each be limited to 0.010 lb/MMBtu of heat input.	EU01	Env-A 619 (BACT) & 40 CFR 63 Subpart B (Case-by-Case MACT) *More Stringent than* 40 CFR 60.43b(h)(1) & Env-A 2002.08
3	*Emission Standard for CO* CO emissions shall be limited to 0.075 lb/MMBtu of heat input based on a calendar day average.	EU01	Env-A 619 (BACT) & 40 CFR 63 Subpart B (Case-by-Case MACT)
4	*Emission Standard for SO_2* SO_2 emissions shall be limited to 0.012 lb/MMBtu of heat input.	EU01	Env-A 619 (BACT)
5	*Emission Standard for H_2SO_4* H_2SO_4 emissions shall be limited to 0.002 lb/MMBtu of heat input.	EU01	Env-A 619 (BACT)
6	*Emission Standard for Beryllium* Beryllium emissions shall be limited to 0.0000011 lb/MMBtu of heat input.	EU01	Env-A 619 (BACT)
7	*Emission Standard for Hydrogen Chloride* HCl emissions shall be limited to 0.000834 lb/MMBtu of heat input.	EU01	40 CFR 63 Subpart B (Case-by-Case MACT)
8	*Emission Standard for Mercury* Mercury emissions shall be limited to 0.000003 lb/MMBtu of heat input.	EU01	40 CFR 63 Subpart B (Case-by-Case MACT)
9	*Emission Standard for Ammonia Slip* Ammonia slip emissions shall be limited to 10 ppmvd @ 6% oxygen (O_2) dry volume based on a calendar day average.	EU01/ PCE02	Env-A 1400
10	*Operating Mode Limitation* [7] The boiler shall be operated in normal mode at all times, except during periods of startup or shutdown. Normal mode shall be defined as operating at a heat input capacity of 654 MMBtu/hr or greater (~70% of its average maximum heat input capacity of 932 MMBtu/hr).	EU01	Env-A 618 & Env-A 619

[6] *See footnote 1.*

[7] Emission standards in Table 5 Items 1 through 9 apply during normal operation only. They do not apply during startup or shutdown. Startup and shutdown emission standards are addressed in Table 5 Item 11.

Table 5 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Unit**	**Regulatory Basis**
11	*Emission Standards for Startup & Shutdown* NO_x and CO emissions shall be limited to 244.5 tpy and 307.3 tpy, respectively. This emission standard shall apply at all times, which includes normal operation, startup and shutdown. These emission standards shall remain in effect until startup & shutdown specific limits are established and incorporated into this permit pursuant to Table 6 Item 21.	EU01	Env-A 618 & Env-A 619
12	*Fuel Oil Annual Capacity Factor* The boiler shall operate at an annual capacity factor for fuel oil of 5 percent or less.	EU01	Env-A 4602.42 *More stringent than* 40 CFR 60.44b(1)(1)
13	*Fuel Oil Startup Limitation* Fuel oil shall only be burned in the boiler during startup.	EU01	Env-A 619
14	*Facility-wide annual Emission Standard for NO_x* Emissions of NO_x from the facility shall be limited to 245 tpy.	Facility-wide	Env-A 618
15	*Emission Standard for Particulate Drift* Emissions of PM from the cooling tower shall be limited to 0.0005% by weight of the cooling water flow rate.	EU02	Env-A 619
16	*Maximum Sulfur Content in Fuel Oil* The sulfur content of No. 2 fuel oil or diesel fuel oil burned in the boiler and fire pump shall not exceed 0.0015 percent sulfur by weight.	EU01 & EU03	Env-A 619 & 40 CFR 60.4207 (NSPS Subpart IIII) *More stringent than* Env-A 1604.01(a)
17	*Standard for Opacity* The opacity from the boiler shall not exceed 10 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.[8]	EU01	Env-A 619 *More stringent than* 40 CFR 60.43b(f) (NSPS Subpart Db) & Env-A 2002.02

[8] Compliance with the visible emission standard for EU01 shall be determined using a COMS.

Table 5 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Unit**	**Regulatory Basis**
18	*Activities Exempt from Visible Emission Standards* No more than one of the following two exemptions shall be taken at a time: a. During periods of startup, shutdown and malfunction, average opacity shall not exceed 20% except for one period of 6 continuous minutes in any 60-minute period; or b. During periods of soot blowing, grate cleaning, and cleaning of fires, average opacity shall be allowed to be in excess of 20%, but not more than 27% for one period of 6 continuous minutes in any 60-minute period.	EU01	Env-A 2002.04(a)
19	*Visible Emission Standard for Fuel Burning Devices Installed After May 13, 1970* The average opacity from fuel burning devices installed after May 13, 1970 shall not exceed 20 percent for any continuous 6-minute period.[9]	EU03	Env-A 2002.02
20	*Activities Exempt from Visible Emission Standards* The average opacity shall be allowed to be in excess of those standards specified in Env-A 2002.02 (Table 5 Item 19) for one period of 6 continuous minutes in any 60-minute period during startup, shutdown, or malfunction.	EU03	Env-A 2002.04(c)
21	*Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985* The particulate matter emissions from fuel burning devices installed on or after January 1, 1985 shall not exceed 0.30 lb/MMBtu.	EU03	Env-A 2002.08
22	*Fire Pump Operation* The fire pump shall only operate: a. As a mechanical or electrical power source when the primary power source for the Facility has been lost during an emergency such as a power outage; b. During normal maintenance and testing as recommended by the manufacturer; or c. During periods in which ISO New England (ISO-NE) declares the implementation of Action 12 of ISO-NE Operating Procedure 4, *Action During a Capacity Deficiency*.	EU03	Env-A 101.661
23	*Fire Pump Operation* Fire pump operation shall be limited to: 1. 100 hours for maintenance and readiness checks during any consecutive 12-month period; and 2. 500 hours total during any consecutive 12-month period.	EU03	Env-A 618 Env-A 619 40 CFR 60.4211(e) (NSPS Subpart IIII) *More stringent than* Env-A 1211.01(j)(1)

[9] Compliance with the visible emission standard for EU03 shall be determined using 40 CFR 60, Appendix A, Method 9, upon request by the Division.

Table 5 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Unit**	**Regulatory Basis**
24	*Pollution Control Equipment Operation* Operate all pollution control equipment in accordance with the Pollution Control Equipment Operating Plan required in Table 6 Item 20.	PCE01	Env-A 604.01
25	*24-hour and Annual Ambient Air Limit* The emissions of any Regulated Toxic Air Pollutant (RTAP) shall not cause an exceedance of its associated 24-hour or annual Ambient Air Limit (AAL) as set forth in Env-A 1450.01, *Table Containing the List Naming All Regulated Toxic Air Pollutants*. Compliance was demonstrated at the time of permit issuance as described in the Division's Preliminary Determination for application #09-0285. The source must update the compliance demonstration using one of the methods provided in Env-A 1405 if: a. There is a revision to the list of RTAPs lowering the AAL for any RTAP emitted from the Facility; b. The amount of any RTAP emitted is greater than the amount that was evaluated in the Application Review Summary (e.g., use of a cooling water treatment chemical will increase); c. An RTAP that was not evaluated in the Preliminary Determination will be emitted (e.g., a new cooling water treatment chemical will be used); or d. Stack conditions (e.g. air flow rate) change.	Facility-wide	Env-A 1400
26	*Revisions of the List of RTAPs* In accordance with RSA 125-I:5 IV, if the Division revises the list of RTAPs or their respective AALs or classifications under RSA 125-I:4, II and III, and as a result of such revision the Owner or Operator is required to obtain or modify the permit under the provisions of RSA 125-I or RSA 125-C, the Owner or Operator shall have 90 days following publication of notice of such final revision in the New Hampshire Rulemaking Register to file a complete application for such permit or permit modification.	Facility-wide	Env-A 1404.02

Table 5 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Unit**	**Regulatory Basis**
27	*Relaxation of PSD Opt-Out Requirements* At such time that a particular source or modification becomes a major PSD source or major modification solely by virtue of a relaxation in any enforceable limitation on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of 40 CFR 52.21 (j) through (s) shall apply to the source or modification as though construction had not yet commenced on the source or modification.	Facility-wide	40 CFR 52.21(r)(4)
28	*Accidental Release Program Requirements* The quantities of regulated chemicals[10] stored at the facility are less than the applicable threshold quantities established in 40 CFR 68.130. The facility is subject to the Purpose and General Duty clause of the 1990 Clean Air Act, Section 112(r)(1). General Duty includes the following responsibilities: a. Identify potential hazards which result from such releases using appropriate hazard assessment techniques; b. Design and maintain a safe facility; c. Take steps necessary to prevent releases; and d. Minimize the consequences of accidental releases that do occur.	Facility-wide	CAAA 112(r)(1)
29	*Title V Permit Application* Submit an application for a Title V Permit to Operate to the Division within 12 months of commencing operation.[11]	Facility-wide	Env-A 609.07(a)(2)
30	*Acid Rain Permit Application* Submit to the Division at least 12 months prior to commencing operation: a. An application for an Acid Rain Permit; and, b. an application for amendment to this permit, if necessary to incorporate Acid Rain requirements.	EU01	40 CFR 72.30(b)(2)(ii) (Acid Rain)

[10] LBB will use 19% aqueous ammonia solution in the SCR system. Section 112(r) applies only if the concentration of ammonia is 20% or greater.

[11] Commencing operation shall be same as “initial startup” as defined in the document *Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards* (EPA-68-01-4143), where "initial startup” is the first time steam is produced by the boiler and used to produce heat or hot water, to run process equipment, or to produce electricity, defined as the first time that the facility transmits electricity onto the grid for sale.

VII. Monitoring and Testing Requirements

The Owner or Operator shall be subject to the monitoring and testing requirements as contained in Table 6:

Table 6 - Monitoring and Testing Requirements

Item #	Parameter	Method of Compliance	Frequency	Applicable Unit	Regulatory Basis
1	To be determined	When conditions warrant, the Division may require the Owner or Operator to conduct stack testing in accordance with USEPA or other Division-approved methods.	Upon request by the Division	Facility Wide	RSA 125-C:6, XI
2	Particulate Matter & Opacity	Conduct stack testing for: a. PM, PM_{10}, $PM_{2.5}$ and opacity to determine compliance with the PM and opacity emission limits in Table 5 Items 2 and 17; and b. Condensable PM to confirm emission rates evaluated during review of application 09-0285	Within 60 days after achieving the maximum production rate and not later than 180 days after initial startup[12]	EU01	40 CFR 60.46b(d) NSPS Subpart Db & 40 CFR 60.8 Subpart A
3	SO_2, H_2SO_4, Beryllium, HCl, Mercury & VOCs	Conduct stack testing for: a. SO_2, H_2SO_4, beryllium, HCl, and mercury to determine compliance with the emission limitations in Table 5 Items 4 through 8; and b. VOCs to confirm emission rates evaluated during review of application 09-0285.	Within 60 days after achieving the maximum production rate and not later than 180 days after initial startup	EU01	RSA 125-C:6, XI & 40 CFR 63 Subpart B (Case-by-Case MACT)
4	PM	Conduct stack testing for PM to determine compliance with the emission limits in Table 5 Item 15.	Within 60 days after achieving the maximum production rate and not later than 180 days after initial startup	EU02	RSA 125-C:6, XI

12 As defined in the document *Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards* (EPA-68-01-4143), "initial startup" is the first time steam is produced by the boiler and used to produce heat or hot water, to run process equipment, or to produce electricity.

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
5	General Stack Testing Requirements	Compliance testing shall be planned and carried out in accordance with the following schedule: a. A pre-test protocol shall be submitted to the Division at least 30 days prior to the commencement of testing The pre-test protocol shall contain the information specified in Env-A 802.04; b. In the event that the Owner or Operator is unable to conduct the performance test on the date specified in the notification provided pursuant to a. above, the Owner or Operator shall notify the Division and USEPA at least 7 days prior to the originally scheduled test; c. The Owner or Operator and any contractor retained by the Owner or Operator to conduct the test shall meet with a Division representative at least 15 days prior to the test date to finalize the details of the testing; d. A test report shall be submitted to the Division within 60 days after the completion of testing. The test report shall contain the information specified in Env-A 802.11(c); and	Initial performance test and subsequent testing	Facility-wide	Env-A 802 40 CFR 60.8 & 40 CFR 63 Subpart B (Case-by-Case MACT)
		e. The Owner or Operator shall be subject to fees for any initial performance testing and monitoring required by this permit which is observed by the Division and for its review of any subsequent compliance test reports.	Initial performance tests		Env-A 704.02
6	General Stack Testing Requirements	*Operating Conditions During a Stack Test* Compliance testing shall be conducted under one of the following operating conditions: a. Between 90 and 100 percent, inclusive, of maximum production rate or rated capacity; b. A production rate at which maximum emissions occur; or c. At such operating conditions agreed upon during a pre-test meeting conducted pursuant to Env-A 802.05.	Initial performance test and subsequent testing	Facility-wide	Env-A 802.10 40 CFR 60.8 & 40 CFR 63 Subpart B (Case-by-Case MACT)

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
7	NOx, CO, and diluent gas CEMS	*NOx, CO, and diluent gas Continuous Emission Monitoring System* Install, calibrate, operate, and maintain CEMS for NOx, CO, and diluent gas (oxygen or carbon dioxide), which shall be used to determine compliance with NOx, CO, and emission limits established in Table 5 Items 1, 3, and 11, in accordance with the following: a. Install, calibrate, operate, and maintain each CEMS according to 40 CFR 60 Appendix B, and the CEMS & COMS Monitoring Plan developed in accordance with Table 6 Item 12; d. Operate the CEMS in accordance with the SSMP during periods of startup, shutdown, and malfunction; e. Conduct a performance evaluation for each CEMS in accordance with the requirements of 40 CFR 63.8 and 40 CFR 60 Appendix B f. Each CEMS must complete a minimum of one cycle of operation (sampling, analysis and data recording) for each successive 15-minute period; and g. Reduce the CEMS data in accordance with 40 CFR 63.8(g)(2).	Continuous	EU01	40 CFR 63 Subpart B (Case-by-Case MACT) 40 CFR 60.8 & Env-A 808
8	Ammonia slip	*Ammonia Continuous Emission Monitoring System* Install, calibrate, operate, and maintain CEMS for ammonia which shall be used to determine compliance with ammonia slip emission limitation in Table 5 Item 9, in accordance with the following: a. Install, calibrate, operate, and maintain the CEMS according the CEMS & COMS Monitoring Plan developed in accordance with Table 6 Item 12; d. Operate the CEMS in accordance with the SSMP during periods of startup, shutdown, and malfunction; e. Conduct a performance evaluation for the CEMS in accordance with the requirements of Env-A 808.08.	Continuous	EU01/ PCE02	Env-A 808

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
9	Opacity COMS	*Continuous Opacity Monitoring System* Install, calibrate, maintain, and operate a COMS, which shall be used to demonstrate compliance with the opacity limitation in Table 5 Item 17, in accordance with the following: a. Install, operate, and maintain the COMS according to of 40 CFR 60, Appendix B PS1 and the CEMS & COMS Monitoring Plan developed in accordance with Table 6 Item 12; c. Operate the COMS in accordance with the SSMP during periods of startup, shutdown, and malfunction; d. Conduct a performance evaluation of each COMS according to the requirements of 40 CFR 63.8 and 40 CFR 60, Appendix B PS1; e. Each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period; and f. Reduce COMS data as specified in 40 CFR 63.8(g)(2).	Continuously	EU01	40 CFR 60.48b(a) Appendix B & 40 CFR 63 Subpart B (Case-by-Case MACT)
10	Minimum Specifications for CEMS and COMS	The Owner or Operator shall ensure that each CEMS and COMS meets the following operating requirements: a. Each COMS shall average the opacity data to result in consecutive, non-overlapping 6-minute averages; b. Each CEMS average and record the data for each calendar hour; c. All CEMS and COMS shall include a means to display instantaneous values of percent opacity and gaseous emission concentrations and complete a minimum of one cycle of operation which shall include measurement, analyzing, and data recording for each successive 5-minute period for systems measuring gaseous emissions and each 10-second period for systems measuring opacity, unless a longer time period is approved in accordance with Env-A 809; and d. A valid hour of CEM emissions data means a minimum of 42 minutes of CEMS readings taken in any calendar hour, during which the CEMS is not in an out of control period and the facility is in operation.	N/A	EU01	Env-A 808.03

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
11	Stack Volumetric Flow	a. Install, calibrate, and maintain a stack volumetric flow measuring device according to the following requirements: 1. All differential pressure flow monitors shall have an automatic blow-back purge system installed, and in wet stack conditions, shall have the capability of drainage of the sensing lines; and 2. The stack flow monitoring system shall have the capability for manual calibration of the transducer while the system is on-line and for a zero check. b. Alternatives to in-stack flow monitoring devices for determination of stack volumetric flow rate may be used if the Owner or Operator provides the Division with technical justification that the alternative can meet the same requirements for data availability, data accuracy, and quality assurance as an in-stack device.	Continuously	EU01	Env-A 808.03(d)

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
12	CEMS & COMS Monitoring Plan	Prepare and submit to the Division a CEMS and COMS Monitoring Plan which includes the following: a. A complete description of the emission monitoring system including, but not limited to: 1. The identity of the CEM system vendor, including the company name, address, and telephone number; 2. The identity of the manufacturer, model number, measurement method employed, and range of each of the major components or analyzers being used; 3. A description of the sample gas conditioning system; 4. A description and diagram showing the location of the monitoring system, including sampling probes, sample lines, conditioning system, analyzers, and data acquisition system; and 5. A description of the data acquisition system, including sampling frequency, and data averaging methods; b. The mathematical equations used by the data acquisition system, including the value and derivation of any constants, to calculate the emissions in terms of the applicable emission standards; c. An example of the data reporting format; d. A description of the instrument calibration methods, including the frequency of calibration checks and manual calibrations, and path of the sample gas through the system; e. The means used by the data acquisition system of determining and reporting periods of excess emissions, monitor downtime, and out-of-control periods; and f. A description of the means used to provide for short-term and long-term emissions data storage.	Submit[13] to the Division at least 90 days prior to installation of any CEMS	EU01	Env-A 808.04

[13] Unless otherwise specified, all due dates listed in the permit mean that the required submittal must be received at the Division by the deadline.

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
13	CEM Performance Specification Testing	Conduct performance specification testing for a CEM system in accordance with the following: a. The performance specification requirements of 40 CFR 60, Appendix B or Division-approved requirements for units not covered by Appendix B (e.g., ammonia CEM) for each CEMS and COMS; b. For each COMS, the calibration error test specified in 40 CFR 60, Appendix B, Performance Specification 1, paragraph 7.1.4, shall be performed with the monitor installed on the stack or duct that is to be the permanent location for the monitor; c. All performance specification testing shall be conducted within 180 days of the CEMS or COMS initial startup; d. The Division shall be notified of the date or dates of the performance specification testing at least 30 days prior to the scheduled dates; and e. A written report summarizing the results of the testing shall be submitted to the Division within 30 days of the completion of the test.	As specified	EU01	Env-A 808.05
14	CEMS & COMS QA/QC Plan	Prepare and maintain a Quality Assurance/Quality Control (QA/QC) plan which covers each CEMS and COMS at the facility in accordance with the following: a. Review the QA/QC plan and all data generated by its implementation at least once each year; b. Revise or update the QA/QC plan, as necessary, based on the results of the annual review, by: 1. Documenting any changes made to the CEM or changes to any information provided in the monitoring plan; 2. Including a schedule of, and describing, all maintenance activities that are required by the CEM manufacturer or that might have an effect on the operation of the system; 3. Describing how the audits and testing required by Env-A 808 will be performed; and 4. Including examples of the reports that will be used to document the audits and tests required by Env-A 808.	Initial Submit to the Division within 30 days of completion of the CEMS/COMS Performance Specification testing required in Table 6 Item 13 Annual Submit results of annual review within 30 days of the annual review	EU01	Env-A 808.06

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
15	General Audit Requirements for all CEM Systems	Audit each CEMS in accordance with the following: a. Required quarterly CEMS audits shall be performed anytime during each calendar quarter, but successive quarterly audits shall occur no more than 4 months apart; b. Notify the Division at least 30 days prior to the performance of a Relative Accuracy Test Audit (RATA); c. Provide at least 2 weeks' notice prior to any other planned audit or test procedure; d. Submit to the Division a written summary report of the results of all required audits that were performed in that quarter within 30 calendar days following the end of each quarter, in accordance with the following: 1. For gaseous CEMS audits, the report format shall conform to that presented in 40 CFR 60, Appendix F, Procedure 1, section 7, or Division approved alternatives for units not covered by Appendix F (e.g., ammonia); and 2. For COMS audits, the report format shall conform to that presented in EPA-600/8-87-025, April 1992, "Technical Assistance Document: Performance Audit Procedures for Opacity Monitors".	Quarterly	EU01	Env-A 808.07
16	CEMS Audit Requirements	Perform audits for CEMS in accordance with procedures described in 40 CFR 60, Appendix F or Division approved alternatives for units not covered by Appendix F (e.g., ammonia), and Env-A 808.08.	Quarterly	EU01	Env-A 808.08
17	COMS Audit Requirements	Perform audits for COMS in accordance with procedures described in Env-A 808.09 and 40 CFR 60, Appendix B, Specification 1.	Quarterly	EU01	Env-A 808.09
18	CEMS & COMS Data Availability Requirements	a. Each CEMS shall operate at all times during the operation of the source, except for periods of CEMS breakdown, repairs, calibration checks, preventive maintenance, and zero/span adjustments; b. The percentage CEMS and COMS data availability shall be maintained at a minimum of 90% on a calendar quarter basis; and c. The percentage CEMS and COMS data availability shall be maintained at a minimum of 75% for any calendar month.	N/A	EU01	Env-A 808.10

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
19	Data Availability Calculations	The Owner or Operator shall use the following equation for calculating percentage data availability: $\textit{Percentage Data Availability} = \frac{(VH + CalDT) \times 100}{(OH - AH)}$ Where: VH = Number of valid hours of CEM data in a given time period for which the data availability is being calculated when the plant is in operation; CalDT = Number of hours, not to exceed one hour per day, during facility operation when the CEM is not operating due to the performance of the daily CEM calibrations as required in 40 CFR 60, Appendix F; OH = Number of facility operating hours during a given time period for which the data availability is being calculated; and AH = Number of hours during facility operation when the performance of quarterly audits as required by those procedures specified in Env A 808.08 or Env-A 808.09, as applicable, require that the CEM be taken out of service in order to conduct the audit.	As specified	EU01	Env-A 808.10

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
20	Pollution Control Equipment Operating Plan	Develop and submit to the Division for review and approval a Pollution Control Equipment Operating Plan which contains the following elements, at a minimum for each control device: a. Type, manufacturer, model, and serial number; b. Pollutants controlled; c. Description of the control device and how it operates in the process; d. The capture efficiency, control efficiency, and their method of determination; e. The operational parameters that are monitored (e.g., temperature, pressure drop, flowrate etc.); f. For each operational parameter in e. above, the range indicative of proper operation of the control device during normal operation, startup, and shutdown; g. For catalytic control devices: 1. Method and frequency of catalyst activity monitoring; and 2. The frequency of catalyst replacement. h. The methods and frequency of operational parameter data monitoring and recordkeeping; i. Operational parameter setpoints and alarms; j. Planned and actual operator responses to malfunctions of the device; k. Procedures for operation of the device; l. Frequency and type of scheduled maintenance and calibration; and m. Data sufficient to demonstrate the actual performance of the device that will be periodically submitted to the Division in the Pollution Control Equipment Operation Report required in Table 8 Item 14.	Submit to the Division at least 90 days prior to operation of any control device	PCE01 – PCE04	RSA 125-C:6, XI & 40 CFR 63 Subpart B (Case-by-Case MACT)
21	Startup/ Shutdown Malfunction Plan	Develop and submit to the Division for review and approval a Startup/Shutdown Malfunction Plan which contains the following elements, at a minimum: a. Procedures for operating and maintaining the source during periods of startup, shutdown, and malfunction; b. A program of corrective actions for malfunctioning processes, air pollution control equipment, and monitoring equipment; and c. NO_x, and CO emission limitations for startup and shutdown of the biomass boiler (EU01).	Submit to the Division within 12 months of commencing operation	EU01, EU02 & PCE01-PCE04	Env-A 618 Env-A 619 & 40 CFR 63 Subpart B (Case-by-Case MACT)

Table 6 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
22	Hours of Operation	The fire pump shall be equipped with a non-resettable hour meter.	Continuous	EU03	40 CFR 60.4209(a) (Subpart IIII)
23	Sulfur Content of Liquid Fuels	Conduct testing in accordance with appropriate ASTM test methods or retain delivery tickets in accordance with Table 7 Item 8 in order to demonstrate compliance with the sulfur content limitation provisions specified in this permit for liquid fuels.	For each delivery of fuel oil/diesel to the facility	Facility-wide	Env-A 806.02 & Env-A 806.05

VIII. Recordkeeping Requirements

The Owner or Operator shall be subject to the recordkeeping requirements identified in Table 7:

Table 7 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
1	*Record Retention and Availability* Maintain all records required by this permit on file. These records shall be available for review by the Division upon request.	Retain for a minimum of 5 years	Facility-wide	40 CFR 60.7 (f), 40 CFR 60.49b(o), Env-A 902.01(a) & Env-A 903.04
2	*NSPS Startup, Shutdown, Malfunction Records* Maintain records of the occurrence and duration of any: a. Startup, shutdown, or malfunction in the operation of the affected facility; b. Any malfunction of the air pollution control equipment; and c. Any periods during which a continuous monitoring system or monitoring device is inoperative.	Each occurrence	EU01	40 CFR 60.7 (b)
3	*General Recordkeeping Requirements for Combustion Devices* Maintain the following records of fuel characteristics and utilization for the fuel used in the each combustion device: a. Type (e.g. wood chips, No. 2 fuel oil) and amount of fuel burned; and b. Hours of operation.	Daily, Monthly, & 12-month rolling	EU01 & EU03	Env-A 903.03 & 40 CFR 60.49b(d)
4	*Fuel Annual Capacity Factors* Maintain records of the annual capacity factor individually for fuel oil and wood.	Monthly & 12-month rolling	EU01	40 CFR 60.49b(d)
5	*Opacity NSPS Subpart Db Recordkeeping Requirement* Maintain records of opacity	Continuously	EU01	40 CFR 60.49b(f)

Table 7 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
6	*Fire Pump* Maintain the following records of fuel characteristics and utilization for the fuel used in the each combustion device: a. Type (e.g. diesel fuel oil) and amount of fuel burned; and b. Hours of operation for maintenance & readiness testing; and c. Hours of operation for emergency use.	Monthly	EU03	Env-A 903.03 & 40 CFR 60.4211(e) NSPS Subpart IIII
7	*NSPS Recordkeeping Requirements for Internal Combustion Engines* Maintain documentation from the engine manufacturer certifying that the engine complies with the applicable emissions standards stated in 40 CFR 60 Subpart IIII.	Maintain up-to-date data	EU03	40 CFR 60.4211 (Subpart IIII)
8	*Liquid Fuel Oil Recordkeeping Requirements* Maintain fuel delivery tickets that contain the following information: a. The date of delivery; b. The quantity of delivery;	For each delivery of fuel oil to the facility	EU01 & EU03	Env-A 806.05
	c. The name, address and telephone number of the company making the delivery; and d. The maximum weight percentage of sulfur or a written statement from the fuel supplier that the sulfur content of the fuel as delivered does not exceed standards listed in this permit for that fuel	Whenever there is a change in fuel supplier but at least annually		
9	*VOC Emission Statements Recordkeeping Requirements* If the actual annual VOC emissions from all permitted devices located at the Facility are greater than or equal to 10 tpy, then maintain records of the following information: a. Identification of each VOC-emitting process or device; b. The operating schedule during the high ozone season (June 1 through August 31) for each VOC-emitting process or device identified in a. above, including: 1. Typical hours of operation per day; and 2. Typical days of operation per calendar month. c. The following VOC emission data from all VOC-emitting processes or devices identified in Table 7 Item 9.a above, including: 1. Actual VOC emissions for: 2. The calendar year, in tons; and 3. A typical high ozone season day during that calendar year, in pounds per day; and d. The emission factors and the origin of the emission factors used to calculate the VOC emissions.	Maintain up-to-date data	Facility-wide	Env-A 904.02

Table 7 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
10	*General NOx Recordkeeping Requirements* Maintain records of the following information: a. Identification of each fuel burning device; b. Operating schedule during the high ozone season (June 1 through August 31) for each fuel burning device identified in Table 7 Item 10.a, above, including: 1. Typical hours of operation per day; 2. Typical days of operation per calendar month; 3. Number of weeks of operation; 4. Type and amount of each fuel burned; 5. Heat input rate in MMBtu/hr; 6. Actual NOx emissions for the calendar year and a typical high ozone day during that calendar year; and 7. Emission factors and the origin of the emission factors used to calculate the NOx emissions.	Maintain up-to-date data	EU01 & EU03	Env-A 905.02
11	*Recordkeeping Requirements for Add-On NOx Control Equipment* Maintain records of the following information: a. Air pollution control device identification number, type, model number, and manufacturer; b. Installation date; c. Unit(s) controlled; d. Type and location of the capture system, capture efficiency percent, and method of determination; e. Information as to whether the air pollution control device is always in operation when the fuel burning device it is serving is in operation; f. Destruction or removal efficiency of the air pollution control equipment, including the following information: 1. Destruction or removal efficiency, in percent; 2. Date tested; 3. Emission test results; and g. Method of determining destruction or removal efficiency, if not tested.	Maintain up-to-date data	PCE02	Env-A 905.03
12	*Pollution Control Equipment Operating Plan* Maintain the following: a. The Pollution Control Equipment Operating Plan required in Table 6 Item 20; and b. Records of all data required to be recorded in accordance with the Pollution Control Equipment Operating Plan.	a. Maintain up-to-date plan b. As specified in the plan	PCE01-PCE04	Env-A 906
13	*Startup/Shutdown Malfunction Plan* Maintain records of the following: a. The Startup/Shutdown Malfunction Plan required in Table 6 Item 21; and	a. Maintain up-to-date plan	EU01, EU02 & PCE01-PCE04	Env-A 906

Table 7 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
	b. Records of all data required to be recorded in accordance with the Startup/Shutdown Malfunction Plan.	As specified in the plan		
14	*CEMS & COMS Monitoring and QA/QC Plan* Maintain the CEMS & COMS Monitoring and QA/QC Plan as required in Table 6 Items 12 and 14, including all data required to be recorded in accordance with the plan.	Maintain up-to-date plans	Facility-wide	Env-A 808
15	*Regulated Toxic Air Pollutants* Maintain records documenting compliance with Env-A 1400.	Maintain up-to-date data	Facility-wide	Env-A 902.01
16	*Permit Deviation Recordkeeping Requirements* Record permit deviations in accordance with Condition XVI.	As noted in Condition XVI	Facility-wide	Env-A 911.03

IX. Reporting Requirements

The Owner or Operator shall be subject to the reporting requirements identified in Table 8 below. All emissions data submitted to the Division shall be available to the public. Claims of confidentiality for any other information required to be submitted to the Division pursuant to this permit shall be made at the time of submission in accordance with Env-A 103, *Claims of Confidentiality*.

Table 8 - Reporting Requirements

Item #	Requirement	Frequency	Applicable Unit	Regulatory Basis
1	*Annual Emissions Report* Submit an annual emissions report which shall include the following information: a. Actual calendar year emissions from each emission unit of NO_x, CO, SO_2, TSP, PM10, and VOCs, HAPs (speciated by individual HAP), and RTAPs (speciated by individual RTAP); b. The methods used in calculating such emissions in accordance with Env-A 705.02, *Determination of Actual Emissions for Use in Calculating Emission-Based Fees*; and c. All monthly and 12-month rolling information recorded in accordance with Table 7 Items 3 and 6.	Annually (received by the Division no later than April 15th of the following year)	EU01, EU02 & EU03	Env-A 907.01
2	*NSPS and MACT Notification Requirements* Submit notification of the initial startup, which shall include: a. The date construction is commenced, postmarked no later than 30 days after such date; b. The actual date of initial startup postmarked within 15 days of such date, which shall also include the following information: 1. The design heat input capacity of the boiler; 2. Identification of fuels to be combusted in the boiler; 3. A copy of the federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels; and 4. The annual capacity factor at which the Owner or Operator anticipates operating the facility based on all fuels combined and each individual fuel. c. Notification of the date upon which demonstration of the continuous monitoring systems performance commences in accordance with 40 CFR 60.13(c), postmarked not less than 30 days prior to such date.	As specified	EU01	40 CFR 60.7(a) & 40 CFR 60.49b(a) & 40 CFR 63 Subpart B (Case-by-Case MACT

Table 8 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
3	*Opacity Compliance Determination During Performance Tests* If applicable, submit a notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 instead of Method 9 observation data for the Boiler.	Postmarked not less than 30 days prior to the date of the performance test	EU01	40 CFR 60.11(e)(5)
4	*VOC Emission Statements Reporting Requirements* If the actual annual VOC emissions from all permitted devices located at the Facility are greater than or equal to 10 tpy, then include the following information with the annual emission report: a. Facility information, including: 1. Source name; 2. Standard Industrial Classification (SIC) code; 3. North American Industrial Classification System (NAICS) code; 4. Physical and mailing addresses; and b. A breakdown of VOC emissions reported pursuant to Table 8 Item 1 by month; and c. All data recorded pursuant to Table 7 Item 9.	Annually (received by the Division no later than April 15th of the following year)	EU01 & EU03	Env-A 908.03
5	*NOx Emission Statements Reporting Requirements* If the actual annual NOx emissions from all permitted devices located at the Facility are greater than or equal to 10 tpy, then include the following information with the annual emission report: a. A breakdown of NO_x emissions reported pursuant to Table 8 Item 1 by month; and b. All data recorded in accordance with Table 7 Item 10.	Annually (received by the Division no later than April 15th of the following year)	EU01 & EU03	Env-A 909.03
6	*NSPS Performance Test Results for PM* The Owner or Operator shall submit the PM emissions test data from the initial performance test and from the performance evaluation of the COMS using the applicable performance specifications in 40 CFR 60 Appendix B to EPA and the Division.	Within 60 days of completing the performance tests	EU01	40 CFR 60.49b(b) & 40 CFR 60.8(a)
7	*NSPS Semi-annual Excess Emissions Reports for Opacity* Submit excess emissions reports for any excess emissions that occurred during the reporting period. For the purpose of 40 CFR 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the NSPS standard of 20%.	Postmarked within 30 days of the end of the 6-month reporting period	EU01	40 CFR 60.49b(h) & (w)

Table 8 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
8	<u>*Quarterly Emission Reports*</u> The Owner or Operator shall submit to the Division quarterly reports containing the following information: a. The information specified in 40 CFR 60.7(c); b. Excess emission data recorded by the CEM system, including the following: 1. The date and time of the beginning and ending of each of excess emissions; 2. The magnitude of each excess emission; 3. The specific cause of the excess emission; and 4. The corrective action taken; c. If no excess emissions have occurred, a statement to that effect; d. For gaseous emission monitoring systems, the daily averages of the measurements made and emissions rates calculated. e. A statement as to whether the CEM system was inoperative, repaired, or adjusted during the reporting period; f. If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: 1. The date and time of the beginning and ending of each period when the CEM was inoperative; 2. The reason why the CEM was not operating; 3. The corrective action taken; and 4. The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or pollutant analyzer in the CEM system; g. For all "out of control periods" as defined in Env-A 808.01(g) and 40 CFR 60, Appendix F, the following information: 1. The times beginning and ending the out of control period; 2. The reason for the out of control period; and 3. The corrective action taken; h. The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating; i. When calibration gas is used, the following information: 1. Calibration gas concentration; 2. If a gas bottle was changed during the quarter: i. The date of the calibration gas bottle change; ii. The gas bottle concentration before the change; iii. The gas bottle concentration after the change; and 3. The expiration date for all calibration gas bottles used.	Within 30 calendar days after the end of the calendar quarter	EU01	Env-A 808.11, Env-A 808.12

Table 8 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
9	*Option to Use Electronic Reporting for NSPS Subpart Db* The Owner or Operator of an affected facility may submit electronic quarterly reports for opacity in lieu of submitting the written reports required under 40 CFR 60.49b(h) (i.e., Table 8 Item 7 above). The format of each quarterly electronic report shall be coordinated with the Division. The electronic report(s) shall be accompanied by a certification statement from the Owner or Operator, indicating whether compliance with the applicable emission standards and minimum data requirements specified in this permit was achieved during the reporting period.	Within 30 days of the end of the calendar quarter	EU01	40 CFR 60.49b(v)
10	*Annual Compliance Certification* Submit an annual compliance certification to the Division and USEPA which includes the following information for each and every requirement and condition of the facilities effective permit(s): a. The particular permit condition or item number that references each requirement, and a brief summary of the requirement; b. The compliance status with respect to the requirement and whether during the year compliance with the requirement was continuous, intermittent, not achieved, or not applicable; c. The method(s) used to determine compliance, such as monitoring, record keeping, or test methods; d. The frequency, either continuous or intermittent, of the method(s) used to determine compliance; e. If compliance was not continuous, a description of each permit deviation; and f. Any additional information required in order for the Division to determine the compliance status of the source.	No later than April 15 of the year following the calendar year covered by the report	Facility-wide	Env-A 907.04(a)
11	*Semi-annual Permit Deviation and Monitoring Report* Submit a semi-annual permit deviation and monitoring report, which contains: a. Summaries of the pertinent data that demonstrate the source's compliance status with all monitoring and testing requirements contained in this permit; b. Evidence that the required data is being recorded and maintained; and c. A summary of all permit deviations recorded pursuant to Condition XVI of this Permit that occurred during the reporting period.	Semi-annually by July 31st and January 31st of each calendar year.	Facility-wide	Env-A 907.04(b) & Env-A 911.05

Table 8 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
12	*CEMS & COMS Monitoring and QA/QC Plan Updates* Submit either a: a. Written certification that the Owner or Operator will continue to implement the existing QA/QC plan; or b. Written description of any changes to the plan, including the reason for the changes.	Annually	EU01	Env-A 808.06(a)(6)
13	*Pollution Control Equipment Operating Plan Updates* Submit either a: a. Written certification that the Owner or Operator will continue to implement the existing Pollution Control Equipment Operating Plan; or b. Written description of any changes to the plan, including the reason for the changes.	Annually	EU01, EU02 & PCE01-PCE04	Env-A 910
14	*Pollution Control Equipment Operation Report* Submit a report of data required to be reported by the Pollution Control Equipment Operating Plan in accordance with Table 6 Item 20.m.	Annually	EU01, EU02 & PCE01-PCE04	Env-A 910
15	*Startup/Shutdown Malfunction Plan Updates* Submit either a: a. Written certification that the Owner or Operator will continue to implement the existing Startup/Shutdown Malfunction Plan; or b. Written description of any changes to the plan, including the reason for the changes.	Annually	EU01, EU02 & PCE01-PCE04	Env-A 618 Env-A 619 & 40 CFR 63 Subpart B (Case-by-Case MACT
16	*Permit Deviation Reporting Requirements* Report permit deviations in accordance with Condition XVI.	As noted in Condition XVI	Facility-wide	Env-A 911.04
17	*Emission Based Fees* Pay emission-based fees in accordance with Condition XIX.	Annually (received by the Division no later than April 15th of the following year)	EU01, EU02 & EU03	Env-A 700

General Temporary/NSR/PSD Permit Conditions

X. Temporary Permit Reissuance Procedures

Pursuant to Env-A 607.02(b), for the reissuance of a temporary permit, an application shall be considered timely if it is received by the Division at least 90 days prior to the designated expiration date of the temporary permit.

XI. Timely Application

Pursuant to Env-A 609.07(a)(2), for an initial Title V Operating Permit, an application shall be considered timely if it is received at the Division within 12 months of commencing operation.

XII. Permit Expiration

Pursuant to Env-A 607.08(c), the expiration of a temporary permit shall terminate the Owner or Operator's right to construct or operate a new or modified source or device pursuant to the permit, unless a timely and complete application for a state permit to operate, title V operating permit, or an amendment thereto, has been received by the Division. Upon the submittal of a timely and complete application for any of the foregoing permits, the right to construct shall continue, under the terms and conditions of the expired temporary permit, pending the Division's decision on the application.

XIII. Application Shield

A. Pursuant to Env-A 607.10(a), if an applicant submits a timely application that has been deemed complete by the Division for the reissuance of a temporary permit or the issuance of an initial state permit to operate, the failure to have a current and valid temporary permit shall not be considered a violation of RSA 125-C:11,I or Env-A 607.01 unless and until the Division takes final action on the application by denying the requested reissuance of a temporary permit or issuance of a state permit to operate.

B. Pursuant to Env-A 607.10(b), if the Division deems an application complete, but requests additional information pursuant to Env-A 607.06(b), the protection granted in Env-A 607.10(a) shall cease to apply when the applicant fails to submit in writing such additional requested information by the deadline specified in the request.

XIV. Permit Amendments

A. Env-A 612.01, *Administrative Permit Amendments*:

1. An administrative permit amendment includes the following:
   a. Corrects typographical errors;
   b. Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;
   c. Requires more frequent monitoring or reporting; or
   d. Allows for a change in ownership or operational control of a source provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new Permittee has been submitted to the Division.
2. The Owner or Operator may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

B. Env-A 612.03, *Minor Permit Amendments: Temporary Permits and State Permits to Operate*:

1. The Owner or Operator shall submit to the Division a request for a minor permit amendment for any proposed change to any of the conditions contained in this permit which will not result in an increase in the amount of a specific air pollutant currently emitted by the emission units listed in Condition III and will not result in the emission of any air pollutant not emitted by the emission unit.
2. The request for a minor permit amendment shall be in the form of a letter to the Division and shall include the following:
   a. A description of the proposed change; and
   b. A description of any new applicable requirements that will apply if the change occurs.
3. The Owner or Operator may implement the proposed change immediately upon filing a request for the minor permit amendment.

C. Env-A 612.04, *Significant Permit Amendments: Temporary Permits and State Permits to Operate*:

1. The Owner or Operator shall submit a written request for a permit amendment to the Division at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the emission units covered by this permit which increases the amount of a specific air pollutant currently emitted by such emission unit or which results in the emission of any regulated air pollutant currently not emitted by such emission unit.
2. A request for a significant permit amendment shall include the following:
   a. A complete application form, as described in Env-A 1703 through Env-A 1708, as applicable;
   b. A description of:
      i. The proposed change;
      ii. The emissions resulting from the change; and
      iii. Any new applicable requirements that will apply if the change occurs; and
      iv. Where air pollution dispersion modeling is required for a device pursuant to Env-A 606.02, the information required pursuant to Env-A 606.03.
3. The Owner or Operator shall not implement the proposed change until the Division issues the amended permit.

XV. Temporary/NSR/PSD Permit Suspension, Revocation or Nullification

A. Pursuant to RSA 125-C:13, the NHDES Commissioner may suspend or revoke any final permit issued hereunder if, following a hearing, the Commissioner determines that:

1. The Owner or Operator has committed a violation of any applicable statute or state requirement found in the New Hampshire Rules Governing the Control of Air Pollution, order or permit condition in force and applicable to it; or
2. The emissions from any device to which this Permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.

B. The Commissioner shall nullify any Permit if, following a hearing in accordance with RSA 541-A:30, II, a finding is made that the Permit was issued in whole or in part based upon any information proven to be intentionally false or misleading.

XVI. Permit Deviation Recordkeeping and Reporting Requirements

A. The Owner or Operator shall be subject to the permit deviation recordkeeping and reporting requirements in Table 9 below, where permit deviation and excess emission are defined as follows:

Env-A 101, *Definitions*:

1. A *permit deviation* is any occurrence that results in an excursion from any emission limitation, operating condition, or work practice standard as specified in either a Title V permit, state permit to operate, temporary permit or general state permit issued by the Division.
2. An *excess emission* is an air emission rate that exceeds any applicable emission limitation.

Table 9 - Permit Deviation Recordkeeping and Reporting Requirements			
Item #	**Requirement**	**Frequency**	**Regulatory Basis**
1	<u>*Permit Deviation Recordkeeping*</u> In the event of a permit deviation, the Owner or Operator shall: a.. Investigate and take corrective action immediately upon discovery of the permit deviation to restore the affected device, process, or air pollution control equipment to within allowable permit levels; and b. Record the following information: 1. The permit deviation; 2. The probable cause of the permit deviation; 3. The date of the occurrence; 4. The duration; 5. The specific device that contributed to the permit deviation; and 6. Any corrective or preventative measures taken.	Each permit deviation	Env-A 911.03

Table 9 - Permit Deviation Recordkeeping and Reporting Requirements			
Item #	**Requirement**	**Frequency**	**Regulatory Basis**
2	*Permit Deviation Reporting – No Excess Emissions* If the permit deviation does not cause excess emissions, but continues for a period greater than nine consecutive days, notify the Division by e-mail (pdeviations@des.nh.gov), telephone (603-271-1370) or fax (603-271-1381), of the subsequent corrective actions to be taken.	On the tenth day of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the Division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday	Env-A 911.04
3	*Permit Deviation Reporting – Excess Emissions* In the event of a permit deviation that causes excess emissions: a. Notify the Division of the permit deviation and excess emissions by e-mail, telephone or fax,; and b. Submit a written report to the Division reported in Item a, above. The written report shall include the following information: 1. Facility name; 2. Facility address; 3. Name of the responsible official employed at the facility; 4. Facility telephone number; 5. Date(s) of the occurrence; 6. Time of the occurrence; 7. Description of the permit deviation; 8. The probable cause of the permit deviation; 9. Corrective action taken to date; 10. Preventative measures taken to prevent future occurrences; and 11. Date and time that the device, process, or air pollution control equipment returned to operation in compliance with an enforceable emission limitation, or operating condition; 12. The specific device, process or air pollution control equipment that contributed to the permit deviation; 13. The type and quantity of excess emissions emitted to the atmosphere due to the permit deviation; and 14. The calculation or estimation used to quantify the excess emissions.	*Notification*: Within twenty-four (24) hours of discovery of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the Division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday *Written Report:* Within ten (10) days of discovery of the permit deviation	Env-A 911.04
4	*Data Availability Permit Deviations* In the event of a permit deviation caused by a failure to comply with the data availability requirements of Env-A 800: a. Notify the Division of the permit deviation by e-mail, telephone or fax,; and b. Report the permit deviation to the Division, as part of the emissions report required pursuant to Table 8 Item 8.	*Notification*: Within 10 days of discovery of the permit deviation *Written Report:* See Table 8 Item 8	Env-A 911.04(c)

XVII. Inspection and Entry

EPA and Division personnel shall be granted access to the facility covered by this Permit, in accordance with RSA 125-C:6,VII, for the purposes of: inspecting the proposed or permitted site; investigating a complaint; and assuring compliance with any applicable requirement or state requirement found in the NH Rules Governing the Control of Air Pollution and/or conditions of any permit issued pursuant to Env-A 600.

XVIII. Reports

All reports submitted to the Division (except those submitted as emission-based fees as outlined in Section XIX of this Permit) shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive, P.O. Box 95
Concord, NH 03302-0095
ATTN: Administrator, Compliance Bureau

All reports submitted to USEPA shall be submitted to the following address:

EPA-New England, Region 1
5 Post Office Sq. Suite 100
Mail Code OEP05-2
Boston, MA 02109-3912

XIX. Emission-Based Fee Requirements

A. Env-A 705.01, *Emission-based Fees*: The Owner or Operator shall pay to the Division each year an emission-based fee for emissions from the emission units listed in Condition III.

B. Env-A 705.02, *Determination of Actual Emissions for use in Calculating of Emission-based Fees*: The Owner or Operator shall determine the total actual annual emissions from the emission units listed in Condition III for each calendar year in accordance with the methods specified in Env-A 616, *Determination of Actual Emissions*..

C. Env-A 705.03, *Calculation of Emission-based Fees*: The Owner or Operator shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT$$

where:
FEE = The annual emission-based fee for each calendar year as specified in Env-A 705;
E = Total actual emissions as determined pursuant to Condition XIX.B.; and
DPT = The dollar per ton fee the Division has specified in Env-A 705.03(e)[14].

D. Env-A 705.04, *Payment of Emission-based Fee*: The Owner or Operator shall submit, to the Division, payment of the emission-based fee by April 15th for emissions during the previous calendar year. For example, the fees for calendar year 2010 shall be submitted on or before April 15, 2011.

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14 For additional information on emission-based fees, visit the NHDES website at http://des.nh.gov/ard/whatfees.htm.

XX. Emission Offset Requirements

The Owner or Operator shall prior to commencing operation demonstrate that NOx offsets have been obtained in a ratio of 1.15 to 1.0. Such emission offsets shall be real, surplus, quantifiable, permanent and federally enforceable and shall be certified by the Division in accordance with all applicable state and federal regulations.