State of New Hampshire
Department of Environmental Services
Air Resources Division

Temporary Permit

Permit No: TP-B-0533
Date Issued: September 12, 2007

This certifies that:

Bridgewater Power Company, Inc.
P.O. Box 678
Ashland, NH 03217-0678

has been granted a Temporary Permit for a:

Wood-fired Boiler with Selective Non-Catalytic Reduction (SNCR) & Regenerative Selective Catalytic Reduction (RSCR) Systems and Cooling Pond

at the following facility and location:

Bridgewater Power Company, Inc.
Routes 3 and 25
Bridgewater, NH
Facility ID Number: 3300900021
Application Number: FY07-0091

which includes devices that emit air pollutants into the ambient air as set forth in the permit application filed with the New Hampshire Department of Environmental Services, Air Resources Division (Division) on **May 16, 2007** and supplemental information filed on **July 20, 2007**, in accordance with RSA 125-C of the New Hampshire Laws. Request for permit renewal 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 **March 31, 2009**.

Director
Air Resources Division

Abbreviations and Acronyms

AAL	Ambient Air Limit
acf	actual cubic foot
ags	above ground surface
ASTM	American Society of Testing and Materials
Btu	British thermal units
CAAA	Clean Air Act Amendments (1990)
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstracts Service
CEM	Continuous Emissions Monitoring
CERMS	Continuous Emission Rate Monitoring System
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
DER	Discrete Emission Reduction
DES	New Hampshire Department of Environmental Services
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
ERC	Emission Reduction Credit
ft	foot or feet
ft3	cubic feet
gal	gallon
HAP	Hazardous Air Pollutant
hp	horsepower
hr	hour
kW	kilowatt
lb	pound
LPG	Liquified Petroleum Gas
MM	million
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standard
PM10	Particulate Matter < 10 microns
ppm	parts per million
ppmvd	parts per million by volume on a dry basis
psi	pounds per square inch
RACT	Reasonably Available Control Technology
RSA	Revised Statutes Annotated
RSCR	Regenerative Selective Catalytic Reduction
RTAP	Regulated Toxic Air Pollutant
scf	standard cubic foot
SO2	Sulfur Dioxide
TSP	Total Suspended Particulate
tpy	tons per consecutive 12-month period
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

I. Facility Description

Bridgewater Power Company, Inc. (Bridgewater) owns and operates a 15 MW net output power generation facility located on Routes 3 and 25 in Bridgewater, NH. The primary source of emissions at the facility is the Wood/Oil-Fired Boiler. The facility also operates an emergency diesel generator, a fire pump and a cooling pond. This facility is a major source for NOx and CO emissions and currently operates under Title V Operating Permit TV-OP-008 issued on March 22, 2007. The facility has proposed and has been granted approval through the issuance of this Temporary Permit to install a Selective Non-Catalytic Reduction (SNCR) System and Regenerative Selective Catalytic Reduction (RSCR) System to reduce emissions of nitrogen oxides from the Wood/Oil-Fired boiler.

II. Emission Unit Identification

This permit covers the devices identified in Table 1:

Table 1 - Emission Unit Identification

Emission Unit ID	Device Identification	Manufacturer Model Number Serial Number	Installation Date	Maximum Design Capacity and Fuel Type(s)[1]
EU1	Treebrook I Wood/Oil-fired Boiler	Foster Wheeler None 6770	1987	250 MMBtu/hr Equivalent to 165,000 lb steam/hr averaged over a 24-hour period at 850 degrees F, 695 psig, with a boiler efficiency of 68%, boiler feedwater temperature of 340 degrees F, and chip moisture content of 50% ▪ Whole tree chips and mill residue; ▪ Clean processed wood fuel[2]; ▪ No. 2 fuel oil; and ▪ On-spec used oil

III. Pollution Control Equipment Identification

Air pollution control equipment listed in Table 2 shall be operated at all times that the associated devices are operating in order to meet permit conditions.

Table 2 - Pollution Control Equipment Identification

Pollution Control Equipment ID	Description	Purpose	Emission Unit Controlled
PCE1	Multiclone	Control of large particulate matter	EU1

[1] The hourly fuel rates presented in Table 1 are set assuming a heating value of 140,000 Btu/gal for #2 fuel oil or On-spec oil, and 137,000 Btu/gal for diesel fuel.

[2] "Clean processed wood fuel" includes materials such as tree chips, stump grindings, pallet grindings, sawmill residue, wood pellets, and untreated furniture residue derived wood chips that exhibit fuel characteristics equivalent to "whole tree chips" and "sawdust" with respect to the ultimate and proximate analysis of the fuel, and shall not include such materials as telephone pole derived chips, railroad tie derived chips, construction or demolition wood waste derived chips, or painted or treated wood derived chips.

Table 2 - Pollution Control Equipment Identification			
Pollution Control Equipment ID	**Description**	**Purpose**	**Emission Unit Controlled**
PCE2	Gravel Bed Filter (GBF)	Control of fine particulate matter	EU1
PCE3	Baghouse for Gravel Bed Filter – Reverse Jet Pulse	Final removal of fine particulate matter from the Gravel Bed Filter	EU1
PCE4 (new)	Regenerative Selective Catalytic Reduction (RSCR) System	Control of nitrogen oxides	EU1
PCE5 (new)	Selective Non-Catalytic Reduction (SNCR) System	Control of nitrogen oxides	EU1

IV. Stack Criteria

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

Table 3 - Stack Criteria			
Stack Number	**Emission Unit or Pollution Control Equipment ID**	**Minimum Height (feet above ground surface)**	**Maximum Exit Diameter (feet)**
1	Boiler/Main Stack	196.5	6.0

B. Stack criteria described in Table 3 may be changed without prior approval from the Division provided that:

1. An air quality impact analysis is performed either by the facility or the Division (if requested by the facility in writing) in accordance with Env-A 606, *Air Pollution Dispersion Modeling Impact Analysis Requirements*, and the "Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire," and
2. The analysis demonstrates that emissions from the modified stack will continue to comply with all applicable emission limitations and ambient air limits.

C. All air modeling data and analyses shall be kept on file at the facility for review by the Division upon request.

V. Operating and Emission Limitations

The Owner or Operator shall be subject to the operating and emission limitations identified in Table 4:

Table 4 - Operating and Emission Limitations

Item #	Requirement	Applicable Emission Unit	Regulatory Basis
1	<u>*24-hour and Annual Ambient Air Limit – Boiler*</u> 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 Application Review Summary prepared by DES. The compliance demonstration must be updated using one of the methods provided in Env-A 1405 if: a. There is a revision to the list of RTAPs; 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 water treatment chemical will increase); or c. A new RTAP will be emitted that was not evaluated in the Application Review Summary (e.g., a new water treatment chemical will be used).	EU1	Env-A 1400
2	<u>*Revisions of the List of RTAPs*</u> 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	RSA 125-I:5 IV
3	<u>*Methods of Demonstrating Compliance*</u> In accordance with Env-A 1405.01, the owner of any device or process, that emits a regulated toxic air pollutant, shall determine compliance with the ambient air limits (AALs) by using one of the methods provided in Env-A 1405.02, Env-A 1405.03, Env-A 1405.04, Env-A 1405.05 or Env-A 1405.06.	Facility Wide	Env-A 1405.01
4	<u>*Compliance Demonstration*</u> In accordance with Env-A 1402.01(c)(3), documentation for the demonstration of compliance shall be retained at the facility, and shall be made available to the DES for inspection.	Facility Wide	Env-A 1402.01(c)(3)

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Basis**
5	*Contaminant Limits for On-Spec Used Oil* a. The used oil shall not otherwise exhibit any hazardous waste characteristic as specified in Env-Wm 403; b. The used oil shall not be mixed with hazardous waste; and c. The allowable limits of the contaminants in on-spec used oil shall be as follows: Sulfur (% by weight) 0.40% maximum Arsenic 5 ppm maximum Cadmium 2 ppm maximum Chromium 10 ppm maximum Lead 100 ppm maximum Halogens (as HCl) 1,000 ppm maximum PCB's Less than 2 ppm	EU1	Env-Wm 807.02
6	*RTAP Operating Limitations – Fuel Limits* To show compliance with Env-A 1400, the facility shall limit the usage of on-spec used oil to 4,286 gallons during any consecutive 24-hour period.	EU1	Env-A 1400
7	*Sulfur Content of No. 2 Fuel Oil and On-Spec Used Oil* The sulfur content of No. 2 fuel oil and on-spec used oil shall not exceed 0.4% sulfur by weight.	Facility Wide	Env-A 1604.01(a)
8	*Precautions to Prevent, Abate, and Control Fugitive Dust* Any person engaged in any activity, except those listed in Env-A 1002.02(b), that emits fugitive dust within the state shall take precautions throughout the duration of the activity in order to prevent, abate, and control the emission of fugitive dust including but not limited to wetting, covering, shielding, or vacuuming.	Facility Wide	Env-A 1002.04
9	*Maximum Gross Heat Input Rate* The Boiler is limited to a maximum gross heat input capacity of 250 MMBtu/hr, which is equivalent to 165,000 lb steam/hr averaged over a 24-hour period at 850 degrees F and 695 psig, assuming a Boiler efficiency of 68% and a wood chip moisture content of 50%.	EU1	Temporary Permit Application FY07-0091

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Basis**
10	*Allowable Fuels – Boiler* Based on facility operations, fuel fed to the Boiler shall consist of any of the following: a. Whole tree wood chips and mill residue at approximately 8.8 MMBtu/ton (at 50% moisture); b. Clean processed wood fuel ranging from approximately 8.8 to 14 MMBtu/ton at 20-50% moisture; c. No. 2 fuel oil; and d. On-spec used oil that meets the contaminants levels identified in Table 4 Item 5 at a maximum of 0.4% sulfur by weight.	EU1	Temporary Permit Application FY07-0091
11	*Annual Capacity Limitation for Liquid Fuels* The owner or operator is opting out of Subpart Db NOx emissions limitations: a. By limiting the annual No. 2 fuel oil and on-spec used oil capacity factor to less than 10%, which is equivalent to 1,564,400 gal/yr[3]; and b. The nitrogen content of No. 2 fuel oil and on-spec used oil combusted in the Boiler shall be less than 0.3% by weight.	EU1	40 CFR 60 Subpart Db Section 60.44b(j) and (k)
12	*NSPS Particulate Matter Emission Limit* Total "particulate matter" emissions from the Boiler shall be less than or equal to 0.10 lb/MMBtu.[4]	EU1	40 CFR 60 Subpart Db Section 60.43b(c)(1)
13	*NSPS Opacity Limit* The average opacity shall not be greater than 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity.	EU1	40 CFR 60 Subpart Db Section 60.43b(f)
14	*NSPS Particulate Matter and Opacity Standards* The total suspended particulate matter and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.	EU1	40 CFR 60 Subpart Db Section 60.43b(g)
15	*NOx RACT for Utility Boilers* For Boilers firing wood fuel or capable of firing wood fuel and oil, equipped with a traveling, shaker, or vibrating grate, the NOx emissions from such devices shall be less than or equal to 0.33 lb/MMBtu, based on a 24-hour calendar day average.[5]	EU1	Env-A 1211.03(c)(5)a.

[3] The annual capacity factor of 1,564,400 gal/yr is based on a 12-month rolling average.

[4] This limit is more stringent than the 0.15 lb/MMBtu emission limit specified in Env-A 2002.08(c)(2). Here, "particulate matter" is considered the filterable, total suspended particulate matter collected from use of USEPA Method 5. This does not include the condensible portion.

[5] This NOx RACT limit of 0.33 lb NOx/MMBtu is applicable at all times of operation, whether or not the facility is operating to produce renewable energy certificates. This is less stringent than the 0.075 lb NOx/MMBtu emission limit based on a quarterly average that Bridgewater has voluntarily chosen to comply with for the purpose of qualifying for generating renewable energy certificates in the state of Connecticut.

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Basis**
16	*NOx Emission Limit Required for Generating Renewable Energy Certificates for the State of Connecticut* NOx emissions from the Boiler shall be limited to less than or equal to 0.075 lb NOx/MMBtu, based on a calendar quarterly average in order to qualify for generation of renewable energy certificates for the State of Connecticut.	EU1	Temporary Permit Application FY07-0091
17	*Prevention of Significant Deterioration (PSD) Avoidance* To avoid the federal PSD program, facility wide emissions of NOx and CO shall be limited to less than 250 tpy for each pollutant.	Facility Wide	40 CFR 52.21(b)(1)(i)(b)
18	*Prevention of Significant Deterioration (PSD) Avoidance* To avoid the federal PSD program, emissions from EU1 (the Wood/Oil-fired Boiler) shall not exceed the following: a. 57.0 lb NOx/hr averaged over any consecutive 365-day period; and b. 57.0 lb CO/hr averaged over any consecutive 365-day period. Compliance with these emissions limits shall be demonstrated using the NOx and CO CEM data.	EU1	40 CFR 52.21(b)(1)(i)(b)
19	*Primary Ambient Air Quality Standards for Carbon Monoxide and Primary and Secondary Air Quality Standards for Nitrogen Dioxide* The owner or operator shall control CO emissions from EU1 by varying the total quantity of input combustion air and/or local distribution of that air into EU1. EU1 shall be equipped with a fuel distribution system, overfire air control system, and undergrate air control system for optimum control of CO emissions. EU1 shall be equipped with a RSCR system for optimum control of NOx emissions from EU1.	EU1	Env-A 305 & 306
20	*Compliance With Standards and Maintenance Requirements* At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate the boiler including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to DES and EPA, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.	EU1	40 CFR 60 Subpart A Section 60.11(d)

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Basis**
21	*Particulate Matter Pollution Control Equipment* The multiclone, gravel bed filter, and reverse jet-pulse baghouse for the gravel bed filter (PCE1, PCE2, and PCE3) shall be fully operational upon facility startup and shall not be bypassed during startup, operation, or shutdown of the steam generating unit.	PCE1, PCE2, & PCE3	Temporary Permit Application FY07-0091
22	*Operational Requirement of the RSCR System* When in operation, the RSCR system shall be operated so as to attempt to maintain a NOx emission rate from the Boiler to not exceed 0.075 lb NOx/MMBtu on a quarterly basis The ammonia feed rate shall be adjusted based on the NOx emissions rate as determined by the NOx CEMS.[6] PCE4 and PCE5 shall not be operated simultaneously.	EU1 &PCE4	Temporary Permit Application FY07-0091
23	*Operational Requirement of the RSCR System* The RSCR System shall be equipped with two diesel fuel oil burners with a combined maximum flow of 17 gal/hr diesel fuel at 137,000 Btu/gal or 2.33 MMBtu/hr combined maximum gross heat input rate. The burners shall be operated in conjunction with a Honeywell Burner Management System to maintain a temperature within the catalyst bed of 350 to 650 ^{o}F.	EU1 & PCE4	Temporary Permit Application FY07-0091
24	*Operational Requirement of the SNCR System* When in operation, the SNCR system shall be operated to achieve the lowest NOx emission rate possible without violating the ammonia slip emission limit in Table 4, Item 25. PCE4 and PCE5 shall not be operated simultaneously.	EU1 & PCE5	Temporary Permit Application FY07-0091
25	*Ammonia Slip Emissions Limit* Ammonia slip emissions from the Boiler shall be limited to 20 ppmvd @ 6% O2 dry volume.	EU1, PCE4, & PCE5	Temporary Permit Application FY07-0091
26	*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.	EU1	Env-A 2002.02

[6] This condition is applicable when Bridgewater Power Company is voluntarily complying with the 0.075 lb NOx/MMBtu emission limit required for generating renewable energy certificates for the State of Connecticut. In addition, note that at all times the RSCR must be operated so that the Boiler NOx emissions are below 0.33 lb/MMBtu to demonstrate compliance with the New Hampshire (NH) NOx RACT limit of 0.33 lb/MMBtu in Table 4 Item 15.

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Basis**
27	*Activities Exempt from Visible Emission Standards* For those steam generating units subject to 40 CFR 60, no more than one of the following two exemptions shall be taken: a. During periods of startup, shutdown and malfunction, average opacity shall be allowed to be in excess of 20% for one period of 6 continuous minutes in any 60-minute period; or b. During periods of normal operation, 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.	EU1	Env-A 2002.04(a)
28	*Activities Exempt from Visible Emission Standards* Exceedances of the opacity standard in Env-A 2002 shall not be considered violations if the Owner or Operator demonstrates to the Division that such exceedances: a. Were the result of the adherence to good boiler operating practices which, in the long term, result in the most efficient or safe operation of the boiler; b. Occurred during periods of cold startup of a boiler over a continuous period of time resulting in efficient heat-up and stabilization of its operation and the expeditious achievement of normal operation of the unit; c. Occurred during periods of continuous soot blowing of the entire boiler tube section over regular time intervals as determined by the operator and in conformance with good boiler operating practice; or d. Are the result of the occurrence of an unplanned incident in which the opacity exceedance was beyond the control of the operator and in response to such incident, the operator took appropriate steps in conformance with good boiler operating practice to eliminate the excess opacity as quickly as possible.	EU1	Env-A 2002.04(d), (e), and (f)

VI. Monitoring and Testing Requirements

The Owner or Operator is subject to the monitoring and testing requirements as contained in Table 5:

Table 5 - Monitoring and Testing Requirements

Item #	Parameter	Method of Compliance	Frequency	Applicable Unit	Regulatory Basis
1	Sulfur Content of Liquid Fuels	Conduct testing in accordance with appropriate ASTM test methods or retain delivery tickets in accordance with Table 6, Item #3 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
2	Ammonia Flow to SNCR & RSCR	When in operation, the ammonia flow to the SNCR and RSCR shall be continuously monitored using a DES approved ammonia flow meter. Ammonia usage shall be calculated and recorded daily.	Continuous & daily calculations	EU1, PCE4, & PCE5	RSA 125-C:6, XI, Env-A 801.02(a)
3	RSCR Catalyst Bed Temperature	When in operation, the temperature in the RSCR catalyst bed(s) shall be continuously monitored using DES approved temperature monitors. The owner or operator shall calculate and record the average daily temperature within the RSCR catalyst bed.	Continuous & average daily calculations	EU1 & PCE4	RSA 125-C:6, XI, Env-A 801.02(a)
4	Ammonia Flow/NOx Emission Rate Comparison	Daily the owner or operator shall calculate and record the average daily ammonia flow rate in gal/hr based on the ammonia flow meter and calculate the ratio of the average daily ammonia flow rate in gal/hr/average daily NOx emission rate in lb/hr (based on the NOx CEM data) for the purpose of determining catalyst performance.	Daily	EU1, PCE4, & PCE5	RSA 125-C:6, XI, Env-A 801.02(a)
5	Ammonia Slip	The owner or operator shall conduct initial and annual ammonia stack testing after the installation of the RSCR and SNCR Systems in accordance with Section IX of this Permit.	Initial performance test and annually thereafter	EU1	RSA 125-C:6, XI, Env-A 801.02(a)

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
6	Opacity CEM (COMS)	The owner or operator of an affected facility subject to the opacity standard under 60.43b, shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The span value shall be between 60 and 80 percent. The COMS shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 1 and Env-A 808. Determination of compliance with opacity emission limits established in this permit shall be made by the facility COMS or visible emission readings taken once per day following the procedures specified in 40 CFR 60, Appendix A, Method 9.	Continuous	EU1	40 CFR 60 Subpart Db Section 60.48 b(a),(e)(1), 40 CFR 60 Appendix B Performance Specification 1, & Env-A 808.03(b), (c)
7	NOx CEM	The owner or operator of an affected facility wishing to opt out from the PSD requirements, shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the NOx emissions discharged to the atmosphere and record the output of the system. The NOx CEM shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 2 and Env-A 808. Determination of compliance with NOx emission limits established in Table 4, Items 15 through 18 of this permit shall be made using data from the facility NOx CEM. The NOx emission rate shall be calculated daily in lb/hr averaged over a rolling 365-day period and in lb/MMBtu averaged over 24-hrs. Calculations shall be performed as specified in Table 5, Items 12 and 13.	Continuous	EU1	40 CFR 60 Appendix B Performance Specification 2 & Env-A 808.03(c)

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
8	CO CEM	The owner or operator of an affected facility wishing to opt out from the PSD requirements shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the CO emissions discharged to the atmosphere and record the output of the system. The CO CEM shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 4 and Env-A 808. Determination of compliance with CO emission limits established in Table 4, Items 17 and 18 of this permit shall be made using data from the facility CO CEM. The CO emission rate shall be calculated daily in lb/hr averaged over a rolling 365-day period and in lb/MMBtu averaged over 24 hours. Calculations shall be performed as specified in Table 5, Items 12 and 13.	Continuous	EU1	40 CFR 60 Appendix B Performance Specification 4 & Env-A 808.03(c)
9	O_2 CEM	The O_2 CEM shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 3 and Env-A 808.	Continuous	EU1	40 CFR 60 Appendix B Performance Specification 3 & Env-A 808.03(c)
10	Volumetric Flow CERM	Continuous emission rate monitoring systems (CERMS) shall meet all of the requirements of 40 CFR 60, Appendix B, Performance Specification 6. The stack flow monitor shall have an automatic blow-back purge system activated during boiler operation. The stack volumetric flow measuring device combined with the NOx and CO concentrations obtained from the CEM shall be used to calculate mass emission rates for comparison with the emissions limitations specified in Table 4, Items 15 through 18.	As specified	EU1	40 CFR 60 Appendix B Performance Specification 6 & Env-A 808.03(d)

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
11	QA/QC Plan Requirements	The Permittee is required to operate and maintain opacity and gaseous CEM systems and shall: a) Maintain a quality assurance/quality control (QA/QC) plan, which shall contain written procedures for implementation of its QA/QC program for each CEM system; b) Review the QA/QC plan and all data generated by its implementation at least once each year; c) Revise or update the QA/QC plan, as necessary, based on the results of the annual review, by documenting any changes made to the CEM or changes to any information provided in the monitoring plan; d) Make the revised QA/QC plan available for on-site review by the division at any time; e) Within 30 days of completion of the annual QA/QC plan review, certify in writing that the Permittee will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reasons for change.	Annually	EU1	Env-A 808.06
12	Calculations of CEM Calendar Day Averages	Calendar day average shall be calculated as follows: a) Calendar day average=(Sum of all valid hour lb/hr averages for the calendar day)/(24 hours – hours of CEM system downtime for the day); b) Calendar day averages shall only be valid for days with 18 or more valid hours of CEM data; c) A valid hour of CEM data shall be defined as a minimum of 42 minutes collection of CEM readings taken in a calendar hour; and d) Hours of CEM system downtime shall be defined as the number of calendar hours when the CEM system has not collected data or is out-of-control for greater than 18 minutes for any reason (i.e. audits, CEM system calibration, CEM system failures, etc.)	As needed	EU1	40 CFR 60 Appendix B & Env-A 808.14

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
13	Calculations of CEM Consecutive 365-day Averages	Consecutive 365-day average shall be calculated as follows: a) Consecutive 365-day Average=(Sum of all valid calendar day averages for the 365-day period)/(365 days – days of CEM system downtime); b) Days of CEM system downtime shall be defined as the number of calendar days when the CEM system has collected less then 18 valid hours of CEM data; c) Hours or days when the CEM system has been intentionally shutdown when the facility is not operating shall not be counted as CEM system downtime.	As needed	EU1	40 CFR 60 Appendix B & Env-A 808.14
14	General Audit Requirements	Required quarterly audits shall be done anytime during each calendar quarter, but successive quarterly audits shall occur no more than 4 months apart; and The Permittee shall notify the division at least 30 days prior to the performance of a RATA.	Quarterly	EU1	Env-A 808.07
15	Gaseous CEM Audit Requirements	Audits for the gaseous CEM systems shall be performed in accordance with procedures described in 40 CFR 60, Appendix F and Env-A 808.08	Quarterly	EU1	Env-A 808.08
16	Opacity CEM Audit Requirements	Audits for the opacity CEM systems shall be performed in accordance with procedures described in 40 CFR 60, Appendix B, Specification 1 and Env-A 808.09	Quarterly	EU1	Env-A 808.09
17	Data Availability Requirements	The Permittee shall operate the CEM systems at all times during operation of the source in accordance with Env-A 808.10, except for periods of CEM breakdown, repairs, calibration checks, preventive maintenance, and zero/span adjustments. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 90% on a calendar quarter basis. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 75% for any calendar month.	As specified	EU1	Env-A 808.10

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Basis**
18	CEM Excess Emissions	Excess emissions indicated by the CEM system shall be considered violations of the applicable emission limit for purposes of this permit, except where the owner or operator can adequately demonstrate to the DES that the recorded exceedance resulted from a CEM malfunction.	Continuously	EU1	Env-A 808.01(d)(f)
19	Continuous Steam Flow Monitor	The owner or operator shall install, maintain and operate a continuous steam flow rate monitoring/recording system which shall meet all applicable ASME specifications. Calibration of the steam flow transducer shall occur at least once annually. If adequate straight length of piping is not available, then in lieu of a measuring system that meets ASME specifications, the owner or operator may use a steam flow rate monitoring system that can be calibrated by instruments installed, maintained and calibrated per ASME specifications or by other methods approved by the DES.	Annually	EU1	Env-A 808.02(b)
20	Specification Used Oil Analysis	The owner or operator shall conduct testing of any on-spec used oil in accordance with appropriate ASTM test methods to determine compliance with contaminant limits specified in Table 4, Item 5.	Before using On-spec used oil	EU1	Env-Wm 807.10(b)(5)
21	On-spec Used Oil and No. 2 Fuel Oil Flow Monitoring	The owner or operator shall monitor the flow/use of No. 2 fuel oil with a fuel flow meter to determine compliance with permit limits specified in Table 4, Item 11. The owner or operator shall monitor the flow/use of on-site generated on-spec used oil flow with a fuel flow meter to determine compliance with permit limits specified in Table 4, Items 6 and 11. Fuel flow meters shall be maintained and calibrated in accordance with manufacturer's specifications.	Daily	EU1	40 CFR 60 Subpart Db Section 60.49b(d) & Env-A 604.01

VII. Recordkeeping Requirements

The Owner or Operator shall be subject to the recordkeeping requirements identified in Table 6:

Table 6 - Recordkeeping Requirements

Item #	Requirement	Duration/ Frequency	Applicable Unit	Regulatory Basis
1	*Record Retention and Availability* Keep the required records on file. These records shall be available for review by the Division upon request.	Retain for a minimum of 5 years	Facility Wide	Env-A 902
2	*General Recordkeeping Requirements for Combustion Devices* Maintain the following records of fuel characteristics and utilization for the fuel used in the combustion devices: a. Type (e.g. No. 2 fuel oil, on-spec used oil, whole tree chips, clean processed wood fuel, and mill residue) and amount of fuel burned in each device; and b. Sulfur content of any liquid fuel burned in terms of percent sulfur by weight.	Monthly	EU1	Env-A 903.03
3	*Liquid Fuel Oil Recordkeeping Requirements* In lieu of sulfur testing pursuant to Table 6, Item 2, the Owner or Operator may maintain fuel delivery tickets that contain the following information: a. The date of delivery; b. The quantity of delivery; c. The name, address and telephone number of the company making the delivery; and d. The maximum weight percentage of sulfur.	For each delivery of fuel oil/diesel to the facility	Facility Wide	Env-A 806.05
4	*General NO_x Recordkeeping Requirements* The owner or operator shall record 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 a. above, including: 1. Hours and days of operation per calendar month; 2. Number of weeks of operation; 3. Type and amount of each fuel burned; 4. Heat input rate in MMBtu/hr; 5. Actual NOx emissions for the calendar year and a typical high ozone day during that calendar year; and 6. Emission factors and the origin of the emission factors used to calculate the NOx emissions.	Maintain on a continuous basis	Facility Wide	Env-A 905.02
5	*Regulated Toxic Air Pollutants* Maintain records documenting compliance with Env-A 1400.	Maintain Current Data	Facility Wide	Env-A 902.01(c)

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
6	*RSCR & SNCR Recordkeeping Requirements* For the RSCR and SNCR systems, the owner or operator shall keep records of the following information in accordance with the required timeframes: a. Daily ammonia usage in gallons; b. Average daily ammonia flow in lb/hr; c. Daily calculated ratio of the Average daily ammonia flow (lb/hr) to average daily NOx flow (lb/hr); and d. Average daily temperatures of the RSCR catalyst beds.	Daily	PCE4 & PCE5	Env-A 906
7	*Recordkeeping Requirements for Add-On NOx Control Equipment* The owner or operator shall record and maintain 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. Current primary and secondary equipment control information codes; 3. Date tested; and 4. Method of determining destruction or removal efficiency, if not tested.	Maintain at the facility at all times	PCE4 & PCE5	Env-A 905.03
8	*CEMS and Steam Records* For each CEM system at the facility, the owner or operator shall keep the records of emission data recorded by the CEM system, including: a. Quarterly CEM/COM audit results; b. Rolling 365-day averages of NOx and CO in lb/hr and part per million (ppm) dry, whether or not an excess emissions has occurred; c. Daily averages of CO in lb/hr; d. Daily averages of NOx in lb/MMBTU; e. Calendar daily averages of percent of O2 on a dry basis. f. Calendar daily averages of percent of opacity; g. Calendar daily averages of steam generation rate; h. Calendar daily averages of stack flow (dscfm); and i. CEM system data availability.	Maintain on a continuous basis	EU1	Env-A 808 & Env-A 903.04

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Basis**
9	*NSPS Fuel Consumption Recordkeeping* Record and maintain records of the amounts of each fuel combusted during each day of operation and calculate the annual capacity factor individually for each fuel for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.	Daily & 12 month rolling average	EU1	40 CFR 60 Subpart Db Section 60.49b(d)
10	*NSPS Opacity Recordkeeping Requirement* The owner or operator shall maintain records of opacity.	Continuous	EU1	40 CFR 60 Subpart Db Section 60.49b(f)
11	*NSPS Startup, Shutdown, & Malfunction Recordkeeping Requirements* The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the Boiler; any malfunction in the operation of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.	Continuous	EU1	40 CFR 60 Subpart A Section 60.7(b)
12	*NSPS General Recordkeeping Requirements* The owner or operator shall maintain a file of all measurements, including continuous monitoring system, monitoring device (steam flow, stack volumetric flow), and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 years[7] following the date of such measurements, maintenance, reports, or records.	Continuous	EU1	40 CFR 60 Subpart A Section 60.7(f)
13	*NSPS Recordkeeping Requirement* The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day: a. Calendar date; b. The number of hours of operation; and c. A record of the hourly steam load.	Daily	EU1	40 CFR 60 Subpart Db Section 60.49b(p)

[7] New Hampshire has a more stringent record retention requirement of 5 years in Env-A 902.01 instead of the 2 year requirement in 40 CFR 60.

VIII. Reporting Requirements

The Owner or Operator shall be subject to the reporting requirements identified in Table 7 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 7 - Reporting Requirements

Item #	Requirement	Frequency	Applicable Emission Unit	Regulatory Basis
1	*Annual Emissions Report* Submit an annual emissions report which shall include the following information: a. Actual or estimated calendar year emissions from each device of NO_x, CO, SO_2, TSP, and VOCs, HAPs, 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 information recorded in accordance with Table 6 Item 2.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.01
2	*NO_x Emission Statements Reporting Requirements* Submit the following information with the annual emission report: a. A breakdown of NO_x emissions reported pursuant to Table 7 Item 1 (by device) by month; and b. All data recorded in accordance with Table 6 Item 4.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 909
3	*CEM Audit Report* The CEM audit report for the calendar quarter, conducted as specified in Env-A 808 and Table 5 Items 15 and 16 shall be submitted within 30 days following the close of each calendar quarter.	Quarterly (no later than 30 days following the end of each quarterly reporting period)	EU1	Env-A 808.07 (Formerly Env-A 805)
4	*Excess Emission Reports*[8] The owner or operator of a source that is required to install and operate a CEM system, shall provide the following in each quarterly emission report: a. The information specified in 40 CFR 60.7(c) and any applicable subpart of 40 CFR 60; b. The daily averages of gaseous CEM measurements and calculated emission rates; c. Excess emission data recorded by the CEM system, including: 1. The date and time of the beginning and ending	Quarterly (no later than 30 days following the end of each quarterly reporting period)	EU1	Env-A 808.12 Env-A 808.13 40 CFR 60 Subpart Db Section 60.49b(h)

[8] Note that for NOx, excess emissions are based on the NOx RACT limit of 0.33 lb/MMBtu, and not the voluntary 0.075 lb/MMBtu emission limit the facility is complying with to qualify for generating renewable energy certificates.

Table 7 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Emission Unit**	**Regulatory Basis**
	of each period of excess emission; 2. The magnitude of each excess emission; 3. The specific cause of the excess emission; and 4. The corrective action taken. d. If no excess emissions have occurred, a statement to that effect; e. For gaseous measuring CEM systems, the daily averages of the measurements made and emission rates calculated; f. A statement as to whether the CEM system was inoperative, repaired, or adjusted during the reporting period; g. 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 inoperative; 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. h. For all "out of control periods" 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. i. The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating. j. The span value, of each analyzer in the CEM system and units of measurement for each instrument; and k. When calibration gas is used, the following information: 1. The 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 iv) The expiration date for all calibration gas bottles used.			

Table 7 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Emission Unit**	**Regulatory Basis**
5	*RSCR & SNCR Systems Quarterly Report* For the RSCR and SNCR systems, the owner or operator shall report the following information quarterly with the CEM Excess Emissions Report: a. Daily ammonia usage in gallons; b. Average daily ammonia flow in lb/hr; c. Daily calculated ratio of Average daily ammonia flow (lb/hr) to average daily NOx flow (lb/hr); and d. Average daily temperature of the RSCR catalyst beds.	Quarterly	PCE4 & PCE5	Env-A 910
6	*NSPS Annual Capacity Factor Reporting* Submit the annual capacity factor over the previous 12 months for each fuel fired in the Boiler in each semi-annual report to DES and EPA.	Semi-annually, postmarked by the 30th day following the end of the 6 month reporting period	EU1	40 CFR 60 Subpart Db Section 60.49b(q)(1)
7	*NSPS Very Low Sulfur Oil Recordkeeping and Reporting Requirement* The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period.	Semi-annually, postmarked by the 30th day following the end of the 6 month reporting period	EU1	40 CFR 60 Subpart Db Section 60.49b(r)
8	*Emission Based Fees* Pay emission-based fees in accordance with Condition XII.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 700

IX. Ammonia Slip Performance Testing/Compliance Testing Requirements

Within 60 days of achieving the maximum production rate of EU1 after the installation of the RSCR system (PCE4) and SNCR system (PCE5), and annually thereafter, the owner or operator shall conduct separate U.S. EPA Method stack tests at maximum operating rate conditions for the SNCR and RSCR systems, and/or at the request of the Division, at any other operating rate at which maximum emissions might occur. Testing shall be performed on the exhaust stack from EU1 and PCE4 and PCE5 as follows:

A. Ammonia concentration shall be measured following EPA CTM 0027 or DES approved alternative;

B. The testing shall follow all requirements specified in Env-A 802, Compliance Stack Testing for Stationary Sources, which includes but is not limited to the following:
   1. Submission of a Pre-test Protocol as specified in Env-A 802.04
   2. Holding a pretest meeting between DES, the owner or operator, and the contractor stack testing company at the facility as specified in Env-A 802.05.
   3. Submission of a stack testing report no later than 60 days following the successful completion of the stack test as specified in Env-A 802.11.

C. The owner or operator may use the facility's CEM data to correct the ammonia emissions to the units of the standard (20 ppmvd @ 6% O2 dry volume).

X. Permit Deviation Reporting Requirements

In accordance with 40 CFR 70.6(a)(3)(iii)(B), the Permittee shall report to the DES all instances of deviations from Permit requirements, by telephone (603-271-1370), fax (603-271-7053) or e-mail (pdeviations@des.state.nh.us), within 24 hours of such deviation. This report shall include the deviation itself, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventative measures taken. Said Permit deviation shall also be submitted in writing to the DES within ten (10) days of documentation of the deviation by facility personnel. Deviations are instances where any Permit condition is violated and has not already been reported as a malfunction or an emergency pursuant to Section XXVIII of the facility's Title V Operating Permit (TV-OP-008). Reporting a Permit deviation is not an affirmative defense for action brought for noncompliance.

XI. Permit Amendments

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

1. An administrative permit amendment includes the following:
   a. Corrects typographical errors;
   b. Requires more frequent monitoring or reporting; or
   c. 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 devices listed in Condition II and will not result in the emission of any air pollutant not emitted by the source or device.
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 filling 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 devices covered by this permit which increases the amount of a specific air pollutant currently emitted by such device or which results in the emission of any regulated air pollutant currently not emitted by such device.
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.

XII. 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 devices listed in Condition II.

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 devices listed in Condition II for each calendar year in accordance with the methods specified in Env-A 616, Determination of Actual Emissions. If the emissions are determined to be less than one ton, the emission-based fee shall be calculated using an emission-based multiplier of one ton.

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 XII.B.; and
DPT = The dollar per ton fee the Division has specified in Env-A 705.03(e).

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 2007 shall be submitted on or before April 15, 2008.