STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
SAMPLE APPLICATION FORM

FOR RENEWABLE ENERGY SOURCE ELIGIBILITY
Pursuant to New Hampshire Admin. Code Puc 2500 Rules

NOTE: When completing this application electronically, using the "tab" key after completing each answer will move the cursor to the next blank to be filled in. If a question is not applicable to your facility, then check the box next to N/A.

Pursuant to Puc 202, the signed application shall be filed with the Executive Director and Secretary of the New Hampshire Public Utilities Commission (Commission). To ensure that your submitted application is complete, please read RSA 362-F and N.H. Code Admin. Rules Puc 2500 before filling out this application. It is the burden of the applicant to provide timely, accurate and complete information as part of the application process. Any failure by the applicant to provide information in a timely manner may result in the Commission dismissing this application without prejudice.

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1. **ELIGIBILITY CLASS APPLIED FOR:** ☐ I ☐ II ☒ III ☐ IV

2. Applicant's legal name: Indeck Energy-Alexandria, LLC

3. Address: (1) 600 North Buffalo Grove Road
   (2)
   (3)
   Buffalo Grove (City) IL (State) 60089 (Zip code)

4. Telephone number: (847) 520-3212

5. Facsimile number: (847) 520-9883

6. Email address: mferguson@indeckenergy.com

7. Facility name: Indeck Alexandria Energy Center

8. Facility location: (1) 151 Smith River Road

(2) ______________________________

Alexandria NH 3222

(City) (State) (Zip code)

9. Latitude: 43 degrees 36 min. 10.99 sec. N. Longitude: 71 degrees 47 min.35.42 sec. W.

10. The name and telephone number of the facility's operator, if different from the owner: Same ☐

Tim Chase (603) 744-6355

(Name) (Telephone number)

11. The ISO-New England asset identification number, if applicable: See Attachment A or N/A: ☐ ✓

12. The GIS facility code, if applicable: MSS14211 or N/A: ☐ ✓

13. A description of the facility, including fuel type, gross nameplate generation capacity, the initial commercial operation date, and the date it began operation, if different. ✓

14. If Class I certification is sought for a generation facility that uses biomass, the applicant shall submit:
   - (a) quarterly average NOx emission rates over the past rolling year,
   - (b) the most recent average particulate matter emission rates as required by the New Hampshire Department of Environmental Services (NHDES),
   - (c) a description of the pollution control equipment or proposed practices for compliance with such requirements,
   - (d) proof that a copy of the completed application has been filed with the NHDES, and
   - (e) conduct a stack test to verify compliance with the emission standard for particulate matter no later than 12 months prior to the end of the subject calendar quarter except as provided for in RSA 362-F:12, II.
   - (f) [x] N/A: Class I certification is NOT being sought for a generation facility that uses biomass.

15. If Class I certification is sought for the incremental new production of electricity by a generation facility that uses biomass, methane or hydroelectric technologies to produce energy, the applicant shall:
   - (a) demonstrate that it has made capital investments after January 1, 2006 with the successful purpose of improving the efficiency or increasing the output of renewable energy from the facility, and
   - (b) supply the historical generation baseline as defined in RSA 362-F:2, X.
   - (c) [x] N/A: Class I certification is NOT being sought for the incremental new production of electricty by a generation facility that uses biomass, methane or hydroelectric technologies.

16. If Class I certification is sought for repowered Class III or Class IV sources, the applicant shall:
   - (a) demonstrate that it has made new capital investments for the purpose of restoring unusable generation capacity or adding to the existing capacity, in light of the NHDES environmental permitting requirements or otherwise, and

(b) provide documentation that eighty percent of its tax basis in the resulting plant and equipment of the eligible generation capacity, including the NHDES permitting requirements for new plants, but exclusive of any tax basis in real property and intangible assets, is derived from the new capital investments.

(c) [x] N/A: Class I certification is NOT being sought for repowered Class III or Class IV sources.

17. If Class I certification is sought for formerly nonrenewable energy electric generation facilities, the applicant shall:

(a) demonstrate that it has made new capital investments for the purpose of repowering with eligible biomass technologies or methane gas and complies with the certification requirements of Puc 2505.04, if using biomass fuels, and

(b) provide documentation that eighty percent of its tax basis in the resulting generation unit, including NHDES permitting requirements for new plants, but exclusive of any tax basis in real property and intangible assets, is derived from the new capital investments.

(c) [x] N/A: Class I certification is NOT being sought for formerly nonrenewable energy electric generation facilities.

18. If Class IV certification is sought for an existing small hydroelectric facility, the applicant shall submit proof that:

(a) it has installed upstream and downstream diadromous fish passages that have been required and approved under the terms of its license or exemption from the Federal Energy Regulatory Commission, and

(b) when required, has documented applicable state water quality certification pursuant to section 401 of the Clean Water Act for hydroelectric projects.

(c) [x] N/A: Class IV certification is NOT being sought for existing small hydroelectric facilities.

19. If the source is located in a control area adjacent to the New England control area, the applicant shall submit proof that the energy is delivered within the New England control area and such delivery is verified using the documentation required in Puc 2504.01(a)(2) a. to e.

20. All other necessary regulatory approvals, including any reviews, approvals or permits required by the NHDES or the environmental protection agency in the facility's state.

21. Proof that the applicant either has an approved interconnection study on file with the commission, is a party to a currently effective interconnection agreement, or is otherwise not required to undertake an interconnection study.

22. A description of how the generation facility is connected to the regional power pool of the local electric distribution utility.

23. A statement as to whether the facility has been certified under another non-federal jurisdiction's renewable portfolio standard and proof thereof.

24. A statement as to whether the facility's output has been verified by ISO-New England.

25. A description of how the facility's output is reported to the GIS if not verified by ISO-New England.

26. An affidavit by the owner attesting to the accuracy of the contents of the application.

27. Such other information as the applicant wishes to provide to assist in classification of the generating facility.

28. This application and all future correspondence should be sent to:

Ms. Debra A. Howland
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
21 S. Fruit St, Suite 10
Concord, NH 03301-2429

29. Preparer's information:

Name: Michael D. Ferguson

Title: VP, Operations & Asset Management

Address: (1) 600 North Buffalo Grove Road

(2) Suite 300

(3) ____________________

Buffalo Grove (City) IL (State) 60089 (Zip code)

30. Preparer's signature: Mike Ferguson

Attachment A

I. The names and addresses of the Contacts for the Applicant, Indeck Energy - Alexandria, LLC ("Indeck") are as follows: -

Primary Contact:

Indeck Energy - Alexandria, LLC
c/o Michael D. Ferguson
Vice President
Indeck Energy Services, Inc.
600 North Buffalo Grove Road
Buffalo Grove, Illinois 60089
Tel: (847) 520-3212
Fax: (847) 520-9883
mferguson@indeckenergy.com

Secondary Contact:

Indeck Energy - Alexandria, LLC
c/o Tim Chase
Plant Manager
151 Smith River Road
Alexandria, NH 03222
Tel: (603) 744-6355
Fax: (603) 744-6755
Cell: (603) 393-3697
tchase@indeckenergy.com

II. The ISO New England Inc. asset identification number –

Indeck Alexandria's electrical output that is sold to Public Service Company of New Hampshire ("PSNH") is currently verified by PSNH and is reported under MSS ID #14211 to ISO New England, Inc.

III. Description of the Facility, including fuel type, gross nameplate capacity and the initial commercial operation date –

Indeck owns an operating 16.5 (gross), 15.2 (net) MW biomass-fired generator (the "Facility" or "Alexandria") located in Alexandria, New Hampshire on Smith River Road. The Facility generates electrical energy using biomass energy (whole tree chips, sawdust and clean processed wood fuels). The electrical energy is either used by Alexandria in its business operations, the production of electrical energy, or sold to Northeast Utilities' PSNH. The Facility is interconnected to PSNH's 34 KV distribution line located along Smith River Road. The Facility initially commenced commercial operation in January 1988, ceased operations in November 1994 and was re-commissioned, after a fourteen-year hiatus, on January 31, 2009. As such, per the certification requirements of PUC 2502.09, the Facility began operation on or before January 1, 2006, produces electricity from eligible biomass technologies and has a gross nameplate capacity less than 25 MW.

Additional history and technical details of the Facility may be found in the attached Facility's Application for certification as a New Hampshire Class III source.

IV. Copy of regulatory approvals required by local, state and federal authorities –

Additional history and technical details of the Facility may be found in the attached Facility's Application for certification as a New Hampshire Class III source.

V. Copy the Facility's Interconnection Agreement –

A copy the Facility's Interconnection Agreement may be found in the attached Facility's Application for certification as a New Hampshire Class III source.

VI. Description of the Facility's Interconnection with ISO New England –

Additional history and technical details of the Facility may be found in the attached Facility's Application for certification as a New Hampshire Class III source.

VII. Other state renewable portfolio standard certification –

Indeck has received an order from the Maine Public Utilities Commission ("MPUC") certifying the Facility as a Maine Class I renewable resource. The New Hampshire Public Utilities Commission ("NHPUC") has conditionally qualified the Facility as a New Hampshire Class III source. Indeck is also certified for Class I treatment in CT and has filed with the states of Rhode Island and the commonwealth of Massachusetts.

Additional history and technical details of the Facility may be found in the attached Facility's Application for certification as a New Hampshire Class III source.

VIII. Verification of the Facility's output by the ISO New England –

Indeck Alexandria's electrical output is verified by PSNH and is reported under MSS ID #14211 to ISO New England, Inc. ISO New England, Inc., in turn, reports this information to APX, Inc., the operator of the NEPOOL Generation Information System ("NEPOOL GIS").

Summary

Indeck is filing this application with the NHPUC for certification of Alexandria's electric production for treatment as New Hampshire Class III certificates starting on April 1, 2010. In the event that a retroactive approval for Class III treatment can not be made, Indeck requests the earliest possible certification date for New Hampshire Class III treatment.

Per the certification requirements of PUC 2502.09, the Facility began operation on or before January 1, 2006, produces electricity from eligible biomass technologies and has a gross nameplate capacity less than 25 MW.

Indeck believes that this request is in the best interest of New Hampshire customers as the demand for Class I Certificates in New Hampshire is significantly smaller than that of Class III Certificates. The Minimum Certificate Obligation percentage in 2010 for Class III is 6.5% and for Class I it is 1%.

AFFIDAVIT

I hereby certify, under pains and penalties of perjury, that I have personally examined and am familiar with the information submitted herein and, based upon my inquiry of those individuals responsible for obtaining the information, I believe that the information is true, accurate and complete. I am aware that there are significant penalties, both civil and criminal, for submitting false information, including both fines and punishment. My signature below certifies all information submitted on this application form.

Signature of Authorized Representative:

Michael D. Ferguson

Michael D. Ferguson, Vice President

4/28/10

Date

THE STATE of NEW HAMPSHIRE
Public Utilities Commission

Facility Application to qualify for Class III certificate acquisition under PUC 2500 of the New Hampshire Electric Renewable Portfolio Standard

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SECTION I: IDENTIFICATION INFORMATION

(1). Name and Address of Applicant:

Indeck Energy-Alexandria, LLC, 600 North Buffalo Grove Road, Suite 300, Buffalo Grove, IL 60089

(2). Name and Location of the applying Facility:

Indeck Alexandria Energy Center, 151 Smith River Road, Alexandria NH 03222

(3). ISO-New England Asset Identification number:

ISO-NE ID# 14211

(4). GIS Facility Code:

14211

(5) Name and Telephone number of the Facility's operator, If different from the owner:

TIM CHASE
~~[illegible]~~, Plant Manager, Indeck Alexandria Energy Center, (603) 744-6355, Email: ~~[illegible]@indeckenergy.com~~
tchase@indeckenergy.com

SECTION II: FACILITY AND FUEL DESCRIPTION

(1). Fuel Type:

Whole tree chips, sawdust & clean processed wood fuels.

Gross Nameplate Generation Capacity:

16.5 MW

Initial Commercial Operation date:

January 1988

Actual Facility Operation date, if different from Initial Commercial Operation date:

JANUARY 31, 2009

(2) If a Biomass source provide –

NOx and particulate matter emission rates:

The facility will meet the emissions requirements of the NH RPS which are 0.075 lb per MMBTU NOx and PM at or below 0.02 lbs per MMBTU.

Description of pollution control equipment:

Or proposed practices for compliance with such requirements:

Alexandria is installing an innovative pollution control system to reduce NOx emissions; the facility will use a Selective Non-Catalytic Reduction System (SNCR). The SNCR system shall operate to achieve the lowest NOx emission rate possible without violating the ammonia slip emission limits. This SNCR is different than other pollution control systems that have been installed because it will inject more ammonia, resulting in more NOx being removed than in other conventional pollution control systems. The backside of the SNCR will have an ammonia scrubber to clean and collect ammonia slip and reuse the ammonia in the SNCR system.

(3) Description of how the generation facility is connected to the distribution utility:

The facility is connected to the distribution utility at Disconnect Number 245 onto the 34.5 kV distribution line that is connected to the Pemigewasset substation.

(4) Is the Facility's output verified by ISO-New England? If not explain how the output is verified:

YES

(5) Description of how the facility's output is reported to the GIS **if not** verified by ISO-New England:

N/A

SECTION III: CERTIFICATIONS

(1). List all other non-federal jurisdiction's renewable portfolio standards the facility has been certified under, if any, **AND** attach proof thereof:

Maine

CT ATTACHED

NH ATTACHED CONDITIONAL APPROVAL :

SECTION IV: REGULATORY COMPLIANCE DOCUMENTATION

(1). List all applicable regulatory approvals, including any reviews or permits required by the New Hampshire department of environmental services:

1. Air Permit from the State of New Hampshire Department of Environmental Services Air Resources Division, issued on February 2, 2008.

2. Water Withdrawal Permit from the Department of the Army, New England Division, issued on 09/17/1987.

3. Groundwater Release Detection Permit re-issued by NHDES 6/21/05.

4. Stormwater Discharge Permit to be issued by NHDES covered under EPA/DES general approval.

(2). Confirm whether applicant has an approved interconnection study on file (provide copy) with the commission **or** is a party to a current effective interconnection agreement, **or** is otherwise not required to undertake an interconnection study (explain):

Applicant is party to an effective interconnection agreement; portions of that agreement are attached.

(3) **If** a biomass facility, has a copy of the completed application been filed with the New Hampshire department of environmental services (please attach documentation). (Check either "Yes" or "No")

☒ YES

☐ NO

SECTION V: ADDITIONAL INFORMATION

The Applicant may choose to provide in the space provided or through attached document(s), additional information to assist in classification of the generating facility. If document(s) are attached, provide a descriptive list below:

Alexandria was first commercially operational in January 1988. In November 1994 the facility was shut down as part of the Public Service of New Hampshire's bankruptcy settlement. Indeck Energy-Alexandria, LLC purchased the facility in 1997. In 2008, Indeck Energy-Alexandria, LLC began re-commissioning the facility. For the re-commissioning Alexandria has received all necessary permits and approvals.

During the re-commissioning many improvements are being made to the facility and the boiler to increase the efficiency and performance of the facility. Such improvements to the boiler are the addition of over-fire air nozzles to improve combustion and the addition of super-heater surface area to the boiler to increase steam temperature and increase turbine efficiency. The low pressure end of the turbine casing has been reshaped to improve steam flow to the condenser, again increasing turbine efficiency and performance.

In addition to improvements to the boiler and the pollution control system, other improvements have been made to the facility to improve performance and increase efficiency. For fuel handling, the facility is implementing fuel pile management techniques to lower fuel moisture and produce a more homogeneous fuel consistency. Lower moisture and consistent fuel allows the boiler to operate more consistently and efficiently. Variable speed controllers were installed to the fuel in-feed conveyor to improve surge bin level control, resulting in more efficient control of the fuel feed into the boiler. Other improvements include a redesign of the water balance of the facility to lower water consumption, generate less waste water and improve water quality for the facility. Lastly, the ash streams from the facility are separated as fly ash and bottom ash. The fly ash is a beneficial fertilizer and the bottom ash is recycled.

Attached please find two letters, one from New Hampshire Public Utilities Commission and the other from the Department of Environmental Services, to collaborate the shut down date of the Alexandria facility. In addition, please find the attached Historical Generation Sheet and the Air Permit to further demonstrate that Alexandria was shut down in November of 1994.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2008-336

November 18, 2008

INDECK ENERGY-ALEXANDRIA, LLC
Request for Certification for RPS Eligibility

ORDER GRANTING NEW RENEWABLE RESOURCE CERTIFICATION

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

The Indeck Energy-Alexandria (Indeck) biomass facility is certified as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules.

II. BACKGROUND

A. New Renewable Resource Portfolio Requirement

During its 2007 session, the Legislature enacted an Act To Stimulate Demand for Renewable Energy (Act). P.L. 2007, ch. 403 (codified at 35-A M.R.S.A. § 3210(3-A)). The Act added a mandate that specified percentages of electricity that supply Maine's consumers come from "new" renewable resources.[1] Generally, new renewable resources are renewable facilities that have an in-service date, resumed operation or were refurbished after September 1, 2005. The percentage requirement starts at one percent in 2008 and increases in annual one percent increments to ten percent in 2017, unless the Commission suspends the requirement pursuant to the provisions of the Act.

As required by the Act, the Commission modified its portfolio requirement rule (Chapter 311) to implement the "new" renewable resource requirement. *Order Adopting Rule and Statement of Factual and Policy Basis,* Docket No. 2007-391 (Oct. 22, 2007). The implementing rules designated the "new" renewable resource

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[1] Maine's electric restructuring law, which became effective in March 2000, contained a portfolio requirement that mandated that at least 30% of the electricity to supply retail customers in the State come from eligible resources, which are either renewable or efficient resources. 35-A M.R.S.A. § 3210(3). The Act did not modify this 30% requirement.

requirement as "Class I"[2] and incorporated the resource type, capacity limit and the vintage requirements as specified in the Act. The rules thus state that a new renewable resource used to satisfy the Class I portfolio requirement must be of the following types:

- fuel cells;
- tidal power;
- solar arrays and installations;
- wind power installations;
- geothermal installations;
- hydroelectric generators that meet all state and federal fish
- passage requirement; or
- biomass generators, including generators fueled by landfill gas.

In addition, except for wind power installations, the generating resource must not have a nameplate capacity that exceeds 100 MW. Finally, the resource must satisfy one of four vintage requirements. These are:

1) renewable capacity with an in-service date after September 1, 2005;

2) renewable capacity that has been added to an existing facility after September 1, 2005;

3) renewable capacity that has not operated for two years or was not recognized as a capacity resource by the ISO-NE or the NMISA and has resumed operation or has been recognized by the ISO-NE or NMISA after September 1, 2005; or

4) renewable capacity that has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

The implementing rules (Chapter 311, § 3(B)(4)) establish a certification process that requires generators to pre-certify facilities as a new renewable resource under the requirements of the rule and provides for a Commission determination of resource eligibility on a case-by-case basis.[3] The rule contains the information that must be included in a petition for certification and specifies that the Commission shall provide an opportunity for public comment if a petitioner seeks certification under

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[2] The "new" renewable resource requirement was designated as Class I because the requirement is similar to portfolio requirements in other New England states that are referred to as "Class I." Maine's pre-existing "eligible" resource portfolio requirement is designated as Class II.

[3] In the *Order Adopting Rule* at 6, the Commission noted that a request for certification can be made at any time so that a ruling can be obtained before a capital investment is made in a generation facility.

vintage categories 2, 3 and 4. Finally, the rule specifies that the Commission may revoke a certification if there is a material change in circumstance that renders the generation facility ineligible as a new renewable resource.

B. Petition for Certification

On August 13, 2008, Indeck filed a petition to certify its biomass facility as a Class I renewable resource. The Indeck facility is a 16.5 MW biomass-fired facility located in Alexandria, New Hampshire that will combust whole tree chips, sawdust and virgin processed wood fuels. The petition states that the facility began operation in 1988, but was shut down in 1994. The facility was re-commissioned in 2008 and expects to be operational during the fourth quarter of 2008. Consistent with the requirements of the rules, the Commission, on September 23, 2008, provided interested persons with an opportunity to comment on the petition. The Commission did not receive any comments on the petition.

III. DECISION

The Commission has delegated to the Director of Technical Analysis the authority to certify generation facilities as Class I new renewable resources pursuant to Chapter 311, § 3(B) of the Commission rules. *Delegation Order,* Docket No. 2008-184 (April 23, 2008). Based on the information provided by Indeck, I conclude that the Alexandria biomass facility satisfies the resource type, capacity limit and vintage requirements of the rule. The Indeck facility is a biomass-fired facility that has not operated for more than two years and will resume operations after September 1, 2005. Accordingly, the Indeck facility is hereby certified as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3 of the Commission rules. Indeck shall provide timely notice to the Commission of any material change in the operation of the facility from that described in the petition filed in this proceeding, including changes to the type of fueled used in the electricity generation process.

BY ORDER OF THE DIRECTOR OF TECHNICAL ANALYSIS

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Faith Huntington

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 09-03-09 APPLICATION OF INDECK ENERGY-ALEXANDRIA, LLC FOR QUALIFICATION OF INDECK ALEXANDRIA ENERGY CENTER AS A CLASS I RENEWABLE ENERGY SOURCE

January 27, 2010

By the following Commissioners:

John W. Betkoski, III
Kevin M. DelGobbo
Anthony J. Palermino

DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Department of Public Utility Control (Department) determines that the Indeck Alexandria Energy Center (Alexandria) biomass generating facility meets the average emissions rate criteria of equal to or less than .075 pounds of NOx per million BTU of heat input on a quarterly basis and, as a result, qualifies as a Class I renewable energy source as a biomass facility. The Department assigns it Connecticut Renewable Portfolio Standard (RPS) Registration Number CT00315-09 with an effective date of October 1, 2009.

B. Background of the Proceeding

In Decision dated September 13, 2006 in Docket No. 06-08-16, Application of Indeck Energy-Alexandria, LLC for Qualification of Indeck Alexandria Energy Center as a Class I Renewable Energy Source, the Department found that Alexandria would qualify as a Class I renewable energy source. However, with the statutory emissions requirements, the Department could not determine, at that time, that the proposed unit would have its application approved without production data and/or appropriate valid air permits demonstrating compliance with the emissions requirements.

By application dated March 23, 2009, Indeck-Energy-Alexandria, LLC (Indeck or Applicant) requested that the Department determine that the Alexandria biomass facility qualifies as a Class I renewable energy source.

Alexandria is a biomass facility located in Alexandria, New Hampshire. Alexandria began commercial operation on January 31, 2009 and has a nameplate capacity of 16.5 MW.

C. Conduct of the Proceeding

There is no statutory requirement for a hearing; no person requested a hearing, and none was held.

D. Participants in the Proceeding

The Department recognized Indeck Energy-Alexandria, LLC, 600 N. Buffalo Grove Rd., Buffalo Grove, IL 60089, and the Office of Consumer Counsel, Ten Franklin Square, New Britain, Connecticut 06051, as participants in this proceeding.

II. DEPARTMENT ANALYSIS

Pursuant to the General Statutes of Connecticut (Conn. Gen. Stat.) § 16-1(a)(26), "Class I renewable energy source" includes energy derived from a sustainable biomass facility. Conn. Gen. Stat. § 16-1(a)(45) defines "sustainable biomass" as biomass that is cultivated and harvested in a sustainable manner.

As provided in the application, Alexandria is a biomass facility located in Alexandria, NH 03222. Alexandria is currently owned by Indeck Energy-Alexandria, LLC. The facility will utilize clean sustainable biomass fuel including whole tree chips, sawdust and clean processed wood as a fuel source. The Applicant also indicated that in order to meet the Class I emission requirement, the facility installed a state of the art pollution control system. Application, p. 2. According to ISO New England's (ISO-NE) Seasonal Claimed Capability (SCC) Report dated 3/01/2009, Alexandria is a biomass electric generation facility.

Alexandria will obtain approximately 90% of its wood fuel from New Hampshire forests, the remaining wood will come from New England forests. New Hampshire, like most of New England, has been reforested within the last century, providing ample local sustainable supply. The New Hampshire wood will be harvested in accordance with New Hampshire Forestry Laws that foster responsible sustainable timber harvesting with minimal environmental impacts. The remaining wood fuel will be harvested in accordance with those States' forest management rules and practices. Good forest management practices include the collection of brush, fallen trees, limbs, tree tops, and other wood waste. The aforementioned wood sources result from regular forest lifecycle growth and from the waste derived from high grade timber harvesting and low grade wood harvesting. High grade timber harvesting has been occurring in New Hampshire for decades. This wood is sustainably harvested, not only in accordance with Forest Management regulations, but also to sustain the timber industries.

Alexandria is a counterparty to fuel supply arrangements with suppliers for natural wood fiber that adheres to the wood fuel standards stated above, as well as qualifying as Open-Loop Biomass as defined in the Internal Revenue Code Section 45. Lastly Alexandria has a thorough recording procedure for wood fuels delivered to the plant. This procedure assures that only clean wood is used at the facility and that a comprehensive record is maintained of the type of wood fuel delivered and burned at the facility.

According to the Connecticut Renewable Portfolio Attachment for Alexandria, the facility will be using 100% virgin wood fiber; wood fiber that comes directly from the forest. Most of the wood fuel will be waste wood in the form of whole tree chips. Brush and saw mill residue (sawdust, cutoffs, log mill slabs and board ends) are also a source of fuel for the facility. All the wood fuel used at the Alexandria facility is clean fuel not mixed with any construction and demolition wood waste. Alexandria is located in New Hampshire where it is illegal to combust construction and demolition derived wood fuel. The Department has previously approved these wood sources as eligible biomass fuels. The Department finds that a fuel supply consisting of whole tree chips, sawdust and clean processed wood qualify as a "biomass" that is cultivated and harvested in a sustainable manner.

On December 2, 2009, the Applicant submitted supplemental information regarding its emissions rate demonstrating a second quarter average of 0.037 and a third quarter average of 0.060. Additionally on January 11, 2010, the Applicant submitted supplemental information regarding its emissions rate demonstrating a fourth quarter average of 0.065. As a result, the Department finds that Alexandria meets the average emissions rate criteria of equal to or less than .075 pounds of NOx per million BTU of heat input on a quarterly basis.

Based on the foregoing and due to the fact that the facility's emission data is less than the statutory amount, the Department determines that Alexandria qualifies as a Class I status effective October 1, 2009 and, as such, will be eligible for 4th quarter RECs.

III. FINDINGS OF FACT

1. Alexandria's biomass facility is located in Alexandria, New Hampshire.

2. Alexandria is currently owned by Indeck Energy-Alexandria, LLC.

3. Alexandria began operation on January 31, 2009.

4. Alexandria has a nameplate capacity of 16.5 MW.

5. Alexandria is registered with ISO-NE as a biomass facility.

6. Alexandria's biomass facility will primarily burn whole tree chips, sawdust and clean processed wood.

7. Alexandria has an average emissions rate of 0.037 for its 2009 second quarter average and an average emissions rate of 0.060 for its third quarter..

8. Alexandria has an average emissions rate of 0.065 for the fourth quarter in 2009.

IV. CONCLUSION

Based on the evidence submitted, the Department finds that Alexandria qualifies as a Class I renewable generation source pursuant to C.G.S §16-1(a)(26).

The Department assigns each renewable generation source a unique Connecticut RPS registration number. Alexandria's Connecticut RPS registration number is CT00315-09 effective October 1, 2009.

The Department's determination in this docket is based on the information submitted by the Applicant. The Department may reverse its ruling or revoke the Applicant's registration if any material information provided by the Applicant proves to be false or misleading. The Department reminds Indeck that it is obligated to notify the Department within 10 days of any changes to any of the information it has provided to the Department.

V. ORDERS

1. The Applicant is required to file quarterly affidavits and documentation of Alexandria's nitrogen oxides' emissions according to the filing schedule below:

   Quarter 1 Emissions - Must be received by Department no later than June 1st.

   Quarter 2 Emissions - Must be received by Department no later than September 1st.

   Quarter 3 Emissions - Must be received by Department no later than December 1st.

   Quarter 4 Emissions - Must be received by Department no later than March 1st.

2. The Applicant shall file, by the date indicated in the table below, the Quarterly Generation Report from the GIS system that shows the number of RECs created by Alexandria on the Creation Date (as defined in Section 2.1(b) of the GIS

Operating rules, as amended from time to time) for said quarter. The reports are due on the following dates:

Quarter	Trading Period	Creation Date	Due Date
1	July 15 – Sept. 16	July 15	August 15
2	Oct. 15 – Dec. 16	Oct. 15	November 15
3	Jan. 15 – March 16	Jan. 15	February 15
4	April 15 – June 16	April 15	May 15

DOCKET NO. 09-03-09 APPLICATION OF INDECK ENERGY-ALEXANDRIA, LLC FOR QUALIFICATION OF INDECK ALEXANDRIA ENERGY CENTER AS A CLASS I RENEWABLE ENERGY SOURCE

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Kevin M. DelGobbo

Anthony J. Palermino

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

1/27/10

Kimberley J. Santopietro
Executive Secretary
Department of Public Utility Control

Date

DE09-008

The State of New Hampshire

DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

February 18, 2009

RECEIVED
FEB 19 2009
NH PUBLIC UTILITIES COMMISSION

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

Re: Conditional Certification as a Class III Renewable Energy Source
Indeck Energy-Alexandria, LLC
Alexandria, NH

Dear Ms. Howland:

The New Hampshire Department of Environmental Services (DES) received an application from Indeck Energy-Alexandria, LLC for their wood-fired power plant located in Alexandria, NH to be certified as a Class III renewable energy source. DES has reviewed the application and recommends that the Public Utilities Commission (PUC) grant conditional approval to Indeck Energy-Alexandria as a Class III renewable energy source eligible to generate renewable energy certificates. A summary of the facility description, DES's review of particulate and NOx emission rates and monitoring requirements, and recommended conditions of the approval are presented below.

Facility Description

Facility Name: Indeck Energy-Alexandria, LLC
Facility Location: 151 Smith River Road
Alexandria, NH 03222

Gross Nameplate Capacity: 16.5 MW
Began operation: Expected 1st Quarter 2009
Primary Fuel: Whole-tree wood chips, sawdust, and clean processed wood fuels

Particulate Emissions

New Hampshire Code of Administrative Rules Puc 2502.15, *"Eligible biomass technologies"*, requires that the facility meet an average particulate emission rate limit of 0.02 lb/MMBtu.

Emission Rate

A particulate emission test has not yet been performed for Indeck Energy-Alexandria. The emission test will be performed for total suspended particulate (TSP) using USEPA Method 5. The emission test will be observed and the results will be approved or denied by DES at a later date. The results of the test will indicate the actual TSP emission rate in lb/MMBtu and whether or not it meets the particulate Renewable Portfolio Standard (RPS) standard of 0.02 lb/MMBtu pursuant to RSA 362-F:2 VIII(a). DES anticipates that Indeck Energy-Alexandria will be able to meet the RPS standard.

Emissions Confirmation

Puc 2505.05(c), *Certification of Biomass Facilities*, requires facilities to conduct stack tests to verify compliance with the particulate RPS. Indeck Energy-Alexandria will need to perform future periodic particulate emission tests in accordance with Env-A 800, *Testing and Monitoring Procedures* on the schedule required by Puc 2505.05(c).

NOx Emissions

New Hampshire Code of Administrative Rules Puc 2502.15 requires that the facility meet a quarterly average NOx emission rate limit of 0.075 lb/MMBtu.

Emission Rate

Indeck Energy-Alexandria has not historically had NOx emission controls. However, as described below, Indeck Energy-Alexandria intends to install NOx emission control equipment and techniques to lower its NOx emissions.

DES issued Temporary Permit TP-B-0532 on February 4, 2008. DES anticipates that, if Indeck Energy-Alexandria proceeds with the modifications, that NOx emissions from the facility could meet the NOx RPS standard of 0.075 lb/MMBtu or less.

Emissions Confirmation

Indeck Energy-Alexandria will measure actual NOx emissions using a continuous emissions monitor (CEM). The CEM is required to be operated in accordance with Env-A 808, *Continuous Emissions Monitoring*, as specified in Condition VI, Table 5, Item #19 of Indeck Energy-Alexandria's Temporary Permit TP-B-0532. DES review of Indeck Energy-Alexandria's operational and testing data, including DES observation and review of Relative Accuracy Test Audits (RATA), will indicate if Indeck Energy-Alexandria operates the NOx CEM in accordance with all applicable requirements, and the CEM data is suitable for determining compliance with NOx emission limitations.

Conclusion and Recommended Conditions of Approval

DES believes that, with the modifications proposed by Indeck Energy-Alexandria, it will meet the requirements to be certified Class III - Existing Biomass/Methane renewable energy source. DES recommends that, with the following conditions, the PUC certify Indeck Energy-Alexandria as Class III renewable energy source eligible to generate renewable energy certificates:

1) Indeck Energy-Alexandria shall lower its NOx emissions to meet the 0.075 lb/MMBtu RPS. Indeck Energy-Alexandria has proposed to accomplish this by installing and operating the NOx emission controls specified in Temporary Permit TP-B-0532.

2) Indeck Energy-Alexandria shall perform emission tests for TSP in accordance with the procedures specified in Env-A 800 and schedule required by Puc 2505.05(c).

If you have any questions regarding DES's evaluation of the application or our conclusions, please contact me at joseph.fontaine@des.nh.gov or (603) 271-6794.

Sincerely

Joseph T. Fontaine
Trading Programs Manager
Air Resources Division

STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA)

BY AND BETWEEN

INDECK ENERGY-ALEXANDRIA, LLC

ISO NEW ENGLAND INC.

AND

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

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Attachment 2 – Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment
Attachment 3 – One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades
Attachment 4 – Milestones
Attachment 5 – Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs
Attachment 6 – Interconnecting Transmission Owner's Description of its Upgrades and Best Estimate of Upgrade Costs

THIS STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 3rd day of October, 2008, by and between Indeck Energy-Alexandria, LLC, a company organized and existing under the laws of the State of Delaware, ("Interconnection Customer" with a Small Generating Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator"), and Public Service Company of New Hampshire, a New Hampshire corporation organized and existing under the laws of the State of New Hampshire, ("Interconnecting Transmission Owner"). Under this Agreement the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

System Operator Information

System Operator: ISO New England Inc.
Attention: Project Manager – Generator Interconnections, Transmission Planning Department
Address: One Sullivan Road
City: Holyoke State: MA Zip: 01040-2841
Phone: 413-540-4220 Fax: 413-540-4203

Interconnecting Transmission Owner Information

Interconnecting Transmission Owner: Public Service Company of New Hampshire
Attention: Manager, Supplemental Energy Sources Department
Address: 780 North Commercial St, P. O. Box 330
City: Manchester State: NH Zip: 03105
Phone: 603-634-2311 Fax: 603-634-2449

Interconnection Customer Information

Interconnection Customer: Indeck Energy – Alexandria, LLC
Attention: Vice President, Asset Management
Address: 600 North Buffalo Grove Road, Suite 300
City: Buffalo Grove State: IL Zip: 60089
Phone: 847-520-3212 Fax: 847-520-9883

Interconnection Customer Application No: Queue Position No. 220
In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Interconnecting Transmission Owner's facilities that are part of the Administered Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Party.

1.4 Nothing in this Agreement is intended to affect any other agreement between the Parties.

1.5 <u>Responsibilities of the Parties</u>

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Interconnecting Transmission Owner shall construct, operate, and maintain its transmission facilities and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The

System Operator's Operating Representative:

System Operator: ISO New England Inc.
Attention: Project Manager – Generator Interconnections, Transmission Planning Department
Address: One Sullivan Road
City: Holyoke State: MA Zip: 01040-2841
Phone: 413-540-4220 Fax: 413-540-4203
E-mail: geninterconn@iso-ne.com

13.5 Changes to the Notice Information
A Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Interconnecting Transmission Owner

Public Service Company of New Hampshire:

By: JMA
Signer's name: James A. Muntz

Title: Senior Vice President - Transmission

Date: 9/30/08

For the Interconnection Customer

Indeck Energy-Alexandria, LLC:

By: ______________________
Signer's name: Michael D. Ferguson

Title: Vice President, Asset Management

System Operator's Operating Representative:

System Operator: ISO New England Inc.
Attention: Project Manager – Generator Interconnections, Transmission Planning Department
Address: One Sullivan Road
City: Holyoke State: MA Zip: 01040-2841
Phone: 413-540-4220 Fax: 413-540-4203
E-mail: geninterconn@iso-ne.com

13.5 Changes to the Notice Information
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Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Interconnecting Transmission Owner

Public Service Company of New Hampshire:

By: ____________________________
Signer's name: James A. Muntz

Title: Senior Vice President - Transmission

Date: ____________________________

For the Interconnection Customer

Indeck Energy-Alexandria, LLC:

By: Michael D. Ferguson
Signer's name: Michael D. Ferguson

Title: Vice President, Asset Management

Date: 9/30/08

For the System Operator

ISO New England Inc.

By: ______________________
Stephen J. Rourke

Title: Vice President, System Planning

Date: ______________________

Date: ______________________

For the System Operator

ISO New England Inc.

By: ______________________
Stephen J. Rourke

Title: Vice President, System Planning

Date: 10/3/2008

The State of New Hampshire

DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

July 21, 2008

Indeck Energy-Alexandria, LLC
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL 60089
Attn: Mike Ferguson, VP of Asset Management

Dear Mr. Ferguson,

This letter is sent with the intention to clarify that the shut down of the Alexandria Biomass Facility located in Alexandria New Hampshire occurred during November of 1994.

Since the date the Alexandria Facility was shutdown; no emissions were generated from the facility from that point until the present date.

If there are any further verification of information concerning this facility, please do not hesitate to contact me.

Sincerely,

Douglas C. Laughton

Douglas C. Laughton
Environmental Program Manager
Air Resources Division
N.H. Department of Environmental Services
P.O. Box 95
Concord, NH 03302-0095
(603) 271-6893

Attachment A

MONTHLY GENERATION KW HOURS

	GROSS	NET
1987		
November	90,900	80,000
December	90,900	80,000
1988		
January	5,738,700	5,050,000
February	7,147,700	6,290,000
March	6,443,200	5,670,000
April	9,431,800	8,300,000
May	9,818,200	8,640,000
June	10,034,100	8,830,000
July	7,659,100	6,740,000
August	9,979,500	8,782,000
September	10,454,500	9,200,000
October	11,404,500	10,036,000
November	7,045,500	6,200,000
December	12,234,090	10,766,000

		GROSS	NET
1989			
	January	11,054,500	9,728,000
	February	10,579,500	9,310,000
	March	11,284,100	9,930,000
	April	9,363,600	8,240,000
	May	6,909,100	6,080,000
	June	11,000,000	9,680,000
	July	9,909,100	8,720,000
	August	9,420,500	8,290,000
	September	12,000,000	10,560,000
	October	10,989,000	9,670,000
	November	10,272,700	9,040,000
	December	9,806,800	8,630,000
1990			
	January	10,000,000	8,800,000
	February	7,614,000	6,700,000
	March	6,261,400	5,510,000
	April	10,364,000	9,120,000
	May	10,965,900	9,650,000
	June	11,534,100	10,150,000
	July	12,011,400	10,570,000
	August	12,011,400	10,570,000
	September	11,261,400	9,910,000
	October	11,772,700	10,360,000
	November	11,363,600	10,000,000
	December	8,241,400	7,170,000

	GROSS	NET
1991		
January	11,389,200	9,920,000
February	10,309,300	9,000,000
March	11,392,400	9,900,000
April	9,656,400	8,430,000
May	10,630,000	9,280,000
June	11,966,100	10,590,000
July	12,418,100	10,990,000
August	11,155,200	9,850,000
September	11,943,200	10,510,000
October	12,462,900	10,930,000
November	12,075,300	10,590,000
December	9,076,400	7,960,000
1992		
January	12,364,300	10,930,000
February	11,806,700	10,260,000
March	12430500	10,011,000
April	10,871,000	9,610,000
May	12,392,800	10,980,000
June	11,968,300	10,580,000
July	11,313,700	9,990,000
August	12,406,800	10,980,000
September	11,900,500	10,520,000
October	7,576,400	6,690,000
November	11,585,500	10,230,000
December	12,271,900	10,860,000

		GROSS	NET
1993			
	January	12,285,100	10,860,000
	February	9,050,800	8,010,000
	March	12,328,500	10,960,000
	April	11,496,600	10,140,000
	May	11,832,090	10,500,000
	June	11,830,000	10,480,000
	July	6,500,000	5,610,000
	August	12,220,000	10,760,000
	September	12,000,000	10,680,000
	October	12,270,000	11,000,000
	November	11,980,000	10,620,000
	December	11,410,000	10,120,000
1994			
	January	~~12,221,000~~	10,867,000
	February	10,274,700	9,036,300
	March	11,864,600	10,467,800
	April	9,944,300	8,857,100
	May	11,476,200	10,173,000
	June	11,936,700	10,568,700
	July	11,913,600	10,538,200
	August	12,437,500	11,022,700
	September	11,668,500	10,358,100
	October	12,025,500	10,657,500

State of New Hampshire
Department of Environmental Services
Air Resources Division

Temporary Permit

Permit No: TP-B-0532
Date Issued: February 4, 2008

This certifies that:

Indeck Energy – Alexandria, LLC
600 N. Buffalo Grove Rd.
Buffalo Grove, IL 60089

has been granted a Temporary Permit for a:

Wood-fired Boiler with a Selective Non-Catalytic Reduction (SNCR) System and Cooling Tower

at the following facility and location:

Indeck Energy – Alexandria, LLC
151 Smith River Rd.
Alexandria, NH 03222
Facility ID Number: 3300900029
Application Number: FY07-0037

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 March 12, 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 August 31, 2009**.

COPY

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
CAS	Chemical Abstracts Service
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	Carbon Monoxide
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
MSDS	Material Safety Data Sheet
MW	megawatt
NAAQS	National Ambient Air Quality Standard
NG	Natural Gas
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standard
PM10	Particulate Matter < 10 microns
ppm	parts per million
psi	pounds per square inch
RACT	Reasonably Available Control Technology
RSA	Revised Statutes Annotated
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

The Indeck facility in Alexandria is a small electric power generating facility, producing 16 megawatts electricity gross rated capacity. The Indeck facility has a 250 MMBtu/hr gross heat input rate wood-fired boiler, which is a Zurn design, with a traveling grate, stoker type boiler. In addition, the facility has a large 2593 HP diesel emergency generator and a small diesel emergency fire pump engine rated at 300 HP. The facility was originally built in 1985 and 1986 and in operation from 1987 through some time in 1994 before being shut down. Since that time Indeck was issued Title V Operating Permit TV-OP-031 on September 28, 2000, which expired on September 30, 2005. During that time period and until this recent Temporary Permit application, approximately 13 years, the facility was never operated. Emissions from the facility have not been included in the state emissions inventory since 1994. Therefore, DES considers this facility as new construction. Also, note that the facility has a small diesel emergency fire pump, a Caterpillar Model 3208 generator, which was listed on its previous operating permit. Recently DES has changed its permitting requirements and does not require permits for emergency fire pumps.

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	Wood-fired Boiler	Zurn Burner Model SAO-24 Burner Serial # 3744B1	1987 Restarted 2007	250 MMBtu/hr ▪ Whole tree wood chips at approximately 50% moisture; ▪ Sawdust; ▪ Clean processed wood fuel[2]; and ▪ Any combination of whole tree wood chips and clean processed wood fuel ▪ No. 2 fuel oil (for startups only)
EU2	Boiler Cooling Tower	NA	1987 Restarted 2007	Drift factor = 0.00005 gal drift/gal circ. Circulation rate = 11,600 gpm

[1] The hourly fuel rates presented in Table 1 are set assuming a heating value of 4,500 Btu/lb for wood chips at 50% moisture 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.

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 of Pollution Control Equipment	Purpose	Emission Unit Controlled
EU1-PC1	Multi-cyclone	Control of large particulate matter	EU1
EU1-PC2	Electrostatic Precipitator (ESP)	Control of fine particulate matter	EU1
EU1-PC3	Selective Non-Catalytic Reduction System (SNCR)	Control of nitrogen oxides	EU1
EU1-PC4	Ammonia Scrubber	Control of ammonia slip emissions	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	EU1	150	5
2	EU3	30	1.5

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 Citation**
1	<u>*Precautions to Prevent, Abate, and Control Fugitive Dust*</u> 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
2	<u>*24-hour and Annual Ambient Air Limit – Boiler & Cooling Tower*</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).	Facility Wide	Env-A 1400
3	<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
4	<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

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
5	<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)
6	<u>*Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR) Program Avoidance*</u>[3] a. Facility wide emissions of CO[4] and TSP shall be limited to less than 250 tpy. b. Facility wide emissions of NOx shall be limited to less than 100 tpy.	Facility Wide	40 CFR 52.21(b)(1)(i)(b) (PSD avoidance) & Env-A 618 (NSR avoidance)
7	<u>*Prevention of Significant Deterioration (PSD) Avoidance*</u> To avoid the federal PSD program, emissions from EU1 (the Wood-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)
8	<u>*Maximum Gross Heat Input Rate*</u> The wood fired boiler is limited to a maximum gross heat input rate equal to 250 MMBtu/hr. This is equivalent to 161,000 lb/hr of steam production as averaged over any consecutive 24-hour period at 850 degrees F and 925 psig, assuming a boiler efficiency of 70% and boiler feedwater temperature of 430 degrees F.	EU1	Temporary Permit Application FY07-0037
9	<u>*Allowable Fuels for the Boiler*</u> The owner or operator is authorized to burn the following fuels in EU1: a. Whole tree chips at approximately 50% moisture (approximately 9.0 MMBtu/ton); b. Sawdust; c. Clean processed wood fuel (approximately 7.65 to 13.5 MMBtu/ton); d. Any combination of the above three fuels; and e. No. 2 fuel oil (for startups only).	EU1	Temporary Permit Application FY07-0037

[3] Uncontrolled emissions of CO, TSP, and NOx from the Boiler are greater than 250 tpy. The facility has decided to opt out of the PSD and NSR programs by installing pollution controls for these pollutants and accepting federally enforceable emissions limitations of 250 tpy for CO and TSP emissions and 100 tpy for NOx emissions.

[4] Note that the facility has voluntarily accepted an emissions limit of 0.15 lb CO/MMBtu in Table 4, Item 7, in order to avoid PSD program requirements, i.e., stay below 250 tpy CO emissions.

Table 4 - Operating and Emission Limitations			
Item #	Requirement	Applicable Emission Unit	Regulatory Citation
10	*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 capacity factor to less than 10%, which is equivalent to 1,564,400 gal/yr[5]; and b. The nitrogen content of No. 2 fuel oil combusted in the Boiler shall be less than 0.3% by weight.[6]	EU1	40 CFR 60 Subpart Db Section 60.44b(j) and (k)
11	*NOx Emission Limit Required for Generating Renewable Energy Certificates for the State of Connecticut*[7] 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 FY07-0037
12	*NOx RACT*[8] The owner or operator shall comply with a NOx emission rate of 0.33 lb/MMBtu based on a 24-hr calendar day average, for boilers firing wood or combination of wood and oil and equipped with a traveling, shaker, or vibrating grate.	EU1	Env-A 1211.04(d) & Env-A 1211.05(d)(5)a.
13	*SNCR Operational Requirement* 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 15.	EU1-PC3	Temporary Permit Application FY07-0037

[5] The annual capacity factor of 1,564,400 gal/yr, is based on a 12-month rolling average.
[6] Note that this sulfur content limit of 0.3% sulfur by weight is more stringent than the 0.4% sulfur by weight limit required by Env-A 1604.01(a)
[7] This NOx emission limit of 0.075 lb/MMBtu is a voluntary emission limit, which enables the facility to generate renewable energy certificates in Connecticut, and is not state-enforceable in New Hampshire. The Boiler must meet the 0.33 lb/MMBtu NOx RACT limit and stay below 57.0 lb/hr and less than 100 ton/yr NOx emissions limits with respect to meeting state enforceable limits in New Hampshire and federally enforceable limits with respect to avoidance of the federal PSD and NSR programs.
[8] The facility voluntarily chose to comply with a NOx emission limit of 0.075 lb/MMBtu (quarterly calendar average), listed in Table 4, Item 8, based on qualifying for a Renewable Portfolio Standard. This limit is a voluntary limit and is more stringent than the NSR avoidance limit in Table 4, Item 4 (100 tpy) and daily NOx limit listed in Table 4, Item 9 (0.33 lb/MMBtu).

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
14	*Ammonia Scrubber Operational Requirement* The ammonia scrubber system shall be operated to achieve continuous compliance with the ammonia slip emission limit in Table 4, Item 15. The owner or operator shall establish operating parameter ranges for the fresh water makeup and shower water flow during the initial startup, and they will be included in the renewal of this Permit.	EU1-PC4	Temporary Permit Application FY07-0037
15	*RTAP Operating Limitations* Ammonia slip stream emissions from the SCR system exiting through the Boiler stack shall be limited to less than or equal to 20 ppmvd at 7% oxygen to maintain compliance with the associated 24-hour and annual AAL for ammonia as set forth in Env-A 1450.01, *Table Containing the List Naming All Regulated Toxic Air Pollutants*.	EU1-PC3 & EU1	Env-A 1400[9]
16	*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 & EU3	Env-A 2002.02
17	*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)

[9] This ammonia slip stream emissions limit is more restrictive than what would be required to meet the ambient air limit for ammonia contained in Env-A 1400 (100 micrograms per cubic meter) and has been demonstrated to be feasible at all wood-fired power plants within the state of New Hampshire.

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
18	*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. Were 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)
19	*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)
20	*Particulate Matter Pollution Control Equipment* The multiclone and electrostatic precipitator (EU1-PC1 and EU1-PC2) shall be fully operational upon facility startup and shall not be bypassed during startup, operation, or shutdown of the steam generating unit.	EU1-PC1 & EU1-PC2	Temporary Permit Application FY07-0037

Table 4 - Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
21	*NSPS Opacity Standards* The average opacity (6-minute average) shall not be greater than 20% opacity, except for one 6-minute period per hour of not more than 27% opacity.	EU1	40 CFR 60 Subpart Db Section 60.43b(f)
22	*NSPS Particulate Matter Emission Limit*[10] The total suspended particulate matter (TSP) emissions shall be less than or equal to 0.03 lb/MMBtu for any affected facility that commences construction, reconstruction, or modification after February 28, 2005.	EU1	40 CFR 60 Subpart Db Section 60.43b(h)(1)
23	*NSPS Exemptions for Particulate Matter and Opacity Standards* The 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) & Section 60.46b(a)
24	*Sulfur Content of No. 2 Fuel Oil* The sulfur content of No. 2 fuel oil shall not exceed 0.4% sulfur by weight.	Facility Wide	Env-A 1604.01(a)

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[10] This limit is more stringent than the limits of 0.10 lb/MMBtu for gross heat input rates greater than 250 MMBtu/hr and 0.15 lb/MMBtu for gross heat input rates greater than 100 MMBtu/hr and less than 250 MMBtu/hr, as contained in Env-A 2002.08.

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 Citation
1	Initial Performance Test for Particulate Matter and Opacity	In accordance with 40 CFR 60 Section 60.46b(b), in order to determine compliance with the particulate matter emission limits and opacity limits under 40 CFR 60.43b, the owner or operator is required to conduct an initial performance test as required under 40 CFR 60, Subpart A, Section 60.8(a) using the following procedures and reference methods: a. Method 3B is used for gas analysis when applying Method 5 or Method 17; b. Method 5 shall be used to measure the concentration of particulate matter; c. Method 1 is used to select the sampling site and the number of transverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors; d. For Method 5, the temperature of the sample gas in the probe and filter holder is monitored and maintained at 320 +/- 25 deg F; e. For determination of particulate matter emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Method 5 by traversing the duct at the same sampling location; f. For each run using Method 5, the emission rate expressed in nanograms per joule heat input is determined using: the oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section, the dry basis F factor, and the dry basis emission rate calculation procedure contained in Method 19; and g. Method 9 is used for determining opacity.	Within 60 days after achieving the maximum production rate and not later than 180 days after initial startup	EU1	40 CFR 60 Subpart Db Section 60.46b(d) & 40 CFR 60 Subpart A Section 60.8

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
2	Initial Performance Test	The performance test of the Boiler 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.	Within 60 days after achieving the maximum production rate and not later than 180 days after initial startup	EU1	40 CFR 60 Subpart A Section 60.8(c) & Env-A 802.10
3	Number of Runs for a Complete Test	Each performance test shall consist of three separate runs using the applicable test method.	As specified	EU1	40 CFR 60 Subpart A Section 60.8(f)
4	Initial Performance Test	The owner or operator is required to conduct an initial performance test of the Boiler in order to determine compliance with the ammonia (NH_3) slip, NOx, CO, SO_2, TSP, and VOC emissions limitations in this permit. In addition, DES is requiring filterable and condensible PM_{10} emissions testing to be conducted for informational purposes. Testing shall be conducted in accordance with Table 5, Items 2, 3, and 5-7.	Within 60 days of achieving the maximum production rate of the device, but not later than 180 days from startup of the device	EU1	Env-A 802

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
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; b. 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; c. A test report shall be submitted to the Division within 60 days after the completion of testing; and d. The Owner or Operator shall be subject to fees for any testing and monitoring which Division personnel undertake or audit in accordance with this permit.	Each test	EU1	Env-A 802 & Env-A 704.02
6	General Stack Testing Requirements	The following test methods, or Division approved alternatives, shall be used: a. Methods 1 & 2 to determine the exit velocity of stack gases; b. Method 3 or 3A to determine carbon dioxide, oxygen, excess air, and molecular weight (dry basis) of stack gases; c. Method 4 to determine moisture content (volume fraction of water vapor) of stack gases; d. Methods 5, 201A, and 202 to determine total suspended particulate matter, filterable PM_{10}, and condensible PM_{10} emissions; e. Method 7E to determine NOx emissions; f. Method 9 to determine opacity; g. Method 10 to determine CO emissions; h. Method 25 or 25A or 25B to determine non-methane VOCs; and i. Conditional Test Method CTM-027 to determine ammonia slip emissions.	Each test	EU1	Env-A 802

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
7	Use of Alternative Methods During a Test	The Division shall approve deviations from the agreed-upon test method or pre-test protocol if the following criteria are met: a. The owner or operator informs division personnel assigned to the stack test of the following: 1. The deviation from the testing method or planned operational mode of the source; 2. The reason(s) for the deviation; 3. The implications of such a deviation; and 4. The owner or operator provides technical justification showing that allowance of such deviation will not affect the accuracy of the compliance stack emissions test.	As specified	EU1	Env-A 802.09
8	Compliance Stack Testing for NO_x	The owner or operator of a new source or device subject to NO_x RACT requirements in Env-A 1211 is required to conduct NO_x RACT compliance testing within 60 days of achieving the maximum production rate but not later than 180 days from startup.	Within 60 days of achieving the maximum production rate but not later than 180 days from startup	EU1	Env-A 803.02(a), (b)
9	NO_x Test Methods	The owner or operator shall use test methods contained in Env-A 803.02(e)(1)-(5) or (f), as applicable, for the initial NOx performance test.	Initial performance test	EU1	Env-A 803.02(e)-(f)
10	Additional Stack Testing	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

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
11	Multiclone Monitoring Requirements	a. Conduct monitoring of pressure differential across the Multiclone (EU1- PC1) unit every two hours. An acceptable pressure differential shall be in accordance with standard operating practices and manufacturer's recommended operating parameters, and shall be maintained between 3 and 7 inches of water column. b. Pressure differential readings shall be recorded on standard forms and kept on file at the facility for review by the DES upon request. The standard forms shall include the acceptable operating parameters for quick reference by facility personnel. c. During down-time maintenance periods, facility personnel shall inspect inlet and outlet vanes and boots for any build up of caked dust. All caked dust shall be removed during each down-time maintenance period. d. Observations of operating parameters outside of the standard operating practices included in this permit shall be recorded, investigated, and corrected immediately.	Every 2 hours and as specified	EU1-PC1	RSA 125-C:6, XI

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
12	ESP Monitoring Requirements	In accordance with Indeck's O&M manual and standard operating practices for this equipment, on a bi-hourly basis, facility personnel shall: a. Check and record the primary voltage and pressure drop readings on the ESP. The primary voltage shall be maintained between 45 and 55 kva and the pressure drop across the ESP shall be maintained between 0 and 2 inches of water column. Voltage or pressure drop readings outside these ranges indicate a malfunction with the ESP and the operator shall correct the malfunction immediately. b. The facility operator shall respond to all equipment alarms immediately. c. Bi-hourly monitoring data shall be recorded daily on standard forms and kept on file at the facility for review by the DES upon request. The standard forms shall include the acceptable operating parameters for quick reference by facility personnel. d. Observations of operating parameters outside of the standard operating practices included in this permit shall be recorded, investigated, and corrected immediately.	Every 2 hours and daily as specified	EU1-PC2	RSA 125-C:6, XI
12	ESP Monitoring Requirements (Cont'd)	Daily Monitoring/Testing Requirements: a. The ESP shall be inspected at least once each shift. The casing, piping, and ducts shall be inspected for leaks, abnormal noise, hot spots, and fires. Local instrumentation shall be monitored for normal values. The local control panel shall be monitored for proper indication of normal values and alarms. b. Observations of operating parameters outside of the standard operating practices included in this permit shall be recorded, investigated, and corrected immediately.	Daily	EU1-PC2	RSA 125-C:6, XI
13	Ammonia Flow to the Boiler (SNCR System)	The total ammonia flow to the Boiler shall be continuously monitored using a DES approved ammonia flow meter. Ammonia usage shall be recorded daily.	Continuous & daily calculations	EU1-PC3	RSA 125-C:6, XI

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
14	Fresh Water Makeup and Total Shower Flow to the Ammonia Scrubber	The fresh water makeup and total shower flow to the ammonia scrubber shall be continuously monitored using DES approved monitors. The owner or operator shall establish the operating parameter ranges for these two process variables during the initial startup and during performance testing to demonstrate continuous compliance with the 20 ppmvd at 6% oxygen ammonia slip emission limit contained in Table 4, Item 15.	Continuous	EU1-PC4	RSA 125-C:6, XI
15	Ammonia Flow/NOx Emission Rate Comparison	The owner or operator shall calculate and record the average daily ammonia flow rate in lb/hr based on the ammonia flow meter and compare that to the average daily NOx emission rate in lb/hr based on the NOx CEM data.	Daily	EU1 & EU1-PC3	RSA 125-C:6, XI
16	Ammonia Slip Emissions Testing	The owner or operator shall conduct initial and annual ammonia stack testing requirements for the SCR System in accordance with Items 1 through 7 in this Table, as applicable.	Initial performance test and annually thereafter	EU1	RSA 125-C:6, XI
17	Opacity COMS Monitoring Requirements	The owner or operator subject to the opacity standard under Section 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 procedures under Section 60.13(h) shall be followed for installation, evaluation, and operation of the continuous monitoring systems. The span value shall be between 60 and 80 percent.	Continuous	Opacity COMS on EU1	40 CFR 60 Subpart Db Section 60.48b(a) and (e)(1)
18	Opacity COMS Monitoring Requirements	The COMS shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 1 and Env-A 808.03(a)-(c), as applicable. Determination of compliance with opacity emission limits established in Table 4 of this permit shall be made by the facility COMS or visible emission readings taken once per shift following the procedures specified in 40 CFR 60, Appendix A, Method 9. Calculations shall be performed as specified in Table 5 Item 28.	Continuous	Opacity COMS on EU1	40 CFR 60, Appendix B, Performance Specification 1 & Env-A 807 & 808

Table 5 - Monitoring and Testing Requirements					
Item #	Parameter	Method of Compliance	Frequency	Applicable Unit	Regulatory Citation
19	NOx CEMS Monitoring Requirements	The NOx CEM system shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 2 and Env-A 808.03(a)-(c), as applicable. Determination of compliance with NOx emission limits established in Table 4 of this permit shall be made by the facility NOx CEM. The NOx emission rate shall be calculated daily in lb/hr averaged over the calendar day 24-hour period and calculated daily in lb/MMBtu averaged over the calendar day 24-hour period. Calculations shall be performed as specified in Table 5, Item 28.	Continuous	NOx CEM on EU1	40 CFR 60, Appendix B, Performance Specification 2 & Env-A 808
20	CO CEMS Monitoring Requirements	The CO CEM system shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 4 and Env-A 808.03(a)-(c), as applicable. Determination of compliance with CO emission limits established in Table 4 of this permit shall be made by the facility CO CEM. The CO emission rate shall be calculated daily in lb/hr averaged over the calendar day 24-hour period and calculated daily in lb/MMBtu averaged over the calendar day 24-hour period. Calculations shall be performed as specified in Table 5, Item 28.	Continuous	CO CEM on EU1	40 CFR 60, Appendix B, Performance Specification 4 & Env-A 808
21	Carbon Dioxide (CO_2) or oxygen (O_2) CEMS Monitoring Requirements	The CO_2 or O_2 CEM shall meet the requirements of 40 CFR 60, Appendix B, Performance Specification 3 and Env-A 808.03(a)-(c), as applicable.	Continuous	CO_2 or O_2 CEM on EU1	40 CFR 60, Appendix B, Performance Specification 3 & Env-A 808
22	Stack Volumetric Flow Continuous Monitoring Requirements	The continuous emission monitoring system (CEM) for the stack volumetric flow shall meet all of the requirements of 40 CFR 60, Appendix B, Performance Specification 6 and Env-A 808.03(d). The stack flow monitor shall have an automatic blow-back purge system installed and activated, at all times, during boiler operation. The stack volumetric flow measuring device combined with the NOx and CO concentration obtained from the NOx and CO CEM's shall be used to calculate mass emission rates for comparison with the emission standards specified in Table 4.	Continuous	Stack Volumetri c Flow CEM	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 Citation**
23	QA/QC Plan Requirements	The Permittee required to operate or maintain an opacity or gaseous CEM system 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; and 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
24	General Audit Requirements	a. Required quarterly audits shall be done anytime during each calendar quarter, but successive quarterly audits shall occur no more than 4 months apart; and b. The Permittee shall notify the division at least 30 days prior to the performance of a RATA.	Quarterly	EU1	Env-A 808.07
25	Gaseous CEM Audit Requirements	Audit requirements for 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
26	Opacity CEM Audit Requirements	Audit requirements for 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

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
27	Data Availability Requirements	a. The owner or operator shall operate the CEM 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. b. 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. c. 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
28	Calculations of CEM 24-hour Calendar Day Averages	24-hour calendar day averages shall be calculated as follows: a. 24-hour calendar day average=(Sum of all valid hour lb/MMBtu or lb/hr averages for the calendar day)/(24 hours – hours of CEM system downtime for the day); b. 24-hour 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.)	N/A	EU1	40 CFR 60, Appendix B, & Env-A 808

Table 5 - Monitoring and Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency**	**Applicable Unit**	**Regulatory Citation**
29	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
30	Sulfur Content of Liquid Fuels	Conduct testing in accordance with appropriate ASTM test methods or retain delivery tickets in accordance with Table 6, Item #6 in order to demonstrate compliance with the sulfur content limitation provisions specified in this permit for liquid fuels.	For each delivery of fuel oil to the facility	Facility Wide	Env-A 806.02 & Env-A 806.05
31	SNCR Operating Temperature	The owner or operator shall continuously monitor and record the SNCR Operating Temperature in the Boiler combustion zone and calculate and record hourly and daily (24-hr calendar day) averages of the SNCR Operating Temperature.	Continuous, calculate and record hourly and daily (24-hr calendar day) averages	EU1	Env-A 604.02(a)(3)

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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 Citation**
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 902.01(a)
2	*Regulated Toxic Air Pollutants* Determine compliance with the AALs by using one of the methods provided in Env-A 1405. Documentation for the demonstration of compliance shall be retained at the facility, and shall be made available to the Division for inspection.	Maintain Current Data	Facility Wide	Env-A 1405.01
3	*Monitoring Data* The owner or operator shall maintain records of monitoring requirements as specified in Table 5 of this Permit including, but not limited to: a. Maintenance and repair records for EU1 and the pollution control equipment listed in Table 2 (multiclone, ESP, SNCR system, and ammonia scrubber); b. Maintenance and repair records of the CEM and COM systems; c. Maintenance, calibration, and repair records associated with the steam flow and stack volumetric flow measuring devices; and d. Stack test results for all pollutants tested.	Maintain on a continuous basis	Facility Wide	Env-A 906
4	*General Recordkeeping Requirements for Process Operations* Maintain the following records of operating data from the Cooling Tower for the Boiler: a. Circulating water flow (gal/min and gal/day); b. Total Dissolved Solids concentration (ppm); c. Chemical additives flow (gal/min and gal/day); d. MSDS sheets for all chemical additives; and e. Hours of operation per day of the Cooling Tower.	Monthly	EU2	Env-A 903.02
5	*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. diesel fuel, whole tree chips, clean processed wood chips) and amount of fuel burned in each device, or type and amount of fuel burned in multiple devices and hours of operation of each device to be used to apportion fuel use between the multiple devices; and b. Sulfur content of any liquid fuel burned in terms of percent sulfur by weight.	Monthly	EU1	Env-A 903.03

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Citation**
6	*Liquid Fuel Oil Recordkeeping Requirements* In lieu of sulfur testing pursuant to Table 5, Item 30, 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
7	*Recordkeeping Requirements for the SNCR System* For the SNCR System, 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; and c. Daily calculated ratio of the Average daily ammonia flow (lb/hr) to average daily NOx flow (lb/hr) ratio; d. Hourly average and daily average SNCR Operating Temperature for each operating day; and e. Maintenance performed on the SNCR system.	Daily	EU1 & EU1-PC3	Env-A 906
8	*Recordkeeping Requirements for the Ammonia Scrubber System* For the ammonia scrubber system, the owner or operator shall keep records of the following information in accordance with the required timeframes: a. Average daily fresh water makeup flow in gal/min; b. Average daily shower water flow to the scrubber; and c. Average daily level in the scrubber in ft or % of scale.	Daily	EU1 & EU1-PC4	Env-A 906
9	*General NO_x Recordkeeping Requirements* 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 Current Data	Facility Wide	Env-A 905.02

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Citation**
10	*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	EU1-PC3	Env-A 905.03
11	*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)
12	*NSPS Opacity Recordkeeping Requirement* The owner or operator shall maintain records of opacity.	Continuous	EU1	40 CFR 60 Subpart Db Section 60.49b(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)

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Citation**
14	*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)
15	*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[11] following the date of such measurements, maintenance, reports, or records.	Continuous	EU1	40 CFR 60 Subpart A Section 60.7(f)
16	*Additional Recordkeeping Requirements: Boiler Emission Limitations* Maintain a 12-month running total of Boiler emissions of NOx, SO2, TSP, CO, and VOC each month, for the purpose of demonstrating that the emissions of these pollutants from the Boiler are below the permit limits specified in Table 4.	Monthly	EU1	Env-A 906
17	*Additional Recordkeeping Requirements: Facility Wide Emission Limitations* Maintain a 12-month running total of the combined facility wide emissions of NOx, SO2, TSP, CO, and VOC each month, for the purpose of demonstrating that the total combined emissions of these pollutants are below the permit limits specified in Table 4.	Monthly	Facility Wide	Env-A 906

[11] 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.

Table 6 - Recordkeeping Requirements				
Item #	**Requirement**	**Duration/ Frequency**	**Applicable Unit**	**Regulatory Citation**
18	*CEMS and COMS Records* For each CEM and COM system at the facility, the owner or operator shall keep the records of emission data recorded by the CEM or COM system, including: a. 24-hour calendar daily averages of NOx in lb/hr, lb/MMBtu, and part per million (ppm) dry, whether or not an excess emissions has occurred; b. 24-hour calendar daily averages of CO in lb/hr, lb/MMBtu, and part per million (ppm) dry, whether or not an excess emissions has occurred; c. 24-hour calendar daily averages of percentage of CO_2 or O_2 on a wet basis. d. 24-hour calendar daily averages of percentage of opacity; e. 24-hour calendar daily averages of steam generation rate; f. 24-hour calendar daily averages of stack flow (dscfm); g. CEM or COM system data availability data; and h. Quarterly CEM/COM audit results.	Maintain on a continuous basis	EU1	Env-A 903.04(a) & Env-A 808

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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 Citation**
1	*Annual Emissions Report* Submit an annual emissions report which shall include the following information: a. Actual calendar year emissions from each device of NO_x, CO, SO_2, TSP, VOC, HAP, and RTAPs speciated by individual RTAP (ammonia from the Boiler and other RTAPs from the cooling tower); 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 5.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.01
2	*NO_x Emission Statements Reporting Requirements* The owner or operator shall submit the following information with the annual emission report: a. A break down of NO_x emissions reported pursuant to Table 7, Item 1 by month; and b. All data recorded in accordance with Table 6, Item 7.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 909
3	*Reporting of Monthly 12-Month Rolling Total Emissions* The owner or operator will also include the following information with the annual emissions report to show compliance with its 12-month rolling total emissions caps for the Boiler alone and 12-month rolling total emissions caps Facility Wide: a. Each monthly, 12-month rolling total of NOx, CO, SO_2, TSP, and VOC emissions from the Boiler alone; and b. Each monthly, 12-month rolling total of Facility Wide combined NOx, CO, SO_2, TSP, and VOC emissions.	Annually (no later than April 15th of the following year)	EU1 & Facility Wide	Env-A 910

Table 7 - Reporting Requirements				
Item #	Requirement	Frequency	Applicable Emission Unit	Regulatory Citation
4	<u>*NSPS Initial Startup Notification*</u> Submit the initial notification to DES and EPA Region 1 of the initial startup, including all of the information specified below. a. The design heat input capacity of the boiler; and b. Identification of fuels to be combusted in the boiler. The address for USEPA Region 1 is: USEPA Region 1 Attn: Air Compliance Clerk 1 Congress Street Suite 1100 Mail Code SEA Boston, MA 02114-2023	Within 15 days of initial startup	EU1	40 CFR 60 Subpart Db Section 60.49b(a)
5	<u>*Reporting of NSPS Performance Test Results*</u> Submit to DES and EPA Region 1 performance test data from the Boiler for particulate matter and opacity and the performance evaluation of the COMS for opacity using the applicable performance specifications in 40 CFR 60 Appendix B.	Within 60 days of completion of stack testing	EU1	40 CFR 60 Subpart Db Section 60.49b(b) & Env-A 802.11(a)
6	<u>*NSPS Annual Capacity Factor Reporting*</u> 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	<u>*NSPS Very Low Sulfur Oil Recordkeeping and Reporting Requirement*</u> 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)

Table 7 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Emission Unit**	**Regulatory Citation**
8	<u>*SNCR System Reporting Requirements*</u> For the SNCR System, 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 the average daily ammonia flow (lb/hr) to average daily NOx flow (lb/hr); d. Daily (24-hr calendar day) average SNCR Operating Temperature for each day of operation; and e. Maintenance performed on the SNCR system.	Quarterly, no later than 30 days following the end of each calendar quarterly reporting period	EU1-PC3	Env-A 910
9	<u>*Quarterly Excess Emissions Report*</u>[12] The owner or operator is required to provide the following in each quarterly emission report specified in Env-A 808.11: a. The information specified in 40 CFR 60.7(c): 1. The magnitude of excess emissions computed in accordance with Section 60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. 2. Specific identification of each period of excess emissions that occurs during startup, shutdown, or malfunctions of the Boiler. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. 3. The date and time identifying each period during which the CEMS was inoperative except for zero and span checks and the nature of the system repairs or adjustments. 4. When no excess emissions have occurred or the CEMs have not been inoperative, repaired, or adjusted, such information shall be stated in the report. b. The daily averages of gaseous CEM measurements and calculated emission rates; and	Quarterly, no later than 30 days following the end of each calendar quarterly reporting period	EU1	Env-A 808.11, 808.12, 808.13, & 40 CFR 60 Subpart Db Section 60.49b(h)

[12] 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 Citation**
	Quarterly Excess Emissions Report (continued) c. The information required by Env-A 808.13(a)(5) through (9) listed below: 1. If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: a) The date and time of the beginning and ending of each period when the CEM was inoperative; b) The reason why the CEM was not operating; c) The corrective action taken; and d) The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or pollutant analyzer in the CEM system; 2. For all "out of control periods" as defined in Env-A 808.01(g) and 40 CFR 60 Appendix F, the following information: a) The times beginning and ending the out of control period; b) The reason for the out of control period; and c) The corrective action taken; 3. The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating; 4. The span value, as defined in Env-A 101.255, of each analyzer in the CEM system and units of measurement for each instrument; and 5. When calibration gas is used, the following information: a) The calibration gas concentration; b) If a gas bottle was changed out during the quarter: i) The date of the calibration gas bottle change; ii) The gas bottle concentration before the change; and iii) The gas bottle concentration after the change; and c) The expiration date for all calibration gas bottles used.	Quarterly, no later than 30 days following the end of each calendar quarterly reporting period	EU1	Env-A 808.11, 808.12, & 808.13

Table 7 - Reporting Requirements				
Item #	**Requirement**	**Frequency**	**Applicable Emission Unit**	**Regulatory Citation**
10	<u>*Emission-Based Fees*</u> Pay emission-based fees in accordance with Condition XI.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 700

IX. Permit Deviation Recordkeeping and Reporting Requirements

A. 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.

B. Env-A 911.03, *Recordkeeping Requirements:* In the event of a permit deviation, the owner or operator of the affected device, process, or air pollution control equipment shall:

1. 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
2. Record the following information:
   a. The permit deviation;
   b. The probable cause of the permit deviation;
   c. The date of the occurrence;
   d. The duration;
   e. The specific device that contributed to the permit deviation;
   f. Any corrective or preventative measures taken; and
   g. The amount of any excess emissions that occurred as a result of the permit deviation, if applicable.

C. Env-A 911.04, *Reporting Requirements:*

1. If the permit deviation does <u>not</u> cause excess emissions but continues for a period greater than 9 consecutive days, the owner or operator shall notify the department by telephone (603-271-1370), electronic mail (pdeviations@des.state.nh.us), or fax (603-271-1381) on the tenth day of the permit deviation, unless it is a Saturday, Sunday, or state legal holiday, in which event the department shall be notified on the next day which is not a Saturday, Sunday, or state legal holiday.
2. In the event of a permit deviation that causes excess emissions, the owner or operator of the affected device, process, or air pollution control equipment shall notify the department of the permit deviation and excess emissions by telephone (603-271-1370), electronic mail (pdeviations@des.state.nh.us), or fax (603-271-1381), within 24 hours of discovery of the

permit deviation, unless it is a Saturday, Sunday, or state legal holiday, in which event the department shall be notified on the next day which is not a Saturday, Sunday, or state legal holiday; and submit a written report, in accordance with C.4 below, to the department within 10 days of discovery of the permit deviation reported above.

3. In the event of a permit deviation caused by a failure to comply with the data availability requirements of Env-A 800, the owner or operator of the affected device, process, or air pollution control equipment shall:

   a. Notify the department of the permit deviation by telephone, electronic mail, or fax, within 10 days of discovery of the permit deviation; and
   b. Report the permit deviation to the department as part of the excess emissions report submitted in accordance with Env-A 800.

4. The written report to be submitted pursuant to C.2, above, shall include the following information:

   a. Facility name;
   b. Facility address;
   c. Name of the responsible official employed at the facility;
   d. Facility telephone number;
   e. Date(s) of the occurrence;
   f. Time of the occurrence;
   g. Description of the permit deviation;
   h. The probable cause of the permit deviation;
   i. Corrective action(s) taken to date;
   j. Preventative measures taken to prevent future occurrences;
   k. 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;
   l. The specific device, process or air pollution control equipment that contributed to the permit deviation;
   m. The type and quantity of excess emissions emitted to the atmosphere due to the permit deviation; and
   n. The calculation or estimation used to quantify the excess emissions.

D. Env-A 911.05, *Reporting Permit Deviations*:

1. In accordance with 40 CFR Part 70.6(a)(3)(iii)(A), sources subject to Env-A 609 shall report to the department, at a reporting frequency no less than semi-annually, the following information:

   a. A summary of all permit deviations previously reported to the department pursuant to Conditions C.1 and 2 above (Env-A 911.04(a) and (b)), for the reporting period; and
   b. A list of all permit deviations recorded pursuant to Condition B.2 above (Env-A 911.03(b)).

X. 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.

XI. 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 XI.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 and the NO_x emissions reduction fund 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.