RIPUC Use Only	
Date Application Received:	__ __/__ __/__ __
Date Review Completed:	__ __/__ __/__ __
Date Commission Action:	__ __/__ __/__ __
Date Commission Approved:	__ __/__ __/__

GIS Certification #: ____________________

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM

The Standard Application Form
Required of all Applicants for Certification of Eligibility of Renewable Energy Resource
(Version 6 – January 21, 2008)

STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISSION
Pursuant to the Renewable Energy Act
Section 39-26-1 et. seq. of the General Laws of Rhode Island

NOTICE:

When completing this Renewable Energy Resources Eligibility Form and any applicable Appendices, please refer to the State of Rhode Island and Providence Plantations Public Utilities Commission Rules and Regulations Governing the Implementation of a Renewable Energy Standard (RES Regulations, Effective Date: January 1, 2006), and the associated RES Certification Filing Methodology Guide. All applicable regulations, procedures and guidelines are available on the Commission's web site: www.ripuc.org/utilityinfo/res.html. Also, all filings must be in conformance with the Commission's Rules of Practice and Procedure, in particular, Rule 1.5, or its successor regulation, entitled "Formal Requirements as to Filings."

• Please complete the Renewable Energy Resources Eligibility Form and Appendices using a typewriter or black ink.

• Please submit one original and three copies of the completed Application Form, applicable Appendices and all supporting documentation to the Commission at the following address:

Rhode Island Public Utilities Commission
89 Jefferson Blvd
Warwick, RI 02888
Attn: Renewable Energy Resources Eligibility

In addition to the paper copies, electronic/email submittals are required under Commission regulations. Such electronic submittals should be sent to: Luly E. Massaro, Commission Clerk at lmassaro@puc.state.ri.us

• In addition to filing with the Commission, Applicants are required to send, electronically or electronically and in paper format, a copy of the completed Application including all attachments and supporting documentation, to the Division of Public Utilities and Carriers and to all interested parties. A list of interested parties can be obtained from the Commission's website at www.ripuc.org/utilityinfo/res.html.

• Keep a copy of the completed Application for your records.

• The Commission will notify the Authorized Representative if the Application is incomplete.

• Pursuant to Section 6.0 of the RES Regulations, the Commission shall provide a thirty (30) day period for public comment following posting of any administratively complete Application.

• Please note that all information submitted on or attached to the Application is considered to be a public record unless the Commission agrees to deem some portion of the application confidential after consideration under section 1.2(g) of the Commission's Rules of Practice and Procedure.

• In accordance with Section 6.2 of the RES Regulations, the Commission will provide prospective reviews for Applicants seeking a preliminary determination as to whether a facility would be eligible prior to the formal certification process described in Section 6.1 of the RES Regulations. Please note that space is provided on the Form for applicant to designate the type of review being requested.

• Questions related to this Renewable Energy Resources Eligibility Form should be submitted in writing, preferably via email and directed to: Luly E. Massaro, Commission Clerk at RES@puc.state.ri.us

SECTION I: Identification Information

1.1 Name of Generation Unit (sufficient for full and unique identification):
Indeck Alexandria Energy Center

1.2 Type of Certification being requested (check one):

X ❑ Standard Certification ❑ Prospective Certification (Declaratory Judgment)

1.3 This Application includes: (Check all that apply)[1]

❑ APPENDIX A: Authorized Representative Certification for Individual Owner or Operator
❑ APPENDIX B: Authorized Representative Certification for Non-Corporate Entities Other Than Individuals
❑ X APPENDIX C: Existing Renewable Energy Resources
❑ APPENDIX D: Special Provisions for Aggregators of Customer-sited or Off-grid Generation Facilities
❑ APPENDIX E: Special Provisions for a Generation Unit Located in a Control Area Adjacent to NEPOOL
❑ X APPENDIX F: Fuel Source Plan for Eligible Biomass Fuels

1.4 Primary Contact Person name and title: _____Stephanie Hamilton _________
_______________Legal Affairs and Compliance_______________________

1.5 Primary Contact Person address and contact information:
Address: _______Conservation Services Group__________________________________
____________40 Westborough MA, 01581__________________________
____
Phone: ___508-836-9500__ext. 13285 Fax: 508-836-3181
Email: ____stephanie.hamilton@csgrp.com___________________________

1.6 Backup Contact Person name and title: ___Deborah Razza________________
_____Sales and Operations_________

1.7 Backup Contact Person address and contact information:
Address: __________Conservation Services Group_____________________________
________________40 Westborough MA, 01581_____________________
____
Phone: __508-365-3386___ Fax: ___508-836-3181________
Email: Deborah.Razza@csgrp.com__________________________________

[1] Please note that all Applicants are required to complete the Renewable Energy Resources Eligibility Standard Application Form and all of the Appendices that apply to the Generation Unit or Owner or Operator that is the subject of this Form. Please omit Appendices that do not apply.

1.8 Name and Title of Authorized Representative (*i.e.*, the individual responsible for certifying the accuracy of all information contained in this form and associated appendices, and whose signature will appear on the application):
______________Patricia Stanton, Vice President Clean Energy Markets
Conservation Services Group

Appendix A or B (as appropriate) completed and attached? ❑ Yes ❑ No x❑ N/A

1.9 Authorized Representative address and contact information:
Address: _________40 Washington Street______________________
________________Westborough MA, 01581____________________________

Phone: 508-836-9500_______ Fax: ____508-836-3181_____
Email: ________pat.stanton@csgrp.com________________________

1.10 Owner name and title: ______Indeck Energy-Alexandria, LLC
________________Mike Ferguson, Vice President Asset Management

1.11 Owner address and contact information:
Address: Indeck Energy Services ______
_______600 North Buffalo Grove Road, Suite 300
_________Buffalo Grove, IL 60089__________________
Phone: _(847) 520-9883 Fax: ___(847) 520-9883
Email: __mferguson@indeckenergy.com

1.12 Owner business organization type (check one):
❑ Individual
❑ Partnership
❑ X Corporation
❑ Other: ____

1.12 1.13 Operator name and title: ___ Indeck Energy-Alexandria, LLC
Harry Smith, Plant Manager

1.14 Operator address and contact information:
Address: _______151 Smith River Road__________
______________Alexandria, NH 03222___________________________

Phone: __(603) 744-6355________ Fax: _(603)744-6802___
Email: hsmith@indeckenergy.com

1.15 Operator business organization type (check one):
❑ Individual
❑ Partnership
❑ X Corporation
❑ Other: ____

SECTION II: Generation Unit Information, Fuels, Energy Resources and Technologies

2.1 ISO-NE Generation Unit Asset Identification Number or NEPOOL GIS Identification Number (either or both as applicable): ____1631__________________________

2.2 Generation Unit Nameplate Capacity: ____16___ MW

2.3 Maximum Demonstrated Capacity: __16 ___ MW

2.4 Please indicate which of the following Eligible Renewable Energy Resources are used by the Generation Unit: (Check ALL that apply) – *per RES Regulations Section 5.0*

- ❑ Direct solar radiation
- ❑ The wind
- ❑ Movement of or the latent heat of the ocean
- ❑ The heat of the earth
- ❑ Small hydro facilities
- ❑ X Biomass facilities using Eligible Biomass Fuels and maintaining compliance with all aspects of current air permits; Eligible Biomass Fuels may be co-fired with fossil fuels, provided that only the renewable energy fraction of production from multi-fuel facilities shall be considered eligible.
- ❑ Biomass facilities using unlisted biomass fuel
- ❑ Biomass facilities, multi-fueled or using fossil fuel co-firing
- ❑ Fuel cells using a renewable resource referenced in this section

2.5 If the box checked in Section 2.4 above is "Small hydro facilities", please certify that the facility's aggregate capacity does not exceed 30 MW. – *per RES Regulations Section 3.31*

❑ ← check this box to certify that the above statement is true

❑ N/A or other (please explain) ______________________________________

____

2.6 If the box checked in Section 2.4 above is "Small hydro facilities", please certify that the facility does not involve any new impoundment or diversion of water with an average salinity of twenty (20) parts per thousand or less. – *per RES Regulations Section 3.31*

❑ ← check this box to certify that the above statement is true

❑ N/A or other (please explain) ______________________________________

____

2.7 If you checked one of the Biomass facilities boxes in Section 2.1 above, please respond to the following:

A. Please specify the fuel or fuels used or to be used in the Unit: _______________ _______Whole tree chips, sawdust and clean processed wood ________________

B. Please complete and attach Appendix F, Eligible Biomass Fuel Source Plan.
Appendix F completed and attached? X❑ Yes ❑ No ❑ N/A

2.8 Has the Generation Unit been certified as a Renewable Energy Resource for eligibility in another state's renewable portfolio standard?

❑ Yes x ❑ No If yes, please attach a copy of that state's certifying order.

Copy of State's certifying order attached? ❑ Yes ❑ No ❑ N/A

SECTION III: Commercial Operation Date

Please provide documentation to support all claims and responses to the following questions:

3.1 Date Generation Unit first entered Commercial Operation: 01 / ___ / 1988 at the site.

3.2 Is there an Existing Renewable Energy Resource located at the site of Generation Unit?

❑ X Yes
❑ No

3.3 If the date entered in response to question 3.1 is earlier than December 31, 1997 or if you checked "Yes" in response to question 3.2 above, please complete Appendix C.

Appendix C completed and attached? X ❑ Yes ❑ No ❑ N/A

3.4 Was all or any part of the Generation Unit used on or before December 31, 1997 to generate electricity at any other site?

❑ Yes
❑ X No

3.5 If you checked "Yes" to question 3.4 above, please specify the power production equipment used and the address where such power production equipment produced electricity (attach more detail if the space provided is not sufficient):

____

____

____

SECTION IV: Metering

4.1 Please indicate how the Generation Unit's electrical energy output is verified (check all that apply):

❑ X ISO-NE Market Settlement System
❑ Self-reported to the NEPOOL GIS Administrator
❑ Other (please specify below and see Appendix D: Eligibility for Aggregations):

____

Appendix D completed and attached? ❑ Yes ❑ No X❑ N/A

SECTION V: Location

5.1 Please check one of the following that apply to the Generation Unit:

- ❑ X Grid Connected Generation
- ❑ Off-Grid Generation (not connected to a utility transmission or distribution system)
- ❑ Customer Sited Generation (interconnected on the end-use customer side of the retail electricity meter in such a manner that it displaces all or part of the metered consumption of the end-use customer)

5.2 Generation Unit address: ____

_______________151 Smith River Road__________

________________Alexandria NH, 03222___________________

____

5.3 Please provide the Generation Unit's geographic location information:

A. Universal Transverse Mercator Coordinates: ________________________

B. Longitude/Latitude: _-71.744484__ /__43.567894__

5.4 The Generation Unit located: (please check the appropriate box)

- ❑ X In the NEPOOL control area
- ❑ In a control area adjacent to the NEPOOL control area
- ❑ In a control area other than NEPOOL which is not adjacent to the NEPOOL control area ← *If you checked this box, then the generator does not qualify for the RI RES – therefore, please do not complete/submit this form.*

5.5 If you checked "In a control area adjacent to the NEPOOL control area" in Section 5.4 above, please complete Appendix E.

Appendix E completed and attached? ❑ Yes ❑ No ❑ N/A

SECTION VI: Certification

6.1 Please attach documentation, using one of the applicable forms below, demonstrating the authority of the Authorized Representative indicated in Section 1.8 to certify and submit this Application.

Corporations

If the Owner or Operator is a corporation, the Authorized Representative shall provide **either**:

(a) Evidence of a board of directors vote granting authority to the Authorized Representative to execute the Renewable Energy Resources Eligibility Form, **or**

(b) A certification from the Corporate Clerk or Secretary of the Corporation that the Authorized Representative is authorized to execute the Renewable Energy Resources Eligibility Form or is otherwise authorized to legally bind the corporation in like matters.

Evidence of Board Vote provided? ❑ Yes ❑ No ❑ N/A

Corporate Certification provided? X❑ Yes ❑ No ❑ N/A

Individuals

If the Owner or Operator is an individual, that individual shall complete and attach APPENDIX A, or a similar form of certification from the Owner or Operator, duly notarized, that certifies that the Authorized Representative has authority to execute the Renewable Energy Resources Eligibility Form.

Appendix A completed and attached? ❑ Yes ❑ No X❑ N/A

Non-Corporate Entities

(Proprietorships, Partnerships, Cooperatives, etc.) If the Owner or Operator is not an individual or a corporation, it shall complete and attach APPENDIX B or execute a resolution indicating that the Authorized Representative named in Section 1.8 has authority to execute the Renewable Energy Resources Eligibility Form or to otherwise legally bind the non-corporate entity in like matters.

Appendix B completed and attached? ❑ Yes ❑ No X❑ N/A

6.2 Authorized Representative Certification and Signature:

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 immediately 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 possible fines and punishment. My signature below certifies all information submitted on this Renewable Energy Resources Eligibility Form. The Renewable Energy Resources Eligibility Form includes the Standard Application Form and all required Appendices and attachments. I acknowledge that the Generation Unit is obligated to and will notify the Commission promptly in the event of a change in a generator's eligibility status (including, without limitation, the status of the air permits) and that when and if, in the Commission's opinion, after due consideration, there is a material change in the characteristics of a Generation Unit or its fuel stream that could alter its eligibility, such Generation Unit must be re-certified in accordance with Section 9.0 of the RES Regulations. I further acknowledge that the Generation Unit is obligated to and will file such quarterly or other reports as required by the Regulations and the Commission in its certification order. I understand that the Generation Unit will be immediately de-certified if it fails to file such reports.

Signature of Authorized Representative:

SIGNATURE: [signature] DATE: 8/04/08

Vice President
(Title)

GIS Certification #:
————

APPENDIX C
(Required of all Applicants with Generation Units at the Site of Existing Renewable Energy Resources)

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISION

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM
Pursuant to the Renewable Energy Act
Section 39-26-1 et. seq. of the General Laws of Rhode Island

If the Generation Unit: (1) first entered into commercial operation before December 31, 1997; or (2) is located at the exact site of an Existing Renewable Energy Resource, please complete the following and attach documentation, as necessary to support all responses:

C.1 Is the Generating Unit seeking certification, either in whole or in part, as a New Renewable Energy Resource? X ❑ Yes ❑ No

C.2 If you answered "Yes" to question C.1, please complete the remainder of Appendix C. If you answered "No" and are seeking certification entirely as an Existing Renewable Energy Resource, you do NOT need to complete the remainder of Appendix C.

C.3 If an Existing Renewable Energy Resource is/was located at the site, has such Existing Renewable Energy Resource been retired and replaced with the new Generation Unit at the same site? ❑ Yes X❑ No

C.4 Is the Generation Unit a Repowered Generation Unit (as defined in Section 3.28 of the RES Regulations) which uses Eligible Renewable Energy Resources and which first entered commercial operation after December 31, 1997 at the site of an existing Generation Unit? ❑ Yes X❑ No

C.5 If you checked "Yes" to question C.4 above, please provide documentation to support that the entire output of the Repowered Generation Unit first entered commercial operation after December 31, 1997.

C.6 Is the Generation Unit a multi-fuel facility in which an Eligible Biomass Fuel is first co-fired with fossil fuels after December 31, 1997? ❑ Yes X ❑ No

C.7 If you checked "Yes" to question C.6 above, please provide documentation to support that the renewable energy fraction of the energy output first occurred after December 31, 1997.

C.8 Is the Generation Unit an Existing Renewable Energy Resource other than an Intermittent Resource (as defined in Section 3.9 and 3.14 of the RES Regulations)? X ❑ Yes ❑ No

C.9 If you checked "Yes" to question C.8 above, please attach evidence of completed capital investments after December 31, 1997 attributable to efficiency improvements or additions of capacity that are sufficient to, were intended to, and can be demonstrated to increase annual electricity output in excess of ten percent (10%). As specified in Section 3.22.v of the RES Regulations, the determination of incremental production shall not be based on any operational changes at such facility **not directly** associated with the efficiency improvements or additions of capacity.

C.10 Is the Generating Unit an Existing Renewable Energy Resource that is an Intermittent Resource? ❑ Yes ❑ No

C.11 If you checked "Yes" to question C.10 above, please attach evidence of completed capital investments after December 31, 1997 attributable to efficiency improvements or additions of capacity that are sufficient to, were intended to, and have demonstrated on a normalized basis to increase annual electricity output in excess of ten percent (10%). The determination of incremental production shall not be based on any operational changes at such facility **not directly** associated with the efficiency improvements or additions of capacity. In no event shall any production that would have existed during the Historical Generation Baseline period in the absence of the efficiency improvements or additions to capacity be considered incremental production. Please refer to Section 3.22.vi of the RES Regulations for further guidance.

C.12 If you checked "Yes" to C.10, provide the single proposed percentage of production to be deemed incremental, attributable to the efficiency improvements or additions of capacity placed in service after December 31, 1997. Please provide backup information sufficient for the Commission to make a determination of this incremental production percentage.

C.13 If you checked "no" to both C.3 and C.4 above, please complete the following:

a. Was the Existing Renewable Energy Resource located at the exact site at any time during calendar years 1995 through 1997? X❑ Yes ❑ No

b. If you checked "yes" in Subsection (a) above, please provide the Generation Unit Asset Identification Number and the average annual electrical production (MWhs) for the three calendar years 1995 through 1997, or for the first 36 months after the Commercial Operation Date if that date is after December 31, 1994, for each such Generation Unit.

c. Please attach a copy of the derivation of the average provided in (b) above, along with documentation support (such as ISO reports) for the information provided in Subsection (b) above. Data must be consistent with quantities used for ISO Market Settlement System.

GIS Certification #:

APPENDIX F
Eligible Biomass Fuel Source Plan
(Required of all Applicants Proposing to Use An Eligible Biomass Fuel)

STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISION
Part of Application for Certificate of Eligibility
RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM
Pursuant to the Renewable Energy Act
Section 39-26-1 et. sq. of the General Laws of Rhode Island

Note to Applicants: Please refer to the RES Certification Filing Methodology Guide posted on the Commission's web site (www.ripuc.org/utilityinfo/res.html) for information, templates and suggestions regarding the types and levels of detail appropriate for responses to specific application items requested below. Also, please see Section 6.9 of the RES Regulations for additional details on specific requirements.

The phrase "Eligible Biomass Fuel" (per RES Regulations Section 3.6) means fuel sources including brush, stumps, lumber ends and trimmings, wood pallets, bark, wood chips, shavings, slash, yard trimmings, site clearing waste, wood packaging, and other clean wood that is not mixed with other unsorted solid wastes[2]; agricultural waste, food and vegetative material; energy crops; landfill methane[3] or biogas[4], provided that such gas is collected and conveyed directly to the Generation Unit without use of facilities used as common carriers of natural gas; or neat bio-diesel and other neat liquid fuels that are derived from such fuel sources.

In determining if an Eligible Biomass Generation Unit shall be certified, the Commission will consider if the fuel source plan can reasonably be expected to ensure that only Eligible Biomass Fuels will be used, and in the case of co-firing ensure that only that proportion of generation attributable to an Eligible Biomass Fuel be eligible. Certification will not be granted to those Generation Units with fuel source plans the Commission deems inadequate for these purposes.

This Appendix must be attached to the front of Applicant's Fuel Source Plan required for Generating Units proposing to use an Eligible Biomass Fuel (per Section 6.9 of RES Regulations).

---

[2] Generation Units using wood sources other than those listed above may make application, as part of the required fuel source plan described in Section 6.9 of the RES Regulations, for the Commission to approve a particular wood source as "clean wood." The burden will be on the applicant to demonstrate that the wood source is at least as clean as those listed in the legislation. Wood sources containing resins, glues, laminates, paints, preservatives, or other treatments that would combust or off-gas, or mixed with any other material that would burn, melt, or create other residue aside from wood ash, will not be approved as clean wood.

[3] Landfill gas, which is an Eligible Biomass Fuel, means only that gas recovered from inside a landfill and resulting from the natural decomposition of waste, and that would otherwise be vented or flared as part of the landfill's normal operation if not used as a fuel source.

[4] Gas resulting from the anaerobic digestion of sewage or manure is considered to be a type of biogas, and therefore an Eligible Biomass Fuel that has been fully separated from the waste stream.

F.1 The attached Fuel Source Plan includes a detailed description of the type of Eligible Biomass Fuel to be used at the Generation Unit.

Detailed description attached? X❑ Yes ❑ No ❑ N/A

Comments: ______________________________

____

F.2 If the proposed fuel is "other clean wood," the Fuel Source Plan should include any further substantiation to demonstrate why the fuel source should be considered as clean as those clean wood sources listed in the legislation.

Further substantiation attached? ❑ Yes ❑ No X❑ N/A

Comments: ______________________________

____

F.3 In the case of co-firing with ineligible fuels, the Fuel Source Plan must include a description of (a) how such co-firing will occur; (b) how the relative amounts of Eligible Biomass Fuel and ineligible fuel will be measured; and (c) how the eligible portion of generation output will be calculated. Such calculations shall be based on the energy content of all of the proposed fuels used.

Description attached? ❑ Yes ❑ No X❑ N/A

Comments: ____________not co-firing

____

F.4 The Fuel Source Plan must provide a description of what measures will be taken to ensure that only the Eligible Biomass Fuel are used, examples of which may include: standard operating protocols or procedures that will be implemented at the Generation Unit, contracts with fuel suppliers, testing or sampling regimes.

Description provided? X❑ Yes ❑ No ❑ N/A

Comments: ______________________________

____

F.5 Please include in the Fuel Source Plan an acknowledgement that the fuels stored at or brought to the Generation Unit will only be either Eligible Biomass Fuels or fossil fuels used for co-firing and that Biomass Fuels not deemed eligible will not be allowed at the premises of the certified Generation Unit. And please check the following box to certify that this statement is true.

X ❑ ← check this box to certify that the above statement is true

❑ N/A or other (please explain) ______________________________

____

F.6 If the proposed fuel includes recycled wood waste, please submit documentation that such fuel meets the definition of Eligible Biomass Fuel and also meets material separation, storage, or handling standards acceptable to the Commission and furthermore consistent with the RES Regulations.

Documentation attached? ❑ Yes ❑ No X❑ N/A

Comments: ____

____

F.7 Please certify that you will file all reports and other information necessary to enable the Commission to verify the on-going eligibility of the renewable energy generators pursuant to Section 6.3 of the RES Regulations.

X❑ ← check this box to certify that the above statement is true

❑ N/A or other (please explain) ______________________________

____

F.8 Please attach a copy of the Generation Unit's Valid Air Permit or equivalent authorization.

Valid Air Permit or equivalent attached? X❑ Yes ❑ No ❑ N/A

Comments: _______The Air Permit is Temporary, because the New Hampshire considers this plant new because it was shut down for so long. After three months of operation a Final Air Permit will be provided.

F.9 Effective date of Valid Air Permit or equivalent authorization:

__02_ ___/ 04 / 2008

F.10 State or jurisdiction issuing Valid Air Permit or equivalent authorization: _______________New Hampshire_______________________

Indeck Alexandria Energy Center RES Application
Attachment for Appendix C

C.9

The Indeck Alexandria Energy Center ("Alexandria") 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. Beginning in 2008, Alexandria began a re-commissioning, with Indeck Energy-Alexandria, LLC investing in efficiency improvements to the facility as a whole. During the re-commissioning many improvements are being made to the facility and the boiler with the intention of increasing the efficiency, performance and output of the facility. Such improvements to the boiler are the addition of over-fire air nozzles to improve combustion, as well as adding a super-heater surface area to the boiler to increase steam temperature to increase efficiency. The low pressure end of the turbine casing has been reshaped to improve steam flow to the condenser, again increasing the efficiency and performance.

In addition to improvements to the boiler, other improvements have been made to the Alexandria 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 redesigning the water balance of the facility to lower water consumption, generate less waste water and to 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.

Alexandria has not been re-fired yet so at this point we can not provide proof that the aforementioned improvements have resulted in a 10% percent annual output increase, however, it is confidently expected that they will. Just the addition of the super-heater surface area alone is capable of meeting the 10% percent annual output increase requirement; therefore, the super-heater coupled with the other efficiency improvements will increase the output of the facility in excess of 10% annually over the historic generation. Proof can be provided once we have generation data from the re-commissioning.

C 13.

b. Indeck Alexandria Energy Center Generation Unit Asset Identification Number 1631

The average annual electrical production (MWhs) for the three calendar years 1995 through 1997: 0MWhs (The unit has been shut down since November 1994)

c. Alexandria was first commercially operational in January 1988. 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. The Settlement Agreement prohibiting Alexandria from operating expired on Nov 12, 2007. In 2008, Indeck Energy-Alexandria, LLC began re-commissioning the facility.

Documents to support the Historic Generation Rate are: 1) Letter from PSNH to confirm the unit has been shut down 2) Letter from NH DES that the unit has been shut down 3) the attached Air Permit also confirms the plant was shut down 4) The historic generation from the plant which ends in October 1994.

Indeck Alexandria Energy Center RES Application
Attachment for Appendix F

F.1 The type of Eligible Biomass Fuel to be used at the Generation Unit:

Alexandria will use as a fuel source Eligible Biomass Fuels of whole tree chips, sawdust and clean processed wood fuels. The facility will be using 100% virgin wood fiber; this is wood fiber that comes directly from the forest. Most of the wood fuel will be whole tree chips that are chipped at the location where the trees are cut down. Brush and saw mill residue (sawdust, cutoffs, log mill slabs and board ends), also virgin wood as it is not manufactured into anything, is also a source of fuel for the facility. Saw mill residue is produced before the logs are made into lumber. The brush and saw mill residue is ground or processed into wood chips instead of being chipped. 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 and it is illegal to combust construction and demolition derived wood fuel.

F.4 The Fuel Source Plan

Alexandria is a counterparty to fuel supply arrangements with suppliers for natural wood fiber. The wood fiber that is contracted to be delivered adheres to the quality wood fuel standards as stated above, as well as qualifying as Open-Loop Biomass as defined in the Internal Revenue Code Section 45. Alexandria has a scale and recording procedure for incoming wood fuel deliveries. The recording procedures include, who is bringing in the fuel, how much it weighs and the type of wood and the operation that produced the wood. 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 brought and used at the facility. There will be a constant thirty (30) day supply of wood chips at the facility at all times. The wood chips will be ground two weeks before they are burned to keep constant moisture throughout the fuel supply. Daily moisture and BTU analysis is done on the wood chips.

INDECK ENERGY-ALEXANDRIA, L.L.C. • 600 North Buffalo Grove Road • Suite 300 • Buffalo Grove, Illinois 60089
847/520-3212 • Fax: 847/520-9883

INDECK®

Certification of Authorized Representative

July 2, 2008
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
Attn: Renewable Energy Resources Eligibility

I, Michael D. Ferguson, Vice President of Asset Management for Indeck Energy-Alexandria, LLC, certify that Patricia Stanton as Vice President, Clean Energy Markets is the Authorized Representative for the Alexandria Energy Center facility named in Section 1.8 of the Rhode Island Renewable Energy Resources Eligibility Form and is authorized to execute The Standard Application Form.

Signature: Michael D. Ferguson
Indeck Energy-Alexandria, LLC.

Date: July 2, 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

Public Service of New Hampshire

PSNH Energy Park
780 North Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P.O. Box 330
Manchester, NH 03105-0330
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The Northeast Utilities System

July 21, 2008

Indeck Energy-Alexandria, LLC
600 N Buffalo Grove Road
Suite 300
Buffalo Grove, IL 03105
Attn: Mike Ferguson, VP of Asset Management

Subject: Alexandria Power (SESD #320)
Shut Down and Start Up Dates

Dear Mr. Ferguson:

This letter is sent with the intentions to clarify the shut down date and subsequent start up date of the Indeck Alexandria Energy Center ("Facility") located in Alexandria New Hampshire.

During 4th Quarter 1994, Alexandria ceased operation and PSNH disconnected the Facility from its 3114X circuit.

On February 23, 2008 PSNH reconnected the Facility to the 3114X circuit to provide station service load only as the interconnection process for delivery of energy from the Facility to the ISO-NE power grid continues.

During this aforementioned period of disconnection, the Facility did not generate any electricity. If there are any further questions concerning the operation of this Facility, please do not hesitate to contact me.

Sincerely,

Carl N. Vogel, III
Manager,
Supplemental Energy Sources Department

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	*Precautions to Prevent, Abate, and Control Fugitive Dust* Any person engaged in any activity, except those listed in Env-A 1002.02(b), that emits fugitive dust within the state shall take precautions throughout the duration of the activity in order to prevent, abate, and control the emission of fugitive dust, including, but not limited to wetting, covering, shielding, or vacuuming.	Facility Wide	Env-A 1002.04
2	*24-hour and Annual Ambient Air Limit – Boiler & Cooling Tower* 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	*Revisions of the List of RTAPs* In accordance with RSA 125-I:5 IV, if the Division revises the list of RTAPs or their respective AALs or classifications under RSA 125-I:4, II and III, and as a result of such revision the Owner or Operator is required to obtain or modify the permit under the provisions of RSA 125-I or RSA 125-C, the Owner or Operator shall have 90 days following publication of notice of such final revision in the New Hampshire Rulemaking Register to file a complete application for such permit or permit modification.	Facility Wide	RSA 125-I:5 IV
4	*Methods of Demonstrating Compliance* 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	*Compliance Demonstration* 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	*Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR) Program Avoidance*[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	*Prevention of Significant Deterioration (PSD) Avoidance* 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	*Maximum Gross Heat Input Rate* 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	*Allowable Fuels for the Boiler* 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 Volumetric 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	<u>*Annual Emissions Report*</u> 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	<u>*NO_x Emission Statements Reporting Requirements*</u> 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	<u>*Reporting of Monthly 12-Month Rolling Total Emissions*</u> 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	*NSPS Initial Startup Notification* 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	*Reporting of NSPS Performance Test Results* 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	*NSPS Annual Capacity Factor Reporting* Submit the annual capacity factor over the previous 12 months for each fuel fired in the Boiler in each semi-annual report to DES and EPA.	Semi-annually, postmarked by the 30th day following the end of the 6 month reporting period	EU1	40 CFR 60 Subpart Db Section 60.49b(q)(1)
7	*NSPS Very Low Sulfur Oil Recordkeeping and Reporting Requirement* The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period.	Semi-annually, postmarked by the 30th day following the end of the 6 month reporting period	EU1	40 CFR 60 Subpart Db Section 60.49b(r)

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.