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

INDECK ®

June 19, 2013

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
Lmassaro@puc.state.ri.us

Dear Clerk Massaro:

Attached please find a Renewable Energy Resources Eligibility Form for the biomass generation unit located in Alexandria, New Hampshire (the "Facility") owned and operated by Indeck Energy-Alexandria, LLC ("Indeck"). In addition to this electronic filing, an original and three paper copies are being filed via U.S. Mail at the above address.

Please note that on August 5, 2008, Indeck filed a Renewable Energy Resources Eligibility Form for certification of the Facility as a Rhode Island New Renewable Energy Resource. The Commission assigned Docket No. 3979 to that application. At the time Docket No. 3979 was opened, Indeck's redevelopment of the Facility was not yet complete, and the Facility remained non-operational. The Commission placed the application on hold pending submission of post-commissioning data. Because of the passage of time, Indeck has opted to file a new application for certification of its redeveloped Facility rather than pursue the application filed in Docket No. 3979. Therefore, with this filing, Indeck requests the withdrawal of its earlier application and asks that the Commission act on the application contained in this filing in a new docket.

Indeck's redevelopment efforts have proven successful. The Facility began producing energy in November 2008. By this application, Indeck requests certification of 100% of its Facility output as a Rhode Island New Renewable Energy Resource.

Respectfully submitted,

Michael Ferguson

Michael Ferguson
Vice President, Operations & Management
p: (847)-520-3212 | Email: MFerguson@indeck-energy.com

Encl.
cc: Attached Service List

Application for Certification as Eligible Renewable Energy Resource
Service List updated 6/5/13

Name/Address	E-mail Service List
Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	res@puc.state.ri.us
Scott Albert, Principal & Northeast Region Manager GDS Associates, Inc. 1155 Elm Street, Suite 702 Manchester, NH 03101	
James Webb, GIS Administrator APX - Our Knowledge is Power	GIS@apx.com
Thomas R. Teehan, Esq. National Grid	Thomas.teehan@us.ngrid.com Joanne.scanlon@us.ngrid.com
Jon Hagopian, Division of Public Utilities & Carriers	jhagopian@ripuc.state.ri.us
Dennis Duffy, VP of Regulatory Affairs Cape Wind Associates LLC	dduffy@emienergy.com
M. Haggerty, Ridgewood Power	mhaggerty@ridgewoodpower.com dgulino@ridgewoodpower.com
Christopher T. Burnett, President SpinBlade Energy LLC	cburnett@spinbladeenergy.com
Hallie Flint Gilman, Associate General Counsel First Wind	regulatory@firstwind.com
Gerald M. Eaton, Public Service Co. of New Hampshire	eatongm@nu.com
Alan M. Shoer, Esq., Adler Pollock & Sheehan, P.C.	Ashoer@apslaw.com
Karina Lutz, Director of Development and Advocacy People's Power & Light LLC	karina@ripower.org estephens@noreastgroup.com
Stephan Wollenburg, Energy Consumers Alliance of NE	stephan@massenergy.org
Patricia D. Stanton, Conservation Services Group	Pat.Stanton@csgrp.com
George Wood,Oak Point Energy Associates	george4wood@verizon.net
John Morrow, Amerex Renewables	jmorrow@amerexenergy.com
Stephen Hickey, Essex Hydro	sjh@essexhydro.com
Gary Gump – Portsmouth EDC Sustainable Energy subcommittee	Ggump1@verizon.net
Kimberley A. Barry, PPL Energy Plus LLC Owen Klicker, PPL EnergyPlus, LLC	kabarry@pplweb.com baveety@pplweb.com ojklicker@pplweb.com
Supria Ranade, Evolution Markets	sranade@evomarkets.com

Kate Bogart, Mass Energy/People's Power & Light	Kate@massenergy.org
Joseph Seymour, Renewable Energy Markets Association	JSEYMOUR@ttcorp.com
John R Tigue III, Mgr., Electric Supply, NYSEG/RG&E	jrtigue@nyseg.com
Robert C. Grace - Sustainable Energy Advantage	bgrace@seadvantage.com

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

GIS Certification #: ____________________

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM
INDECK ENERGY-ALEXANDRIA, LLC
The Standard Application Form
Required of all Applicants for Certification of Eligibility of Renewable Energy Resource
(Version 8 – December 5, 2012)

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
Attn: Luly E. Massaro, Commission Clerk
89 Jefferson Blvd
Warwick, RI 02888

In addition to the paper copies, electronic/email submittals are required under Commission regulations. Such electronic submittals should be sent to res@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 Energy-Alexandria, LLC: GIS Plant Unit: PEMIGWAS-INDECK ALEXANDRIA. Also see Attachment 2.1.

1.2 Type of Certification being requested (check one):

☑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

☑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

☑ APPENDIX F: Fuel Source Plan for Eligible Biomass Fuels

1.4 Primary Contact Person name and title: Mike Ferguson, Vice President Operations & Asset Management

1.5 Primary Contact Person address and contact information:
Address: Indeck Energy Services
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL. 60089
Phone: (847) 520-3212 Fax: (847) 520-9883
Email: MFerguson@indeck-energy.com

1.6 Backup Contact Person name and title: William Garth, Director of Finance

1.7 Backup Contact Person address and contact information:
Address: Indeck Energy Services
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL. 60089
Phone: (847) 520-3212 Fax: (847) 520-9883
Email: BGarth @indeck-energy.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):

Mike Ferguson, Vice President, Operations & Asset Management

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

1.9 Authorized Representative address and contact information:
Address: Indeck Energy Services
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL. 60089
Phone: (847) 520-3212 Fax: (847) 520-9883
Email: MFerguson@indeck-energy.com

1.10 Owner name and title: Indeck Energy-Alexandria, LLC
Mike Ferguson, Vice President, Operations & 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) 520-3212 Fax: (847) 520-9883
Email: MFerguson@indeck-energy.com

1.12 Owner business organization type (check one):
❑ Individual
❑ Partnership
❑ Corporation
☑ Other: Limited Liability Company

1.13 Operator name and title: Indeck Energy-Alexandria, LLC
Bryan Coutu, 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: BCoutu@indeck-energy.com

1.15 Operator business organization type (check one):
❑ Individual
❑ Partnership
❑ Corporation
☑ Other: Limited Liability Company

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): See Attachment 2.1

2.2 Generation Unit Nameplate Capacity: 16 MW net

2.3 Maximum Demonstrated Capacity: 15.6 MW net

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
- ☑ 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 3.32*

☐ ← 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 3.32*

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

☑ N/A or other (please explain) ______________________________

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2.7 If you checked one of the Biomass facilities boxes in Section 2.4 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. Also see Attachment F-1.

B. Please complete and attach Appendix F, Eligible Biomass Fuel Source Plan.

Appendix F completed and attached? ☑ 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 ❑ No If yes, please attach a copy of that state's certifying order.

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

See Attachment 2.8

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.

If the commercial operation date is after December 31, 1997, please provide independent verification, such as the utility log or metering data, showing that the meter first spun after December 31, 1997. This is needed in order to verify that the facility qualifies as a New Renewable Energy Resource.

Documentation attached? ❑ Yes ❑ No ☑ N/A

See Attachment 3.1: The Facility ceased operation in November 1994. After a capital investment from the new owner the Facility re-entered operation in November 2008.

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

☑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? ☑ 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
☑ 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):
N/A.

SECTION IV: Metering

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

SECTION V: Location

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

☑ 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: 276000 E and 4826500 N

B. Longitude/Latitude: -71.744484 / 43.567894

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

☑ 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? ☐ 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 ☑ 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 ☐ 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:	DATE:
Mike Ferguson	6/24/13

Mike Ferguson
Vice President, Operations & Asset Management

LIST OF ATTACHMENTS TO RHODE ISLAND RES STANDARD APPLICATION FORM OF INDECK ENERGY-ALEXANDRIA, LLC

1. Attachment 2.1: Generation Asset Identification
2. Attachment 2.8: RPS Certification (Maine, Connecticut and New Hampshire)
3. Attachment 3.1: Commercial Operation Date
4. Appendix B
5. Appendix C with Attachment C, and Exhibits 1 through 6
6. Appendix F with Attachment F (including F-1 Fuel Source Plan, F-4 Eligible Fuel, and F-8 Air permit)

Attachment 2.8

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2008-336

November 18, 2008

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

ORDER GRANTING NEW RENEWABLE RESOURCE CERTIFICATION

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

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

II. BACKGROUND

A. New Renewable Resource Portfolio Requirement

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. Petition for Certification

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

III. DECISION

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

BY ORDER OF THE DIRECTOR OF TECHNICAL ANALYSIS

Faith Huntington

STATE OF CONNECTICUT

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

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

January 27, 2010

By the following Commissioners:

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

DECISION

I. INTRODUCTION

A. SUMMARY

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

B. Background of the Proceeding

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

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

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

C. Conduct of the Proceeding

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

D. Participants in the Proceeding

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

II. DEPARTMENT ANALYSIS

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

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

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

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

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

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

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

III. FINDINGS OF FACT

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

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

3. Alexandria began operation on January 31, 2009.

4. Alexandria has a nameplate capacity of 16.5 MW.

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

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

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

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

IV. CONCLUSION

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

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

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

V. ORDERS

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

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

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

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

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

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

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

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

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

This Decision is adopted by the following Commissioners:

John W. Betkoski, III

Kevin M. DelGobbo

Anthony J. Palermino

CERTIFICATE OF SERVICE

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

Kimberley J. Santopietro
Executive Secretary
Department of Public Utility Control

1/27/10
Date

THE STATE OF NEW HAMPSHIRE

CHAIRMAN
Thomas B. Getz

COMMISSIONERS
Clifton C. Below
Amy L. Ignatius

EXECUTIVE DIRECTOR
AND SECRETARY
Debra A. Howland

PUBLIC UTILITIES COMMISSION
21 S. Fruit Street, Suite 10
Concord, N.H. 03301-2429

Tel. (603) 271-2431

FAX (603) 271-3878

TDD Access: Relay NH
1-800-735-2964

Website:
www.puc.nh.gov

April 14, 2010

Stephanie Lovejoy Hamilton
Conservation Services Group
40 Washington Street
Westborough, MA 01581

Re: DE 09-008, Conservation Services Group
on behalf of Indeck Energy-Alexandria, LLC
Certification Application for Class I Eligibility Pursuant to RSA 362-F

Dear Ms. Hamilton:

On January 26, 2009, Conservation Services Group submitted an application on behalf of Indeck Energy-Alexandria, LLC requesting conditional certification for the Indeck Alexandria biomass facility (Alexandria facility) as a Class I facility pursuant to RSA 362-F, New Hampshire's Renewable Portfolio Standard law. On July 17, 2009, the Commission issued a secretarial letter granting conditional approval of the Alexandria facility and stated that it would fully certify the facility upon receipt of verification of compliance with emissions standards from the Department of Environmental Services (DES). On April 6, 2010, DES notified the Commission that test results indicate that the Alexandria facility meets the emission requirements. DES also recommended that the Commission fully certify the facility as a renewable energy source eligible to produce renewable energy certificates.

The Commission has reviewed the April 6, 2010 letter from DES verifying compliance with the emissions standards required by RSA 362-F and now designates the Alexandria facility as eligible to produce Class I renewable energy certificates effective April 6, 2010.

Attached please find a copy of the notice of this certification provided to the GIS administrator. The New Hampshire Renewable Portfolio Standard certification code for the Alexandria facility is NH-I-10-033.

Sincerely,

Debra A. Howland

Debra A. Howland
Executive Director

CHAIRMAN
Thomas B. Getz

COMMISSIONERS
Clifton C. Below
Amy L. Ignatius

EXECUTIVE DIRECTOR
AND SECRETARY
Debra A. Howland

THE STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION
21 S. Fruit Street, Suite 10
Concord, N.H. 03301-2429

Tel. (603) 271-2431

FAX (603) 271-3878

TDD Access: Relay NH
1-800-735-2964

Website:
www.puc.nh.gov

April 14, 2010

James Webb
Registry Administrator
APX Environmental Markets
224 Airport Parkway, Suite 600
San Jose, CA 95110

Re: DE 09-008, Indeck Alexandria Biomass Facility
Certification as a New Hampshire RPS Class I Facility
Certification Code NH-I-10-033

Dear Mr. Webb:

Please be advised that, pursuant to NH RSA 362-F, the New Hampshire Public Utilities Commission has certified the Indeck Alexandria biomass facility (Alexandria facility) as a Class I renewable energy source effective April 6, 2010. Accordingly, the Alexandria facility is eligible to be issued New Hampshire Class I renewable energy certificates.

The Alexandria facility is a biomass facility located at 151 Smith River Road, Alexandria, New Hampshire and has a gross nameplate capacity of 16.5 megawatts. The facility's ISO-New England asset identification number is MSS 14211. The New Hampshire Renewable Portfolio Standard certification code is NH-I-10-033.

Sincerely,

Debra A. Howland

Debra A. Howland
Executive Director

cc: Stephanie Lovejoy Hamilton
Conservation Services Group

Attachment 3.1

See Attachment C; Supplemental Response to Appendix C.9 for discussion of Initial Commercial Operations Date, 13 Year Cessation of Operation, and 2008 Facility Redevelopment

GIS Certification #:
————

APPENDIX B
(Required When Owner or Operator is a Non-Corporate Entity Other Than An Individual)

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

Indeck Energy-Alexandria, LLC

RESOLUTION OF AUTHORIZATION

Resolved: that Mike Ferguson, Vice President , Operations & Asset Management, named in Section 1.8 of the Renewable Energy Resources Eligibility Form as Authorized Representative, is authorized to execute the Application on the behalf of Indeck Energy-Alexandria, LLC, the Owner or Operator of the Generation Unit named in section 1.1 of the Application.

SIGNATURE: Michael Ferguson
VP, Operations & Asset Management

DATE: 6/24/13

State: IL
County: Lake

(TO BE COMPLETED BY NOTARY) I, Constance S. Lada as a notary public, certify that I witnessed the signature of the above named Mike Ferguson, and that said person stated that he/she is authorized to execute this resolution, and the individual verified his/her identity to me, on this date: 6/24/13.

SIGNATURE: Constance S. Lada

DATE: 6/24/13

My commission expires on: 11/23/16

NOTARY SEAL:

OFFICIAL SEAL
CONSTANCE S LADA
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:11/23/16

GIS Certification #:
____

APPENDIX C
(Revised 6/11/10)
(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

Indeck Energy-Alexandria, LLC

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? ☑ 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 ☑ No

C.4 Is the Generation Unit a Repowered Generation Unit (as defined in Section 3.29 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 ☑ 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 ☑ 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 Sections 3.10 and 3.15 of the RES Regulations)? ☑ 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 3.23.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. **See Attachment C and Exhibits thereto.**
Please 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 make this calculation by comparing actual electrical output over the three calendar years 1995-1997 (the "Historical Generation Baseline") with the actual output following the improvements. The incremental production above the Historical Generation Baseline will be considered "New" generation for the purposes of RES. Please give the percentage of the facility's total output that qualifies as such to be considered "New" generation. **100 %**

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 3.23.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. The incremental production above the Historical Generation Baseline will be considered "New" generation for the purposes of RES. Please make this calculation by comparing actual monthly electrical output over the three calendar years 1995-1997 (the "Historical Generation Baseline") with the actual output following the improvements on a normalized basis. Please provide back-up information sufficient for the Commission to make a determination of this incremental production percentage.

For example, for small hydro facilities, please use historical river flow data to create a monthly normalized comparison (e.g. average MWh produced per cubic foot/second of river flow for each month) between actual output values post-improvements with the Historical Generation Baseline. For solar and wind facilities, please use historical solar irradiation, wind flow, or other applicable data to normalize the facility's current production against the Historical Generation Baseline.

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? ☑ 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. **See attachment 2.1 for asset identification number. Average annual electrical production for the three calendar years 1995 through 1997 was zero MWhs.**

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.

See Attachment C and Exhibits thereto.

<u>Supplemental Response to Appendix C.9</u>:

A biomass facility first became operational on the site of the Indeck Energy-Alexandria, LLC generating unit (the "Facility") in January 1988 with a nameplate capacity of 16 MWs net.. That facility completely ceased operations in November 1994, at which time the facility was closed, decommissioned, and disconnected from the electrical grid. Indeck acquired the Facility site and equipment from the previous owner on December 22, 1997. The facility remained disconnected from the electrical grid until February 2008, when Public Service Company of New Hampshire began supplying station service. Exhibit 1. The facility, however, remained incapable of operating. Indeck's efforts at redevelopment and work on interconnecting the Facility to the grid for the purposes of supplying energy continued through 2008.

In late 2007, when Indeck first began the process of redevelopment, the original facility was not legally or mechanically capable of operation. Having been shuttered for 13 years, the original facility had no connection to the grid, and at that time no claimed capability with NEPOOL or ISO New England, and no air permit. Major and minor components alike required rebuilding or replacement and permitting requirements needed to be met before operations could commence. These development activities are described in Section 3 below. New and different air emission controls were required and existing air emissions controls needed repair and upgrading to meet modern emission standards. Indeck undertook a substantial capital investment, totaling over $7,000,000, to commence generation operations at the site. Consequently, approximately 85% or more of the total cost of the current Facility is now attributable to investments made since Indeck began the re-development process in 2007. See Exhibit 2.

2. <u>New Renewable Energy Resources Pursuant to RI RES Rule 3.23</u>

RI RES Rule 3.23 defines six types of "New Renewable Energy Resources." Generally, these six types include the entire output of a new facility at a new site (Rule 3.23(i)), the entire output of a new Generation Unit[1] at an existing site (Rule 3.23(ii)), the entire output of a Repowered Generation Unit[2] at the site of an "existing Generation Unit" (Rule 3.23(iii)), the output generated using Eligible Biomass fuels when first co-fired with fossil fuels after December 31, 1997 (Rule 3.23(iv)), and incremental production over the production that occurred during the "baseline period" of 1995 through 1997 following capital investments in Existing Renewable Energy Resources attributable to efficiency improvements or additions of capacity (Rule 3.23(v) and (vi).

[1] This provision requires the retirement and replacement of the entire facility. <u>See also</u> RI RES Rule 3.13.

[2] For biomass units, a Repowered Generation Unit requires the retirement and replacement of the boiler with a new one resulting in either a material increase in efficiency or a material decrease in air emissions and a showing that 80% of the facility's resulting tax basis is attributable to the expenditures made after December 31, 1997. <u>See</u> RI Res Rules 3.27 and 3.29. At 85% of the Facility's resulting tax basis, Indeck's investment actually exceeds the 80% investment required to qualify the Facility's entire output as a "Repowered Generation Unit." See Exhibit 2.

In this application, as it did in Docket No. 3979, Indeck applied for certification of the Facility under RI RES Rule 3.23(v). This rule requires certification as a "New Renewable Energy Resource" of the "incremental output in any Compliance Year over the Historical Generation Baseline" of any "Existing Renewable Energy Resource . . . using Eligible Renewable Energy Resources" . . . certified by the Commission . . . to have demonstrably completed capital investments after December 31, 1997 attributable to the 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%)." RI RES Rule 3.23(v).

3. <u>The Facility Meets the Rule 3.23(v) Requirements</u>

Indeck's Facility meets the requirements of Rule 3.23(v) for the following reasons:

Indeck's capital investment of more than $7,000,000 made in 2007 and 2008 was intended to and did add approximately 15.2 to 15.6 MW (net) of capacity where none had existed since January 1, 1995. Exhibit 3. Indeck's capital investment was necessary to create this capacity at the site. The capacity associated with the Facility first commissioned in January 1988, was no longer recognized by ISO-NE as of January 1, 1995. See Exhibit 4 (CELT Report Excerpts 1995, 1997, 1998. The facility was not a capacity resource in 1996, however that CELT report could not be located). ISO-NE did not recognize a capacity resource with a capacity rating at the site again until the currently operating Facility received a capacity rating from ISO-NE in 2009. Exhibit 4. Thus, for the three year period of the historical baseline (and for approximately another ten years) there was no capacity at the site.

Furthermore, as noted above and described in detail below, nearly every component of the original Facility, whether major or minor, required some type of rebuilding or replacement. The current Facility also required permitting, most significantly the acquisition of an air permit as a new source of air emissions. Without Indeck's investment there would be no capacity at the site, and the current Facility would not exist to produce base load renewable energy.

Indeck made capital investments in major and minor components of the facility. The most significant are listed below, and the complete list of projects completed in 2007 and 2008 and their costs are listed in Exhibit 5.

- <u>Super-heater tube surface added</u>

  Work included the design/specifications, purchase and installation of added superheater surface to increase the boiler capability up to the turbine nameplate design of 850 deg F. This addition increased the capacity and efficiency of overall boiler operations.

- Boiler tubes retired and replaced

  This work summarizes the repair and refurbishment of all boiler steel, pressure parts, water walls, generator section and refractory.

- Air heater tubes retired and replaced

  The original boiler design included a tubular air heater. Initial refurbishment dealt with the repair of the housing and full scale leak test. Subsequent work involved complete tube replacement of the hot side section of the air heater.

- Stoker grates retired and replaced; system aligned

  The Zurn Travelgrate was initially inspected to determine operability. Initial work included replacement of numerous tiles and bars. The system was then aligned and prepared for operation. Subsequent work identified more suspect tiles, and additional problem bars and sprockets were identified and replaced.

- Boiler make-up water reverse osmosis unit added

  A new Reverse Osmosis System, a significant upgrade compared to the previous demineralized water system, was purchased and employed in the overall water treatment system for the facility. Indeck Alexandria is a zero discharge plant with challenging water treatment requirements.

- Boiler modified to add over-fire air injection

  Modifications of the overfire air system (OFA) were undertaken and included design, detail, fabrication and installation of the modifications needed to achieve the required NOx and CO levels. Effort included additional ducting, equipment refurbishment, new boiler penetrations and damper work.

- Low-pressure end of the turbine case reshaped to improve steam flow

  The low-pressure end of the steam turbine required re-shaping in order to improve steam flow and upgrade the steam turbine capability to its original performance specifications.

- Wood distribution damper added above surge bin to improve fuel distribution across feed screws

  A new wood distribution damper, an upgrade from its original design, was added at the surge bin. Device improved fuel distribution in the surge bin, thus aiding control wood screw material feed into the boiler for better capacity and efficiency during plant operation.

- Variable speed controllers added to improve surge bin level control and improve fuel distribution

  Plant operations are dependent on operational ability to successfully manage even fuel delivery from the surge bin to the stoker grate for increased availability, capacity and efficiency during plant operation. Variable speed controllers were added to improve this operational constraint.

- Boiler pumps rebuilt

  The boiler feedwater pumps and drives were completely removed and reconditioned. The work included electrical testing, bake and dip, new bearings and re-installation.

- Various pumps and motors in combustion system reconditioned

  In a similar fashion to the main feedwater pumps, all miscellaneous pumps were removed, reconditioned off-site and re-installed.

- Voltage regulation was updated by removing the analog voltage regulation system and replacing it with an automatic voltage regulator.

- ESP fields reconstructed and one transformer replaced

  The electrostatic precipitator had sustained damage from high temperature. Numerous electrodes were removed and replaced. Warped collection plates were also replaced.

- Static var compensator added

  Because the redeveloped Facility was new to the grid, its operation was subject to grid limitations that had developed since the old facility was disconnected and decommissioned, and which became apparent as a result of system impact studies. Grid limitations were such that plant output had to be constrained. A static var compensator was required to be added to the switchyard to address this limitation and enable the plant to maximize it's the redeveloped Facility's electrical output.

All of the investments made at the Facility site since 2007 relate directly to a 100% addition of approximately 15.2 to 15.6 MWs (net) of renewable generation capacity as compared to base period of 1995-1997. Yearly gross output during the base period of 1995-1997, was zero. In fact, there was zero production through October 2008. Exhibit 6 lists the yearly net output of the Facility since Indeck generated its first MWh of electricity in November 2008. Indeck's addition of 15.2 to 15.6 MW (net) of renewable capacity resulted in increased annual electricity output of more than 10% compared to the electrical output over the Historical Generation Baseline of 0 MWhs.

The incremental production sought in this application does not result from changes in the manner of operating the Facility (e.g., baseload operations compared to peaking operations) or decreases in Facility output or availability due to reduced maintenance activities or lack of fuel supply during operation. Instead, as noted above the incremental production sought in the application is a direct result of Indeck's significant capital investment in the Facility, site and equipment shuttered by the previous owner

Indeck is not the original owner of the facility site. The previous owner, Bristol Energy, was a successor to the original owner Alexandria Power. In November 1994, Bristol Energy closed the Facility and Public Service Company of New Hampshire disconnected it from the electrical grid. See Exhibit 1. At that time it ceased to exist as a viable physically operable plant. For approximately the next 13 years the facility site produced no electrical output and, as of January 1, 1995 was not recognized by ISO-NE as capacity. During that time, other than an individual employed to provide site security, there were no employees of the power company.

Also, since 1994, the facility produced no air emissions and was not included in the state's emissions inventory since 1994. See the Temporary Permit issued by the New Hampshire Department of Environmental Services (NHDES) at page 3 included in this application as Exhibit F-8.

The facility site and equipment was acquired by Indeck from the previous owner on December 22, 1997. Thus for all but 8 days of the historic baseline period, during which time it remained shuttered, the facility site and equipment was not owned by Indeck. Upon acquiring ownership, Indeck held the site in its shuttered condition pending initiation of redevelopment activities.

Indeck commenced active power plant redevelopment at the site in 2007. This involved the capital investment and equipment development activities noted above. It also involved the acquisition of an entirely new air permit from NHDES. The redeveloped facility's Title V operating permit first was issued to Indeck on September 28, 2000. (The Title V permit expired in 2005 and a new Temporary Permit was issued and is attached as Exhibit F-8). Given the magnitude of work undertaken at the site and on the facility, NHDES "[considered] this facility as new construction". Exhibit F-8 at page 3. As a direct result of this new construction the Facility particulate matter and NOx air emissions decreased by approximately 67% on a tons per year basis compared to the original Facility operating limits. Particulate matter emissions went from 0.03 lbs. /mmBtu to 0.01 lbs. /mmBtu and NOx emissions went from 0.23 lbs. /mmBtu to a rate below 0.075 lbs. /mmBtu.

The magnitude of redevelopment undertaken at the site has been recognized by other states having a class I RPS that is based on "new unit" status. Since Indeck's investment and capital additions to the Facility resulting in its re-commissioning, the Facility has been certified as a class I (new) facility under the New Hampshire RPS for its entire output and under the Maine RPS for its entire output. See Exhibit 2.8. (The Facility is also class I Connecticut RPS certified, however, that RPS does not require its class I units to be "new").

4. <u>Summary</u>

During the period December 1994 through October 2008, which includes the historic baseline period of 1995 through 1997, no power generation occurred at the site and the site was not the location of an ISO-New England claimed capability rating. Beginning in 2007, Indeck made capital investments in the Facility that equal approximately 85% of the Facility's cost basis and which are attributable to an addition of capacity. Due to Indeck's capital investments, the Facility now has a capacity of approximately 15.2 to 15.6 MW (net). See Exhibits 3 and 6. In its first two full years of operation (2010 and 2011), annual net output averaged 91,921.58 MWhs. Monthly net output averaged 7,660.13 MWhs during that same time period. Monthly net output for 2012 averaged 8,759.64 MWhs. This represents a greater than 10 % increase in average annual net output of 0 MWhs during the Historical Generation Baseline period. See Exhibit 1.

Because Indeck has demonstrated capital investments that were intended to and did add capacity in excess of 10%, and because the Facility had no output during the Baseline Period, Indeck requests certification of 100% of its Facility output as a Rhode Island New Renewable Energy Resource.

List of Exhibits:

Exhibit 1:	July 21, 2008 PSNH Letter
	July 21, 2008 NHDES Letter
Exhibit 2:	Calculation of Cost Basis
Exhibit 3:	Claimed Capability Audit Results
Exhibit 4:	CELT Reports
Exhibit 5:	Schedule of Capital Investments
Exhibit 6:	Output Chart

Exhibit 1

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
(603) 669-4000
www.psnh.com

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

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

Exhibit 2

Indeck Energy-Alexandria, LLC
PRODUCTION TAX CREDIT ELIGIBILITY

	Cost	Net Tax Value
Purchase Price Allocated to Inoperable Plant	1,194,667	555,215
Capital Improvements 2007/2008 - See Cost Study Report		
20 YR PROPERTY - Electric Steam Utility Production Plant	1,441,348	1,441,348
5 YR PROPERTY - Biomass Property	5,529,140	5,529,140
15 YR PROPERTY - Land Improvements	30,664	30,664
Total Capital Improvements 2007/2008	7,001,152	7,001,152
TOTAL	8,195,819	7,556,367
PERCENTAGE NEW	**85.42%**	**92.65%**

Indeck Energy-Alexandria, LLC

Cost Segregation Study

Indeck Alexandria Energy Center

March 2009

BDO

BDO Seidman, LLP
Accountants and Consultants

BDO

BDO Seidman, LLP
Accountants and Consultants

99 Monroe Avenue NW, Suite 800
Grand Rapids, Michigan 49503-2654
Telephone: (616) 774-7000
Fax: (616) 776-3680

March 25, 2009

Indeck Energy - Alexandria, LLC
c/o Mr. Joseph Oskorep
Vice President and Controller
Indeck Energy Services, Inc.
600 North Buffalo Grove Road
Suite 300
Buffalo Grove, Illinois 60089

Dear Mr. Oskorep:

We have completed our cost segregation analysis of the improvements to the Indeck Alexandria Energy Center in Alexandria, New Hampshire that Indeck Energy – Alexandria, LLC placed in service in December of 2008.

The federal tax classifications for these assets are detailed on the attached summary and Appendix A. If you have any questions regarding this report, please call Mark Zettell at (616) 774-7000.

Very truly yours,

BDO SEIDMAN, LLP

BDO Seidman LLP

Certified Public Accountants

cc: Bill Andreozzi (BDO Seidman, LLP – Chicago)
Paul Brocato (BDO Seidman, LLP – Chicago)

Following is a summary of the federal tax classifications for all assets reviewed by BDO Seidman, LLP during the course of this cost segregation study. Included in this report are all the relevant facts, assumptions and representations provided by Indeck Energy - Alexandria, LLC and relied upon by us to determine the proper federal tax depreciation classification under the Internal Revenue Code and related Income Tax Regulations. Consistent with the requirements under the final Circular 230 Regulations, we have used reasonable efforts to identify and ascertain the facts, assumptions and representations provided by Indeck Energy - Alexandria, LLC, upon which we have based our opinions, and we believe that such facts, assumptions and representations are reasonable. All applicable tax authorities upon which our opinions are based are described in this report.

The determinations expressed herein regarding asset classifications are not binding on the Internal Revenue Service (the "Service") and there can be no assurance that the Service will not take a position contrary to the asset classification conclusions expressed herein. However, should the Service challenge the federal asset classifications set forth on the following page, it is our opinion that, based solely on an analysis of the existing tax authorities relating to asset classifications, it is more likely than not that the asset classifications determined will be upheld. Accordingly, this opinion can be relied upon by Indeck Energy - Alexandria, LLC for the purpose of avoiding accuracy-related penalties that may be imposed.

This opinion is solely for the benefit of Indeck Energy - Alexandria, LLC and is not intended to be relied upon by any other party.

Indeck Alexandria Energy Center
In-Service December 2008

Project Cost Summary

General Contract – Yanke Energy	$ 3,298,017
Miscellaneous Contractors	2,863,481
Project Fees:	0
• Pre-Construction Services (Yanke Energy)	54,500
• General Fees	325,122
• UNICAP Costs	460,032
Total Project Cost	**$ 7,001,152**

Federal Tax Classifications

Biomass Property 5 Years – MACRS 200% Declining Balance (Note 2)	$ 5,529,140
Asset Class #00.3 – Land Improvements 15 Years – MACRS 150% Declining Balance (Note 2)	30,664
Asset Class #49.13 – Electric Steam Utility Production Plant 20 Years – MACRS 150% Declining Balance (Note 2)	1,441,348
Total Project Cost	**$ 7,001,152**

Notes:

1. See Appendix A for a detailed cost breakdown of all project related assets.
2. All 5-year, 15-year, and 20-year property qualifies for the 50% first-year bonus depreciation deduction.

Federal Tax Depreciation Classifications

A depreciation deduction is allowed by Section 168 of the Internal Revenue Code for property placed in service after December 31, 1980. This property is known as recovery property and is depreciated under the Modified Accelerated Cost Recovery System (MACRS). The class life for each asset guideline class under MACRS is set forth in Revenue Procedure 87-56, 1987-2 C.B. 674 (as clarified and modified by Rev. Proc. 88-22, 1988-1 C.B. 785). The deduction for depreciation of MACRS property is determined by using the applicable:

- Method of depreciation,
- Recovery period, and
- Convention.

There are three specified methods, eight recovery periods, and three specified conventions. Which of each applies to a particular property depends largely on the class into which the property falls. Generally, under MACRS, assets used in the steam power production of electricity for sale are generally depreciated over twenty years using the 200% declining balance method, with a switch to the straight-line method in the first year for which the use of such method results in a larger deduction. Assets that are "biomass property" as described in IRC Sec. 48(l)(15) may be depreciated over five years. All land improvements are depreciated over 15 years using the 150% declining balance method with a similar provision for switching to the straight-line method.

MACRS provides conventions for determining the period of time for which depreciation may be claimed in the year the property is placed in service. Generally, the half-year convention applies to all personal and land improvement property, and the mid-month convention applies to all non-residential real property and residential rental property. However, the mid-quarter convention must be used for all personal and land improvement property if the aggregate basis of the personal and land improvement property placed in service during the last three months of the taxable year is more than 40% of all such property placed in service during the entire year.

The "Job Creation and Worker Assistance Act of 2002" allows a taxpayer to claim an additional first year depreciation deduction equal to 30% of the basis of qualified property. Qualified property is generally property with a recovery period of 20 years or less which was placed in service on or after September 11, 2001, and for which no binding written contract to acquire or construct was in effect prior to this date. The "Jobs and Growth Tax Relief Reconciliation Act of 2003" increased the amount of bonus depreciation to 50% for all qualifying property placed in service after May 5, 2003, and for which no binding written contract to acquire or construct was in effect prior to this date. This act also extended the expiration date for all bonus depreciation until December 31, 2004. The Economic Stimulus Act of 2008 and the American Recovery and

Reinvestment Act of 2009 temporarily reinstated the 50% bonus depreciation deduction for assets acquired after December 31, 2007 and placed in-service prior to January 1, 2010. For the project in question, all 5-year, 15-year and 20-year assets qualify for the 50% first-year bonus depreciation deduction. No AMT depreciation adjustment is required for assets that qualify for the first-year bonus depreciation deduction.

The relevant property classifications for the project related assets are defined as follows:

- ***Biomass Property (5-Year Property)***

  Wood is considered a "biomass," and wood chips are used as the source of fuel at the Indeck Alexandria Energy Center. Rev. Proc. 87-56 provides that "biomass property," which is described in IRC Sec. 48(1)(15), has a MACRS recovery period of five years. For the project in question, "biomass property" generally includes the boiler and all ancillary systems and pieces of equipment, the material handling equipment and structures that are used to unload, transfer, store and re-claim the wood chips, and all emission control equipment.

- ***Asset Class #00.3 – Land Improvements (15-Year Property)***

  Class #00.3 includes improvements directly on or added to land, whether such improvements are Section 1245 property or Section 1250 property, provided such improvements are depreciable. Typical land improvement assets include asphalt roadways and parking areas, site concrete, site utilities, and landscaping and irrigation.

- ***Asset Class #49.13 – Electric Utility Steam Production Plant (20-Year Property)***

  Class #49.13 includes assets used in the steam power production of electricity for sale, combustion turbines operated in a combined cycle with a conventional steam unit, and related land improvements. For the project in question, this asset class includes the turbine system, the electrical interconnect with the utility, water treatment system, and all other plant related assets that are not "biomass property."

Appendix A

Federal Tax Classifications

INDECK ENERGY - ALEXANDRIA, LLC

INDECK ALEXANDRIA ENERGY CENTER RENOVATION

(IN-SERVICE DECEMBER 2008)

APPENDIX A

DESCRIPTION	ITEM COST	ALLOCATIONS: GENERAL CONTRACT ALLOCABLES	ALLOCATIONS: PRE CONSTR. SERVICES	ALLOCATIONS: GENERAL FEES	ALLOCATIONS: INTERNAL LABOR / ADMIN.	ALLOCATIONS: INTEREST	TOTAL ITEM COST	FEDERAL TAX CLASSIFICATIONS: BIOMASS 5 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #00.3 15 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #49.13 20 YEAR PROPERTY
GENERAL CONTRACT - YANKE ENERGY										
CONSTRUCTION										
WATER SYSTEM - FRESH WATER (COOLING TOWERS)										
RIVER WATER MAKE-UP PUMPS	8,240	1,737	164	478	619	57	11,294			11,294
RIVER WATER TRANSFER PUMPS	9,000	1,897	179	522	676	62	12,336			12,336
ADDITIONAL PUMPS	2,320	489	46	134	174	16	3,180			3,180
ELECTRICAL (BOILER AND EMISSIONS CONTROL)										
CONTROL PANEL	20,000	4,216	397	1,159	1,502	138	27,413	27,413		
INSTRUMENTATION AND CONTROL	125,700	26,498	2,496	7,287	9,443	868	172,291	172,291		
MOTOR CONTROL CENTERS	7,500	1,581	149	435	563	52	10,280	10,280		
TERMINATIONS	20,000	4,216	397	1,159	1,502	138	27,413	27,413		
BOILER										
BOILER	350,000	73,780	6,949	20,289	26,292	2,416	479,727	479,727		
AIR PRE-HEATER	10,000	2,108	199	580	751	69	13,706	13,706		
FORCED DRAFT FAN AND DUCTING	11,934	2,516	237	692	896	82	16,357	16,357		
INDUCED DRAFT FAN AND DUCTING	20,620	4,347	409	1,195	1,549	142	28,263	28,263		
OVER-FIRE AIR DUCTING AND CONTROLS	390,000	82,212	7,743	22,608	29,297	2,692	534,553	534,553		
VALVES AND PIPING	40,000	8,432	794	2,319	3,005	276	54,826	54,826		
HIGH PRESSURE ECONOMIZER	10,000	2,108	199	580	751	69	13,706	13,706		
BOILER SUPPORT										
BOILER FEED PUMPS AND DRIVES	98,910	20,850	1,964	5,734	7,430	683	135,571	135,571		
FEEDWATER CONTROL VALVE	2,600	548	52	151	195	18	3,564	3,564		
TURBINE SYSTEM										
MAIN STEAM LINE	20,000	4,216	397	1,159	1,502	138	27,413			27,413
CONDENSER	16,000	3,373	318	928	1,202	110	21,930			21,930
AIR EJECTOR VACUUM PUMP	11,000	2,319	218	638	826	76	15,077			15,077
CONDENSATE PUMPS AND PIPING	12,680	2,673	252	735	953	88	17,380			17,380
CONDENSATE CONTROL VALVES	2,500	527	50	145	188	17	3,427			3,427
COOLING TOWER	40,000	8,432	794	2,319	3,005	276	54,826			54,826
CIRCULATION WATER PUMPS AND PIPING	18,560	3,912	368	1,076	1,394	128	25,439			25,439
EMISSION CONTROL										
MULTICLONE	110,000	23,188	2,184	6,377	8,263	759	150,771	150,771		
ELECTROSTATIC PRECIPITATOR	450,000	94,860	8,934	26,086	33,805	3,106	616,792	616,792		
STACK	5,000	1,054	99	290	376	35	6,853	6,853		
ASH HANDLING - WET DOWN	3,800	801	75	220	285	26	5,208	5,208		
FLY ASH REINJECTION	16,515	3,481	328	957	1,241	114	22,636	22,636		
ASH CONVEYING	30,060	6,337	597	1,743	2,258	208	41,202	41,202		
AMMONIA INJECTION STORAGE	58,800	12,395	1,167	3,409	4,417	406	80,594	80,594		

INDECK ENERGY - ALEXANDRIA, LLC

INDECK ALEXANDRIA ENERGY CENTER RENOVATION

(IN-SERVICE DECEMBER 2008)

APPENDIX A

DESCRIPTION	ITEM COST	ALLOCATIONS: GENERAL CONTRACT ALLOCABLES	ALLOCATIONS: PRE CONSTR. SERVICES	ALLOCATIONS: GENERAL FEES	ALLOCATIONS: INTERNAL LABOR / ADMIN.	ALLOCATIONS: INTEREST	TOTAL ITEM COST	FEDERAL TAX CLASSIFICATIONS: BIOMASS 5 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #00.3 15 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #49.13 20 YEAR PROPERTY
SNCR	380,000	80,104	7,545	22,029	28,546	2,623	520,847	520,847		
AMMONIA SCRUBBER	321,750	67,825	6,388	18,652	24,170	2,221	441,006	441,006		
TOTAL CONSTRUCTION	2,623,489									
ALLOCABLES										
ADMINISTRATION										
PROCESS DESIGN	10,000									
PROJECT MANAGEMENT	142,500									
PURCHASING	28,333									
START UP / TRAINING	52,200									
FIELD / SHOP SUPERVISION	25,000									
TRAVEL AND PER DIEM	78,000									
EQUIPMENT RENTAL	96,000									
FREIGHT	15,000									
TOOLS AND CONSUMABLES	50,000									
START-UP ITERATIONS	56,000									
TOTAL ALLOCABLES	553,033	553,033								
CHANGE ORDERS										
1. SAFETY RELIEF VALVES (BOILER)	6,499		129	377	488	45	7,538	7,538		
2. FIRE WATER PUMP - INSPECTION	725		14	42	54	5	841			841
3. DEMINERALIZER PUMPS - INSPECTION (BOILER)	6,400		127	371	481	44	7,423	7,423		
4. OVER-FIRE AIR FAN - SPLIT SPHERICAL BEAM (BOILER)	2,318		46	134	174	16	2,688	2,688		
5. YARWAY ARC VALVES (BOILER)	10,160		202	589	763	70	11,784	11,784		
6. LABYRINTH SEAL, SPARE MOTORS (BOILER)	12,294		244	713	924	85	14,259	14,259		
7. INSTALL 48 TRANSMITTERS (EMISSION CONTROL)	16,718		332	969	1,256	115	19,390	19,390		
8. SET FIRE WATER PUMP	1,209		24	70	91	8	1,402			1,402
9 REMOVE CAP FROM PRECIPITATOR STACK	2,474		49	143	186	17	2,869	2,869		
10. BOILER FEED WATER CONTROL VALVE	21,603		429	1,252	1,623	149	25,056	25;056		
11. OIL FOR INDUCED DRAFT FAN (BOILER)	156		3	9	12	1	181	181		
12. CLARK-RELIANCE PC-41 CONTROL BOARD (BOILER)	2,644		52	153	199	18	3,067	3,067		
13. REFRACTORY REPAIRS (BOILER)	4,198		83	243	315	29	4,868	4,868		
14. 5 - 20" DISTRIBUTOR PLATES (BOILER)	7,099		141	411	533	49	8,233	8,233		
15. CIRC. WATER PIPE FOR FLUSHING	9,213		183	534	692	64	10,685			10,685
16. METERING BIN (BOILER)	3,046		60	177	229	21	3,533	3,533		

INDECK ENERGY - ALEXANDRIA, LLC
INDECK ALEXANDRIA ENERGY CENTER RENOVATION
(IN-SERVICE DECEMBER 2008)

APPENDIX A

DESCRIPTION	ITEM COST	ALLOCATIONS: GENERAL CONTRACT ALLOCABLES	ALLOCATIONS: PRE CONSTR. SERVICES	ALLOCATIONS: GENERAL FEES	ALLOCATIONS: INTERNAL LABOR / ADMIN.	ALLOCATIONS: INTEREST	TOTAL ITEM COST	FEDERAL TAX CLASSIFICATIONS: BIOMASS 5 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #00.3 15 YEAR PROPERTY	FEDERAL TAX CLASSIFICATIONS: CLASS #49.13 20 YEAR PROPERTY
17. RORORK VALVE ACTUATOR (BOILER)	7,740		154	449	581	53	8,977	8,977		
18. ID FAN / FD FAN / OFA FAN SWITCHGEAR (BOILER)	7,000		139	406	526	48	8,119	8,119		
TOTAL CHANGE ORDERS	121,495									
TOTAL GENERAL CONTRACT	3,298,017									
MISCELLANEOUS CONTRACTORS										
MISC. TURBINE BUILDING / OFFICE CONSTRUCTION	13,359			774	1,004	92	15,230			15,230
SITE WORK, GROUNDS - ASPHALT PAVING AND SEALCOATING	26,899			1,559	2,021	186	30,664		30,664	
HVAC	19,829			1,149	1,490	137	22,605			22,605
AIR COMPRESSOR SYSTEM	24,248			1,406	1,822	167	27,642			27,642
FIRE PROTECTION SYSTEM	12,102			702	909	84	13,796			13,796
STACK	2,128			123	160	15	2,426	2,426		
OTHER BUILDING	37,826			2,193	2,842	261	43,121			43,121
ELECTRICAL INTERCONNECT - UTILITY	415,004			24,058	31,176	2,865	473,102			473,102
TRANSFORMER / BACKFEED ELECTRICAL	66,291			3,843	4,980	458	75,571			75,571
CONTROL SYSTEM / INSTRUMENTATION (BOILER)	383,999			22,260	28,847	2,651	437,756	437,756		
OTHER PLANT ELECTRICAL (BOILER)	176,538			10,234	13,262	1,219	201,252	201,252		
WATER SUPPLY (COOLING TOWERS)	85,416			4,952	6,417	590	97,374			97,374
SEWER SYSTEM / SEPTIC	13,332			773	1,002	92	15,198			15,198
POTABLE WATER SYSTEM	6,989			405	525	48	7,967			7,967
TRUCK DUMPS (FUEL MATERIAL HANDLING)	68,561			3,974	5,150	473	78,159	78,159		
CONVEYOR (FUEL MATERIAL HANDLING)	30,334			1,758	2,279	209	34,581	34,581		
FUEL OIL SYSTEM (BOILER)	55,204			3,200	4,147	381	62,933	62,933		
OTHER FUEL SYSTEM (BOILER)	112,945			6,547	8,485	780	128,757	128,757		
BOILER STRUCTURE, REFACTORY	47			3	4	0	53	53		
FANS AND DUCTING (BOILER)	518			30	39	4	590	590		
BOILER PRESSURE PARTS	9,025			523	678	62	10,288	10,288		
VALVES AND PIPING (BOILER)	66,051			3,829	4,962	456	75,298	75,298		
SOOT BLOWERS	2,428			141	182	17	2,768	2,768		
TRAVELING GRATE (BOILER)	88,585			5,135	6,655	612	100,987	100,987		
BOILER FEED PUMPS	89,211			5,172	6,702	616	101,700	101,700		
DEAERATOR	3,228			187	242	22	3,680	3,680		
OTHER BOILER	106,738			6,188	8,018	737	121,681	121,681		
WATER TREATMENT (BOILER)	166,457			9,649	12,504	1,149	189,759	189,759		
TURBINE/GENERATOR SYSTEM	389,924			22,604	29,292	2,692	444,511			444,511
CEMS SYSTEM (EMISSION CONTROL)	263,851			15,295	19,821	1,821	300,789	300,789		

INDECK ENERGY - ALEXANDRIA, LLC
INDECK ALEXANDRIA ENERGY CENTER RENOVATION
(IN-SERVICE DECEMBER 2008)

APPENDIX A

DESCRIPTION	ITEM COST	ALLOCATIONS: GENERAL CONTRACT ALLOCABLES	PRE CONSTR. SERVICES	GENERAL FEES	INTERNAL LABOR / ADMIN.	INTEREST	TOTAL ITEM COST	FEDERAL TAX CLASSIFICATIONS: BIOMASS 5 YEAR PROPERTY	CLASS #00.3 15 YEAR PROPERTY	CLASS #49.13 20 YEAR PROPERTY
ASH HANDLING	121,092			7,020	9,097	836	138,044	138,044		
OTHER EMISSION CONTROL	5,324			309	400	37	6,069	6,069		
TOTAL MISC. CONTRACTORS	2,863,481									
PROJECT FEES										
PRE-CONSTRUCTION SERVICES (YANKE ENERGY)										
INITIAL SITE VISIT / INSPECTION	39,500									
PERFORMANCE BOND PREMIUM	15,000									
TOTAL PRE-CONSTRUCTION SERVICES	54,500		54,500							
GENERAL FEES										
PLANT LABOR	6,058									
TRAVEL EXPENSE	194,145									
LEGAL (NON FINANCIAL)	17,398									
PROFESSIONAL / CONSULTING / TECHNICAL	77,156									
WASTE DISPOSAL	29,655									
LEGAL, BANK	709									
TOTAL GENERAL FEES	325,122			325,122						
UNICAP FEES										
INTERNAL LABOR	421,316				421,316					
CONSTRUCTION PERIOD INTEREST	38,717					38,717				
TOTAL UNICAP FEES	460,032									
TOTAL PROJECT FEES	839,654									
TOTAL PROJECT COST	7,001,152						7,001,152	5,529,140 (NOTE 1)	30,664 (NOTE 1)	1,441,348 (NOTE 1)

NOTES

1. ALL 5-YEAR, 15-YEAR AND 20-YEAR ASSETS QUALIFY FOR THE 50% FIRST-YEAR BONUS DEPRECIATION DEDUCTION.

Exhibit 3

Claimed Capability Audit – Notification of Results

In accordance with the provisions of the M-RPA Manual, a Claimed Capability Audit (CCA) has been conducted on your Generator Asset. This is the notification of results of the CCA.

Audit ID#	7707	Audit Date:	03/29/12
Demonstration Period:	Winter	Demonstration Year:	2012
Asset Name:	INDECK ALEXANDRIA	EMS Short Name:	ALEX
Asset ID #:	14211	Asset Audit Type:	F

	Winter	Summer
Seasonal Claimed Capability (SCC) at time audit was	14.614	11.364

Audit Type: CCA-Establish

Date Audit Requested (CCA-Establish, CCA-Restore, CCA-Retest): Date Designation of Audit received by ISO-NE (CCA-Test):	3/22/12 16:37
Date and Time of Audit Start (Hour ending, 1-24):	3/27/12 10:00
Date and Time of Audit End (Hour ending, 1-24):	3/27/2012 13:00

Audit Details

Audit Duration Hours: 4

Date and HE of Audit:	Net MW Output (RQM)	Station Service Load	Gross MW Output
3/27/2012 10:00	15.691	1.745	17.412
3/27/2012 11:00	15.657	1.725	17.358
3/27/2012 12:00	15.678	1.738	17.391
3/27/2012 13:00	15.558	1.719	17.248
Average Output Demonstrated, unadjusted (MW):	15.646	1.732	17.352

Adjustment Data, if Applicable

	Temperature (degrees F)	Steam Exports (lbs./hr.)
HE		
HE		
HE		
HE		
HE		
HE		
HE		
HE		
Avg. Temp.	#DIV/0!	

For Units Requiring Temperature and/or Steam Export Adjustment

Average Output Demonstrated, Adjusted for Temperature and/or Steam Exports - **Winter** (MW):	
Average Output Demonstrated, Adjusted for Temperature and/or Steam Exports - **Summer** (MW):	
Audit Result:	Successful

Actions required with comments

This was a successful CCA-Establish and the WSCC will be effective as stated in the NX-12 revision that was submitted with the request.

Ask ISO Issue# 6367 was created and assigned to this CCA-Establish.

	Name	*Telephone #*	*E-mail*
Audit Results processed by:	**Jason Schulte**	**413-535-4093**	jschulte@iso-ne.com

Claimed Capability Audit – Notification of Results

In accordance with the provisions of the M-RPA Manual, a Claimed Capability Audit (CCA) has been conducted on your Generator Asset. This is the notification of results of the CCA.

Audit ID#	7839	Audit Date:	07/03/12
Demonstration Period:	Summer	Demonstration Year:	2012
Asset Name:	INDECK ALEXANDRIA	EMS Short Name:	ALEX
Asset ID #:	14211	Asset Audit Type:	F

	Winter	Summer
Seasonal Claimed Capability (SCC) at time audit was	15.2	11.364

Audit Type: CCA-Establish

Date Audit Requested (CCA-Establish, CCA-Restore, CCA-Retest): Date Designation of Audit received by ISO-NE (CCA-Test):	6/12/12 3:36
Date and Time of Audit Start (Hour ending, 1-24):	6/29/12 15:00
Date and Time of Audit End (Hour ending, 1-24):	6/29/12 18:00

Audit Details

Audit Duration Hours: 4

Date and HE of Audit:	Net MW Output (RQM)	Station Service Load	Gross MW Output
6/29/2012 15:00	14.945	1.691	16.607
6/29/2012 16:00	14.695	1.654	16.323
6/29/2012 17:00	15.097	1.678	16.745
6/29/2012 18:00	15.388	1.694	17.055
Average Output Demonstrated, unadjusted (MW):	15.031	1.679	16.683

Adjustment Data, if Applicable

	Temperature (degrees F)	Steam Exports (lbs./hr.)
HE		
HE		
HE		
HE		
HE		
HE		
HE		
HE		
Avg. Temp.		

For Units Requiring Temperature and/or Steam Export Adjustment

Average Output Demonstrated, Adjusted for Temperature and/or Steam Exports - **Winter** (MW):	0.000
Average Output Demonstrated, Adjusted for Temperature and/or Steam Exports - **Summer** (MW):	0.000
Audit Result:	**Successful**

Actions required with comments

This was a successful CCA-Establish however the asset did not meet or beat the submitted target SCC. ISO New England adjusted the Summer SCC to the demonstrated amount. No further action is required.□ Ask ISO Issue #8912 was created and assigned to this CCA-Establish.□

	Name	*Telephone #*	*E-mail*
Audit Results processed by:	**Jim Nichols**	**413-540-4678**	jnichols@iso-ne.com

Exhibit 4

3.2 Expected Summer Capability by Fuel/Unit Type

BIO/REFUSE

463	AEI LIVERMORE	34.695	14271	AMERESCO NORTHAMPTON	0.000	790	APLP-BFI	0.000
953	ATTLEBORO LANDFILL - QF	0.353	1059	BARRE LANDFILL	0.840	12180	BERKSHIRE COW POWER	0.500
337	BETHLEHEM	15.672	342	BIO ENERGY	0.000	10615	BLUE SPRUCE FARM U5	0.275
590	BORALEX STRATTON ENERGY	45.024	11154	BRATTLEBORO LANDFILL	0.500	357	BRIDGEWATER	15.701
356	BRISTOL REFUSE	13.200	973	CONCORD STEAM	0.374	14707	COVANTA HAVERHILL - LF GAS	0.000
446	COVANTA JONESBORO	23.117	445	COVANTA WEST ENFIELD	23.206	10801	COVENTRY CLEAN ENERGY	4.719
12323	COVENTRY CLEAN ENERGY #4	1.585	1209	CRRA HARTFORD LANDFILL	1.893	15998	Crossroads Landfill	0.000
618	DG WHITEFIELD, LLC	14.873	942	DUNBARTON ROAD LANDFILL	0.515	13669	EAST WINDSOR NORCAP LFG	0.000
1052	EB1-BFI	1.804	542	ECO MAINE	11.663	14382	ETHAN ALLEN CO-GEN 1	0.299
411	EXETER	24.174	943	FOUR HILLS LANDFILL	0.124	194	FOUR HILLS LOAD REDUCER	1.645
1572	GRANBY SANITARY LANDFILL QF U5	2.800	12274	GREEN MOUNTAIN DAIRY	0.166	429	GREENVILLE	16.726
1432	GRS-FALL RIVER	3.113	11052	GRTR NEW BEDFORD LFG UTIL	3.300	1051	HAL-BFI	1.056
436	HEMPHILL 1	14.130	14211	INDECK ALEXANDRIA	13.882	1259	J & L ELECTRIC - BIOMASS I	0.000
10566	J & L ELECTRIC - BIOMASS II	0.000	474	J C MCNEIL	52.000	451	JOHNSTON LANDFILL	11.962
462	LISBON RESOURCE RECOVERY	12.961	476	MERC	19.978	954	MM LOWELL LANDFILL - QF	0.224
1109	MMWAC	2.340	14134	MONTAGNE FARM	0.219	15488	Middleton Building Supply	0.000
15617	Moretown LFGTE	0.000	978	NEW MILFORD	2.223	15465	Neighborhood Energy, LLC	0.000
527	OGDEN-MARTIN 1	40.111	536	PERC-ORRINGTON 1	20.851	809	PINCHBECK	0.000
538	PINETREE POWER	16.620	2462	PLAINVILLE GEN QF U5	3.670	952	PONTIAC ENERGY - QF	0.167
12163	PPL GREAT WORKS - RED SHIELD	3.683	14767	Pine Tree LFGTE	2.870	1224	RANDOLPH/BFG ELECTRIC FACILITY	1.168
546	RESCO SAUGUS	32.725	715	ROCHESTER LANDFILL	4.595	10366	RRIG EXPANSION PHASE 1	2.400
10959	RRIG EXPANSION PHASE 2	5.204	2433	RYEGATE 1-NEW	20.500	591	S.D. WARREN-WESTBROOK	42.590
557	SCHILLER 5	43.082	562	SECREC-PRESTON	16.011	563	SEMASS 1	46.180
564	SEMASS 2	20.850	767	SES CONCORD	12.513	881	SHELTON LANDFILL	0.000
580	SO. MEADOW 5	25.596	581	SO. MEADOW 6	27.113	1107	SOMERSET	1.607
2425	SPRINGFIELD REFUSE-NEW	6.000	592	TAMWORTH	21.000	1302	TCPMCMPAGF GEN1 U5	0.000
253	TURNKEY LANDFILL	3.041	623	WALLINGFORD REFUSE	6.350	956	WARE COGEN - QF	0.000
14098	WASTE MANAGEMENT LANDFILL	2.801	10451	WESTFIELD #1 U5	0.121	349	WHEELABRATOR BRIDGEPORT, L.P.	58.517
10404	WHEELABRATOR CLAREMONT U5	4.218	547	WHEELABRATOR NORTH ANDOVER	30.996	624	WMI MILLBURY 1	39.811
629	WORCESTER ENERGY	17.959	14919	ZBE-001	0.000			

Total Summer Capacity = 974.751

COAL STEAM

594	AES THAMES	181.000	350	BRAYTON PT 1	243.455	351	BRAYTON PT 2	244.000
352	BRAYTON PT 3	612.000	340	BRIDGEPORT HARBOR 3	383.426	345	MEAD	0.000
489	MERRIMACK 1	112.500	490	MERRIMACK 2	320.000	498	MT TOM	143.619
551	SALEM HARBOR 1	79.055	552	SALEM HARBOR 2	76.946	553	SALEM HARBOR 3	144.598
556	SCHILLER 4	47.500	558	SCHILLER 6	47.938	577	SOMERSET 6	109.058

Total Summer Capacity = 2745.095

NOTES:
Gas/oil units are not necessarily be fully operable on both fuels.

2.3 Existing Winter Capability by Fuel/Unit Type

SCC as of 2011/12 Winter Peak

BIO/REFUSE

194	FOUR HILLS LOAD REDUCER	1.084
253	TURNKEY LANDFILL	1.286
337	BETHLEHEM	15.201
349	WHEELABRATOR BRIDGEPORT, L.P.	59.270
356	BRISTOL REFUSE	12.693
357	BRIDGEWATER	14.146
411	EXETER	20.831
429	GALLOP POWER GREENVILLE	13.805
436	HEMPHILL 1	16.860
445	COVANTA WEST ENFIELD	21.446
446	COVANTA JONESBORO	20.226
451	JOHNSTON LANDFILL	12.000
462	LISBON RESOURCE RECOVERY	13.649
463	REENERGY LIVERMORE FALLS	34.430
474	J C MCNEIL	54.000
476	MERC	16.097
527	OGDEN-MARTIN 1	42.106
536	PERC-ORRINGTON 1	20.847
538	PINETREE POWER	16.787
542	ECO MAINE	10.233
546	RESCO SAUGUS	30.114
547	WHEELABRATOR NORTH ANDOVER	29.837
557	SCHILLER 5	42.594
562	SECREC-PRESTON	16.651
563	SEMASS 1	50.118
564	SEMASS 2	25.236
580	SO. MEADOW 5	28.476
581	SO. MEADOW 6	20.367
590	REENERGY STRATTON	44.363
591	S.D. WARREN-WESTBROOK	49.103
592	TAMWORTH	18.302
618	DG WHITEFIELD, LLC	17.034
623	COVANTA PROJECTS WALLINGFORD	4.221
624	WMI MILLBURY 1	39.891
629	DOWNEAST POWER	0.000
715	ROCHESTER LANDFILL	2.261

BIO/REFUSE

767	SES CONCORD	12.492
809	PINCHBECK	0.000
881	SHELTON LANDFILL	0.000
942	DUNBARTON ROAD LANDFILL	0.290
943	FOUR HILLS LANDFILL	0.000
952	PONTIAC ENERGY - QF	0.104
953	ATTLEBORO LANDFILL - QF	0.216
954	MM LOWELL LANDFILL - QF	0.122
956	WARE COGEN - QF	0.000
973	CONCORD STEAM	0.224
978	NEW MILFORD	1.544
1051	HAL-BFI	0.000
1052	EB1-BFI	0.000
1059	BARRE LANDFILL	0.743
1107	SOMERSET	0.000
1109	MMWAC	2.073
1209	CRRA HARTFORD LANDFILL	1.705
1224	RANDOLPH/BFG ELECTRIC FACILITY	0.000
1259	J & L ELECTRIC - BIOMASS I	0.000
1302	TCPMCMPAGF GEN1 U5	0.000
1432	GRS-FALL RIVER	3.824
1572	GRANBY SANITARY LANDFILL QF	3.092
2425	SPRINGFIELD REFUSE-NEW	5.777
2433	RYEGATE 1-NEW	20.720
2462	PLAINVILLE GEN QF U5	2.944
10366	RRIG EXPANSION PHASE 1	0.000
10404	WHEELABRATOR CLAREMONT U5	3.444
10451	WESTFIELD #1 U5	0.000
10615	BLUE SPRUCE FARM	0.144
10801	COVENTRY CLEAN ENERGY	3.600
10959	RRIG EXPANSION PHASE 2	4.999
11052	GRTR NEW BEDFORD LFG UTIL PROJ	2.431
11154	BRATTLEBORO LANDFILL	0.000
12163	PPL GREAT WORKS - RED SHIELD	0.000
12180	BERKSHIRE COW POWER	0.332
12274	GREEN MOUNTAIN DAIRY	0.235

BIO/REFUSE

12323	COVENTRY CLEAN ENERGY #4	2.400
12509	UNH POWER PLANT	4.478
13669	EAST WINDSOR NORCAP LFG PLANT	0.927
14098	FITCHBURG LANDFILL	4.207
14134	MONTAGNE FARM	0.064
14211	INDECK ALEXANDRIA	15.200
14271	AMERESCO NORTHAMPTON	0.000
14382	ETHAN ALLEN CO-GEN 1	0.000
14707	COVANTA HAVERHILL - LF GAS	1.340
14767	PINE TREE LFGTE	2.397
14919	ZBE-001	0.000
15465	NEIGHBORHOOD ENERGY, LLC	0.000
15488	MIDDLETON BUILDING SUPPLY	0.000
15617	MORETOWN LFGTE	3.008
15998	CROSSROADS LANDFILL	2.976
16331	QUARRY ENERGY PROJECT	0.382
17259	SEAMAN ENERGY LLC	0.475
40050	EXETER AGRI ENERGY	0.980
Total Winter Capability:		**945.454**

APPENDIX B - Existing Non-Utility Generators
B.2 - Claimed Thermal Non-Utility Capability as of January 1, 1994

CC (1)	JO (2)	PURCHASING SYSTEM	STATION NAME AND NO.	LOCATION TOWN	LOCATION STATE	STATUS	LOCATION		UNIT TYPE	NOV. 1991 GOV. RPT. (3) CAPACITY (MW) NAMEPLATE	NOV. 1991 GOV. RPT. (3) CLASS	CLAIMED CAPABILITY-MW (4) SUMMER CAPACITY	CLAIMED CAPABILITY-MW (4) WINTER CAPACITY	ESTIMATED ANNUAL ENERGY FLOW TO GRID (MW HRS)	FUEL TYPE	ALT FUEL TYPE	START YR.MO	END YR.MO
		01	02				03		04			05	06		07	09		
0		NU	Bio-Energy Corp	W. Hopkinton	NH	OP	33	013	ST	12.50	SP	9.00	9.00	78000	WD		1984.11	2014.01
2		CMP	Scott-SD Warren (Westbrook)	Westbrook	ME	OP	23	005	ST	62.50	CG	43.07	48.65	377994	WD	OIL	1985.04	1997.10
2		NEP	Mass Refuse Tech (Neswc-Resco)	N. Andover	MA	OP	25	009	ST	32.23	SP	31.79	31.98	227025	REF		1985.08	2005.06
2		NEP	Refuse Engy Co (Saug 1)	Saugus	MA	OP	25	009	ST	29.00	SP	29.94	29.01	226200	REF		1985.11	2015.12
2		NU	Timco Inc.	Center Barnstead	NH	OP	33	011	ST	4.80	SP	3.85	3.80	28000	WD		1985.11	2005.01
0		MMWEC	Refuse Fuels Associates (Lawrence)	Lawrence	MA	OP	25	009	ST	10.00	CG	10.00	10.00	35000	REF		1986.01	2006.01
0		NU	Concord Steam Corp.	Concord	NH	OP	33	013	ST	1.30	SP	0.00	1.34	4800	WD		1986.10	2004.01
2		BHE	Beaverwood AED 1	Chester	ME	OP	23	019	ST	15.50	SP	15.43	15.44	90341	BIO	WD	1986.11	1994.06
0		NU	Bethlehem Project	Bethlehem	NH	OP	33	007	ST	17.10	SP	15.00	15.00	125000	WD		1986.12	2006.01
2	E	BHE	Ultrapower 5 (West Enfield)	West Enfield	ME	OP	23	019	ST	25.10	SP	15.13	15.36	2352	WD		1987.01	2002.10
2	F	BHE	Ultrapower 6 (Jonesboro)	Jonesboro	ME	OP	23	029	ST	25.10	SP	15.43	15.64	9798	WD		1987.01	2002.10
2		CMP	Swift River (Greenville)	Greenville	ME	OP	23	021	ST	13.80	NA	15.47	14.82	75560	WD	OIL	1987.03	2007.02
2		CMP	Maine Energy Recovery Corp.	Biddeford	ME	OP	23	031	ST	19.47	SP	19.35	19.38	159982	REF		1987.05	2007.05
2		VTGP	NH/VT Solid Waste	Claremont	NH	OP	33	019	ST	3.43	SP	3.59	4.00	37022	REF		1987.08	2007.01
0		MMWEC	Carbalon (Sterling Dsl #1)	Sterling	MA	OP	25	027	IC	0.33	IP	0.33	0.33	100	OIL		1987.08	1998.11
0		NEP	Wheelabrator Millbury Inc.	Millbury	MA	OP	25	027	ST	40.10	SP	39.39	40.10	331116	REF		1987.09	2017.09
0		NU	Bridgewater Steam	Bridgewater	NH	OP	33	009	ST	20.00	SP	15.00	15.00	127000	WD		1987.09	2006.01
2		NU	Mid Conn (Hartford CRRA) #5&6	Hartford	CT	OP	09	003	ST	65.60	SP	64.10	63.71	402995	REF		1987.11	2011.09
2	E	UNITIL	Ultrapower 5 (West Enfield)	West Enfield	ME	OP	23	019	ST	N/L	NA	9.50	9.50	832	WD		1987.11	2002.10
2	F	UNITIL	Ultrapower 6 (Jonesboro)	Jonesboro	ME	OP	23	029	ST	N/L	NA	9.50	9.50	1664	WD		1987.11	2002.10
0		NU	Alexandria Power	Alexandria	NH	OP	33	009	ST	16.08	SP	15.00	15.00	124000	WD		1987.12	2007.01
0		NU	Hemphill Pwr&Lt Co	Springfield	NH	OP	33	019	ST	16.00	SP	13.80	13.80	119000	WD		1987.12	2006.01
0		CMP	Gorbell Inc (Thermo Electron)	Athens	ME	OP	23	025	ST	13.65	SP	13.74	14.13	86786	WD		1987.12	2007.12
0		NU	Tamworth Project	Tamworth	NH	OP	33	003	ST	26.00	SP	20.00	20.00	168000	WD		1988.01	2007.01
2	G	BHE	Penobscot Energy Recovery (PERC)	Orrington	ME	OP	23	019	ST	22.00	SP	15.76	15.93	134107	REF		1988.01	2003.02
2		CMP	Fairfield Energy Venture (5)	Fort Fairfield	ME	OP	23	003	ST	32.00	SP	32.00	32.00	237527	WD		1988.01	2002.11
0		NU	Whitefield Power & Light	Whitefield	NH	OP	33	007	ST	16.06	SP	13.80	13.80	116000	WD		1988.04	2005.01
0		UI	Signal/Resco (Bpt CRRA)	Bridgeport	CT	OP	09	001	ST	62.00	SP	62.00	62.00	499320	REF		1988.04	2008.04
2		NU	Bristol Refuse	Bristol	CT	OP	09	003	ST	13.20	SP	13.20	13.20	98900	REF	OIL	1988.05	2012.11
2		NU	Flagg/Hartford Hosp. (CCF-1)	Hartford	CT	OP	09	003	CW	16.60	CG	8.89	10.15	63771	NG	OIL	1988.06	2008.11

FOOTNOTES:

(1) CODES FOR COLUMN CC: 0-NO CHANGES; 1-NEW UNIT; 2-DATA CHANGES FROM 1993 CELT REPORT.
(2) CODES FOR COLUMN JO: LETTERS IDENTIFY PROJECTS WITH MULTIPLE PURCHASING SYSTEMS. SEE APPENDIX A.5.
(3) SHOWN FOR INFORMATIONAL PURPOSES ONLY.
(4) BASED ON 1/1/94 NEW ENGLAND POWER EXCHANGE (NEPEX) NET CLAIMED CAPABILITY REPORT.
(5) CAPABILITY NOT INCLUDED IN THE NON-UTILITY TOTALS (LOCATED OUTSIDE THE NEPOOL SERVICE TERRITORY); AMOUNT CLAIMED FOR CAPABILITY TRANSFERRED OVER THE NEW BRUNSWICK TIE LINE (SEE PAGE 29).

APPENDIX G - 1994 CELT Reported Non-Utility Generation Not Included as of January 1, 1995

G.1 - Deactivated Reserve

TYPE (1)	PURCHASING SYSTEM	STATION NAME AND NO.	LOCATION TOWN	LOCATION STATE	1994 STATUS	COMMENTS	LOCATION		UNIT TYPE	NOV. 1991 GOV. RPT. (2) CAPACITY (MW) NAMEPLATE	CLAIMED CAPABILITY-MW SUMMER CAPACITY	CLAIMED CAPABILITY-MW WINTER CAPACITY	FUEL TYPE	ALT FUEL TYPE
	01	02					03		04		05	06	07	09
C	BHE	Beaverwood Aed 1	Chester	ME	OP	DEACTIVATED RESERVE	23	019	ST	15.500	15.430	15.440	BIO	WD
C	CES	CPC Lowell (Joan Fabrics) [3]	Lowell	MA	OP	DEACTIVATED RESERVE	23	017	CC	26.800	28.800	24.000	NG	OIL
C	CMP	AEI Ashland (NE Beaver 1) [4]	Ashland	ME	OP	DEACTIVATED RESERVE	23	003	ST	N/L	32.600	32.600	WD	
C	NU	Alexandria Power	Alexandria	NH	OP	DEACTIVATED RESERVE	33	009	ST	16.800	15.000	15.000	WD	
C	NU	Timco Inc.	Center Barnstead	NH	OP	DEACTIVATED RESERVE	33	011	ST	4.800	3.850	3.800	WD	
N	NU	Rochester Wind	Rochester	NH	OP	DEACTIVATED RESERVE	33	017	WT	0.010	0.010	0.010	WND	
N	NU	Tourist Village Cogen	Gorham	NH	OP	DEACTIVATED RESERVE	33	007	IC	0.370	0.370	0.370	OIL	
N	NU	Velc o Cogen	Manchester	NH	OP	DEACTIVATED RESERVE	33	011	IC	2.400	2.400	2.400	OIL	
R	NU	Digital Corp Cogen	Nashua	NH	OP	DEACTIVATED RESERVE	33	011	ST	1.850	1.800	1.800	OIL	
R	NU	Digi'al Tara Cogen	Nashua	NH	OP	DEACTIVATED RESERVE	33	011	IC	0.000	0.000	0.000	OIL	
R	NU	Frank Yanco Cogen	Manchester	NH	OP	DEACTIVATED RESERVE	33	011	IC	0.280	0.300	0.300	OIL	
R	NU	Hull Forest Products	Pomfret	CT	OP	DEACTIVATED RESERVE	09	015	IC	0.680	0.680	0.680	OIL	
R	NU	Warren Woolen Mill	Stafford Springs	CT	OP	DEACTIVATED RESERVE	09	013	HY	0.200	0.050	0.050	WAT	

FOOTNOTES:

(1) C = CLAIMED FOR NEPOOL CAPABILITY; N = NETTED FROM LOAD; R = RETAINED BY FACILITY.
(2) SHOWN FOR INFORMATIONAL PURPOSES ONLY.
(3) IF NOT REACTIVATED BY JANUARY 1, 2001, THE CONTRACT WILL BE CANCELLED.
(4) LOCATED OUTSIDE THE NEPOOL SERVICE TERRITORY; TRANSFERRED OVER THE NEW BRUNSWICK TIE LINE.

SECTION XI - Non-Participant Generation Not Included as of January 1, 1997
XI.1 - Deactivated Reserve

TYPE (1)	SYSTEM 01	STATION NAME AND NO.	LOCATION TOWN	LOCATION STATE	STATUS	COMMENTS	LOCATION 04		UNIT TYPE	CLAIMED CAPABILITY - MW SUMMER CAPACITY 10	CLAIMED CAPABILITY - MW WINTER CAPACITY 11	FUEL TYPE 12	ALT FUEL TYPE 14
R	BHE	Beaverwood Aed 1	Chester	ME	OP-94	DEACTIVATED RESERVE	23	019	ST	2.10	2.10	BIO	WD
C	BHE	Beaverwood Aed 1	Chester	ME	OP-94	DEACTIVATED RESERVE	23	019	ST	15.43	15.44	BIO	WD
C	BHE	Ultrapower 5 (West Enfield)	West Enfield	ME	OP-95	DEACTIVATED RESERVE	23	019	ST	15.13	15.36	WD	
C	BHE	Ultrapower 6 (Jonesboro)	Jonesboro	ME	OP-95	DEACTIVATED RESERVE	23	029	ST	15.43	15.64	WD	
C	CES	CPC Lowell (Joan Fabrics) (2)	Lowell	MA	OP-94	DEACTIVATED RESERVE	23	017	CC	28.80	24.00	NG	OIL
C	CMP	AEI Ashland (NE Beaver 1) (3)	Ashland	ME	OP-94	DEACTIVATED RESERVE	23	003	ST	32.60	32.60	WD	
C	NU	Alexandria Power	Alexandria	NH	OP-94	DEACTIVATED RESERVE	33	009	ST	15.00	15.00	WD	
R	NU	Digital Corp Cogen	Nashua	NH	OP-94	DEACTIVATED RESERVE	33	011	ST	1.80	1.80	OIL	
R	NU	Digital Tara Cogen	Nashua	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	0.00	0.00	OIL	
R	NU	Frank Yanco Cogen	Manchester	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	0.30	0.30	OIL	
R	NU	Gilson Rd Hazardous Waste	Nashua	NH	OP-96	DEACTIVATED RESERVE	33	011	IC	0.18	0.18	REF	
R	NU	Hull Forest Products	Pomfret	CT	OP-94	DEACTIVATED RESERVE	09	015	IC	0.68	0.68	OIL	
N	NU	Rochester Wind	Rochester	NH	OP-94	DEACTIVATED RESERVE	33	017	WT	0.01	0.01	WND	
C	NU	Timco Inc.	Center Barnstead	NH	OP-94	DEACTIVATED RESERVE	33	011	ST	3.85	3.80	WD	
N	NU	Tourist Village Cogen	Gorham	NH	OP-94	DEACTIVATED RESERVE	33	007	IC	0.37	0.37	OIL	
N	NU	Velcro Cogen	Manchester	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	2.40	2.40	OIL	
R	NU	Warren Woolen Mill	Stafford Springs	CT	OP-94	DEACTIVATED RESERVE	09	013	HY	0.05	0.05	WAT	
C	UNITIL	Ultrapower 5 (West Enfield)	West Enfield	ME	OP-95	DEACTIVATED RESERVE	23	019	ST	9.50	9.50	WD	
C	UNITIL	Ultrapower 6 (Jonesboro)	Jonesboro	ME	OP-95	DEACTIVATED RESERVE	23	029	ST	9.50	9.50	WD	

FOOTNOTES:

(1) C = CLAIMED FOR NEPOOL CAPABILITY; N = NETTED FROM LOAD, R = RETAINED BY FACILITY

(2) IF NOT REACTIVATED BY JANUARY 1, 2001, THE CONTRACT WILL BE CANCELLED.

(3) LOCATED OUTSIDE THE NEPOOL SERVICE TERRITORY; TRANSFERRED OVER THE NEW BRUNSWICK TIE LINE.

SECTION XI - Non-Participant Generation Not Included as of January 1, 1998
XI.1 - Deactivated Reserve

TYPE (1)	SYSTEM 01	STATION NAME AND NO.	LOCATION TOWN	LOCATION STATE	STATUS	COMMENTS	LOCATION 06		UNIT TYPE	CLAIMED CAPABILITY - MW SUMMER CAPACITY 11	CLAIMED CAPABILITY - MW WINTER CAPACITY 12	FUEL TYPE 13	ALT FUEL TYPE 15
C	CES	CPC Lowell (Joan Fabrics) (2)	Lowell	MA	OP-94	DEACTIVATED RESERVE	23	017	CC	28.80	24.00	NG	OIL
C	CMP	AEI Ashland (NE Beaver 1) (3)	Ashland	ME	OP-94	DEACTIVATED RESERVE	23	003	ST	32.60	32.60	WD	
C	NU	Alexandria Power	Alexandria	NH	OP-94	DEACTIVATED RESERVE	33	009	ST	15.00	15.00	WD	
R	NU	Digital Corp Cogen	Nashua	NH	OP-94	DEACTIVATED RESERVE	33	011	ST	1.80	1.80	OIL	
R	NU	Digital Tara Cogen	Nashua	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	0.00	0.00	OIL	
R	NU	Frank Yanco Cogen	Manchester	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	0.30	0.30	OIL	
R	NU	Gilson Rd Hazardous Waste	Nashua	NH	OP-96	DEACTIVATED RESERVE	33	011	IC	0.18	0.18	REF	
R	NU	Hull Forest Products	Pomfret	CT	OP-94	DEACTIVATED RESERVE	09	015	IC	0.68	0.68	OIL	
N	NU	Rochester Wind	Rochester	NH	OP-94	DEACTIVATED RESERVE	33	017	WT	0.01	0.01	WND	
C	NU	Timco Inc.	Center Barnstead	NH	OP-94	DEACTIVATED RESERVE	33	011	ST	3.85	3.80	WD	
N	NU	Tourist Village Cogen	Gorham	NH	OP-94	DEACTIVATED RESERVE	33	007	IC	0.37	0.37	OIL	
N	NU	Velcro Cogen	Manchester	NH	OP-94	DEACTIVATED RESERVE	33	011	IC	2.40	2.40	OIL	
R	NU	Warren Woolen Mill	Stafford Springs	CT	OP-94	DEACTIVATED RESERVE	09	013	HY	0.05	0.05	WAT	

FOOTNOTES:

(1) C = CLAIMED FOR NEPOOL CAPABILITY; N = NETTED FROM LOAD, R = RETAINED BY FACILITY
(2) IF NOT REACTIVATED BY JANUARY 1, 2001, THE CONTRACT WILL BE CANCELLED.
(3) LOCATED OUTSIDE THE NEPOOL SERVICE TERRITORY; TRANSFERRED OVER THE NEW BRUNSWICK TIE LINE.

Exhibit 5

Indeck Energy-AlexandriaCapacity AdditionCapital Investments2007-2008

System	Description	Cost
Administration	Process Design, Project Management, Purchasing, Start-up/Training, Field/Shop Supervision, Field Labor, Travel & Perdiem, Equipment Rental,Freight, Tools & Consumables, Legal, Consulting/Technical	$ 1,284,406
Finance	Capitalized Interest Expense, Bank Legal	$ 39,425
Building and Grounds	Turbine Building/Office, Site Work/Grounds, HVAC, Air Compressor System, Fire Protection System	$ 136,390
Electrical Interconnect	Electrical Interconnect - Utility, Transformer/Backfeed Electrical	$ 481,295
Control System	Control System/Instrumentation	$ 383,999
Plant Electrical	Control Panel, Instrumentation and Control, Motor Control Centers, Terminations	$ 349,738
Water Supply / Waste Disposal	Water Supply, Sewer System/Septic, Potable Water System, Waste Disposal, River Water Makeup and Transfer Pumps, Additional Pumps	$ 154,952
Fuel System	Truck Dumps, Conveyor, Fuel Oil System, Truck Scale	$ 267,044
Boiler	Boiler Structure/Refractory, Fans and Ducting, Boiler Pressure Parts, Valves and Piping, Soot Blowers, Traveling Grate, Boiler Feed Pumps, Deaerator	$ 1,299,895
Emission Control System	Multiclone, Electrostatic Precipitator, Stack, Ammonia Injection and Storage, SNCR, Ammonia Scrubber	$ 1,360,324
Water Treatment	Water Treatment System	$ 166,457
Turbine / Generator System	Turbine / Generator System, Main Steam Line, Condensor, Air Ejector Vacuum Pump, Condensate Pumps/Piping/Valves, Cooling Tower, Circulation Water Pumps and Piping	$ 510,664
Emission Monitoring System	CEMS System	$ 263,851
Ash Handling System	Ash Wet Down, Bottom and Fly Ash Conveying, Fly Ash Reinjection, Ash Bunker	$ 171,467
Commissioning	Start-Up Iterations	$ 131,245
TOTAL		**$ 7,001,151**

INDECK ENERGY - ALEXANDRIA, LLC
2008 Project Cost

	Task Code	Cost	
Plant Labor	6090	6,058.25	
Internal Labor (except G&A, Acctg) thru April08	9010	175,689.16	
Travel Expense	9020	80,072.61	
Public Relations	9030	-	
Legal (Non Financial)	9040	17,398.46	
Professional/Consulting/Technical	9050	77,156.28	
Internal Labor (except G&A, Acctg) May08 onward	9110	245,626.44	
Travel Expense	9120	114,071.89	
Capitalized Interest Expense	9210	38,716.69	
General Contractor	10010	3,352,516.67	See Yanke Scope
Turbine Building/Office	10110	13,359.48	
Site Work, Grounds	10130	26,898.66	
HVAC	10140	19,828.80	
Air Compressor System	10150	24,247.69	
Fire Protection System	10160	12,101.83	
Stack	10170	2,127.96	
Other Building	10180	37,825.77	
Electrical Interconnect-Utility	10210	415,004.00	
Transformer/Backfeed Electrical	10220	66,290.78	
Control System/Instrumentation	10230	383,998.70	
Other/Plant Electrical	10240	176,538.10	
Water Supply	10310	85,416.28	
Sewer System/Septic	10320	13,331.77	
Potable Water System	10340	6,988.63	
Waste Disposal	10360	29,655.35	
Truck Dumps	10410	68,560.60	
Conveyor	10420	30,334.08	
Fuel Oil System	10430	55,204.27	
Other Fuel System	10440	112,944.86	
Boiler Structure, Refractory	10510	46.83	
Fans and Ducting	10520	517.71	
Boiler Pressure Parts	10530	9,024.54	
Valves and Piping	10540	66,051.21	
Soot Blowers	10550	2,428.49	
Traveling Grate	10560	88,585.22	
Boiler Feed Pumps	10570	89,210.58	
Deaerator	10580	3,228.00	
Other Boiler	10590	106,738.37	
Water Treatment	10610	166,456.50	
Turbine/Generator System	10710	389,923.93	
CEMS System	10910	263,851.43	
Ash Handling	10950	121,091.97	
Other Emission Control	10990	5,323.81	
Legal, Bank	11010	708.75	
		7,001,151.40	

Line Item	Cost Code		Yanke Scope
ADMINISTRATION			
PROCESS DESIGN	1001	$	10,000
PROJECT MANAGEMENT	1002	$	150,000
PURCHASING	1003	$	28,333
START UP/TRAINING	1004	$	116,000
FIELD /SHOP SUPERVISION	1005	$	25,000
PERMITS Air quality + transfer all	1006		
TRAVEL & PERDIEM	1007	$	78,000
EQUIPMENT RENTAL	1008	$	96,000
FREIGHT	1009	$	15,000
ACQUISITION COSTS	1010		
TOOLS CONSUMABLES	1011	$	50,000
UTILITIES			
SITE WORK, GRADING, PAVING	1101		
WATER SYSTEM FRESH WATER	1102		
River Water Makeup Pumps	1102	$	8,240
River Water Transfer Pumps	1102	$	9,000
Additional pumps	1102	$	2,320
SEWER SYSTEM	1103	$	-
TEMPORARY FACILITIES	1104	$	-
POTABLE WATER SYSTEM	1105	$	-
AIR COMPRESSOR SYSTEM	1106		
WASTE WATER SYSTEM	1107		
FIRE PROTECTION	1108		
BUILDINGS			
TURBINE BUILDING	1201		
FUEL ENCLOSURE	1202		
ELECTRICAL			
UTILITY INTERCONNECT	1301		
CONTROL PANEL	1302	$	20,000
SUBSTATIONS HIGH VOLTAGE AND STATION	1303		
INSTRUMENTATION AND CONTROL	1304	$	125,700
MOTOR CONTROL CENTERS	1305	$	7,500
GROUNDING	1306	$	-
CONDUIT & CABLE PULLING	1307	$	-
TERMINATIONS	1308	$	20,000
BATTERY POWER SYSTEM & UPS	1309		
ENVIROMENTAL CONTROLS	1310		
LIGHTING	1311	$	-
TELEPHONE , DEDICATED LINES, TELEMETRY	1312		
FUEL SYSTEM			
TRUCK DUMP #1	1401		
TRUCK DUMP #2	1402		
LIVE BOTTOM HOPPER MAIN	1403		
Live bottom Yard	1403		
LIVE BOTTOM HOPPER CONVEYOR	1404		
TRANSFER TOWER UPPER SCREEN	1405		
Fuel House Hammer Hog	1405		

Fuel House Hog Transfer #1	1405		
Fuel House Hog Transfer #2	1405		
RECLAIM CONVEYOR	1406		
DISC SCREEN	1407		
BOILER FEED CONVEYOR	1408		
METERING BINS	1409		
FUEL STOKERS	1410		
FUEL MAGNETS	1411		
TRAVELING GRATE			
GRATE	1601		
GRATE Drive	1602		
SIFTINGS HOPPER	1603		
BOTTOM ASH HOPPER	1604		
BOILER			
BOILER STRUCTURE, PRESSURE PARTS,REFR.	1701	$	100,000
SUPER HEAT TEMPERATURE	1701	$	250,000
AIR PRE HEATER	1702	$	10,000
F.D. FAN & DUCTING	1703	$	11,934
I. D. FAN AND DUCTING	1704	$	20,620
OVER FIRE AIR DUCTING AND CONTROLS	1705	$	390,000
VALVES AND PIPING	1706	$	40,000
HIGH PRESSURE ECONOMIZER	1707	$	10,000
SOOT BLOWERS	1708		
CHAR REINJECTION	1709		
OIL BURNER	1710		
BOILER SUPPORT			
BLOW DOWN SEPERATOR & HEAT EXCHANGER	1801	$	-
BOILER FEED PUMPS AND DRIVES	1802	$	98,910
Emergency piston pump	1802		
Feedwater control valve	1802	$	2,600
DEAREATOR	1803		
HIGH & LOW PRESSURE FEEDWATER HEATERS	1804		
BOILER FEED WATER TREATMENT	1805		
Boiler feedwater day tanks	1805		
TURBINE SYSTEM			
TURBINE	1901		
TURBINE GLAND EXHAUSTER	1901		
TURBINE OIL SYSTEM	1902		
TURBINE EXTRACTION SYSTEM	1903		
MAIN STEAM LINE	1904	$	20,000
CONDENSER	1905	$	16,000
AIR EJECTOR VACUUM PUMP	1906	$	11,000
CONDENSATE PUMPS AND PIPING	1907	$	12,680
Condensate control valves	1907	$	2,500
COOLING TOWER	1908	$	40,000
CIRCULATION WATER PUMPS AND PIPING	1909	$	18,560
COOLING TOWER WATER TREATMENT	1910		
GENERATOR			
GENERATOR	2001		

EXCITER	2002			
EMISSION CONTROL				
MULTICLONE	2101	$	110,000	
ELECTROSTATIC PRECIPITATOR	2102	$	450,000	
STACK	2103	$	5,000	
ASH HANDLING - Wet down	2104	$	3,800	
Fly ash reinjection		$	16,515	
Ash conveying, bottom and fly ash		$	30,060	
AMMONIA INJECTION AND STORAGE	2105	$	60,000	
SNCR	2106	$	400,000	
AMMONIA SCRUBBER	2107	$	330,000	
START-UP ITERATIONS				
START-UP ITERATIONS	xxxx	$	140,000	$ 131,245
TOTAL		$	**3,361,272**	**$ 3,352,517**

Exhibit 6

Exhibit 6

INDECK ENERGY-ALEXANDRIA, LLC

Annual Net Output (KWhs)

2008	1,363
2009	48,061
2010	98,121,331
2011	85,721,832
2012	105,115,739

GIS Certification #:
————

APPENDIX F
(Revised 6/11/10)
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. seq. 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 3.7) 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[5]; agricultural waste, food and vegetative material; energy crops; landfill methane[6] or biogas[7], 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.

[5] 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.

[6] 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.

[7] 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.

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).

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? ☑ Yes ❑ No ❑ N/A

Comments: **See Attachment F-1**

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 ☑ 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 ☑ N/A

Comments: ______________________________

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? ☑ Yes ❑ No ❑ N/A

Comments: **See Attachment F-4**

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.

☑ ← 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 ☑ 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. Specifically, RES Regulations Section 6.3(i) states that Renewable Energy Resources of the type that combust fuel to generate electricity must file quarterly reports due 60 days after the end of each quarter on the fuel stream used during the quarter. Instructions and filing documents for the quarterly reports can be found on the Commissions website or can be furnished upon request.

☑ ← 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? ☑ Yes ☐ No ☐ N/A

Comments: **See Attachment F-8.The Facility has applied for a further air permit from the New Hampshire Air Resources Division. The permit is pending and the Facility lawfully operates under the "permit shield" of the earlier permit until issuance of the new permit.**

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

02 / 04/ 08

F.10 State or jurisdiction issuing Valid Air Permit or equivalent authorization:
State of New Hampshire, Department of Environmental Services, Air Resources Division.

Attachment F

Indeck Energy-Alexandria, LLC RES Application
Appendix F Attachments

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

The Alexandria Facility will use for a fuel source processed wood fuels as Eligible Biomass Fuels including materials such as tree chips, brush, tops, limbs and thinnings, stump grindings and sawmill board end 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. Over 90% of the virgin wood fiber comes directly from the forest predominantly from a 25 mile radius surrounding the Alexandria Facility.

Most of the wood fuel will be chips that are processed at the location where the trees are cut down as part of a commercial timber harvest, silviculture improvement process or from projects where forest is cleared for development. Chips from forest operations make up near 100% of the fuel supply for the Alexandria Facility at this time. The majority of biomass is softwood (60-70%) with the remainder coming from various hardwood species.

Fine saw mill residues, 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 Alexandria Facility purchases little fine sawmill residue under to its fuel procurement plan.

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. See F-4.

F.2 If Fuel is "other clean wood": Not Applicable.

F. 3 Co-Firing with ineligible fuels: Not Applicable.

F.4 The Fuel Source Plan

Alexandria is counterparty to a Fuel Supply Agreement with a forest products company and its staff of NH certified foresters acting as agent in ensuring delivery of exclusively clean processed wood fuels. The Facility staff visually inspects each load and has a scale and recording procedure for incoming wood fuel deliveries. The recording procedures include the party that 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. Wood chip moisture content is measured each day. Pursuant to the terms of the Fuel Supply Agreement, loads can be rejected with prompt notification to the contracted supply agent, based on the wood fuel quality characteristics noted below:

- Fuel must be free of contaminants including dirt, rocks, plastics, metal, paint, stain, varnish, glue, resin and other chemicals. Ground construction and demolition debris are not accepted.

It is the seller's responsibility to remove non-complying fuel from the Facility premises.

F.5 Acknowledgement that fuels stored or brought are Eligible Biomass Fuels:

As part of the fuel source plan in F-4, the applicant acknowledges that the fuel stored at or brought to the Generation unit for combustion 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.

F.6 Documentation of recycled wood waste: Not Applicable.

F.7 Certification:

The applicant certifies that it will file all reports and other information necessary to enable the Commission to verify the on-going eligibility of the renewable energy generator pursuant to Section 6.3 of the RES Regulations.

F.8 Air Permit: See attachment F-8 for the generation unit's New Hampshire air permit.

F.9 Air Permit effective date: Feb. 4, 2008.

F.10 Jurisdiction issuing Air Permit: New Hampshire (Department of Environmental Services, Air Resources Division).

Attachment F-8
(NH Air Permit)

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
	<u>*Quarterly Excess Emissions Report (continued)*</u> 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.