ATTACHMENTS

Attachment A	NPT Certificate of Formation
Attachment B	2015 NPT Annual Report to the New Hampshire Secretary of State
Attachment C	NPT Officers
Attachment D	Eversource Organizational Chart
Attachment E	FERC Order Granting Petition for Declaratory Order
Attachment F	FERC Order Accepting Transmission Service Agreement
Attachment G	Transmission Service Agreement
Attachment H	Eversource Energy 2014 Form 10-K Annual Report
Attachment I	Ausere Testimony
Attachment J	Fortier Testimony
Attachment K	Docket DE 03-186, Settlement Agreement, April 16, 2004

Filed
Date Filed: 03/31/2010
Business ID: 628647
William M. Gardner
Secretary of State

STATE OF NEW HAMPSHIRE

Form LLC-1
RSA 304-C:12

CERTIFICATE OF FORMATION
NEW HAMPSHIRE LIMITED LIABILITY COMPANY

THE UNDERSIGNED, UNDER THE NEW HAMPSHIRE LIMITED LIABILITY COMPANY LAWS SUBMITS THE FOLLOWING CERTIFICATE OF FORMATION:

FIRST: The name of the limited liability company is **Northern Pass Transmission LLC**.

SECOND: The nature of the primary business or purposes are:

1. Designing, acquiring, constructing, owning and operating certain transmission facilities and related property and equipment;
2. Conducting any and all activities normally exercised by an owner and operator of property in relation or incidental to the business conducted or property held by the Company; and
3. Conducting any other lawful business, purpose or activity in which a limited liability company may be engaged under applicable law.

THIRD: The name of the limited liability company's registered agent is C T Corporation System and the street address, town/city (including zip code and post office box, if any) of its registered office is 9 Capitol Street, Concord, New Hampshire, 03301.

FOURTH: The limited liability company shall have perpetual existence.

FIFTH: The management of the limited liability company is not vested in a manager or managers.

SIXTH: The sale or offer for sale of any ownership interests in this business will comply with the requirements of the New Hampshire Uniform Securities Act (RSA 421-B).

Effective 3/31/10 @ 12:07 p.m.

NU TRANSMISSION VENTURES, INC.
MEMBER

March 30, 2010

By: Charles W Shivery
Charles W. Shivery
Chairman, President and Chief Executive Officer

State of New Hampshire
Form LLC 1 - Certificate of Formation 3 Page(s)
T1009031012
012

Form SRA – Addendum to Business Organization and Registration Forms
Statement of Compliance with New Hampshire Securities Laws

Part I – Business Identification and Contact Information

Business Name: Northern Pass Transmission LLC

Business Address (include city, state, zip): Energy Park, 780 North Commercial Street, Manchester, New Hampshire, 03101.

Telephone Number: (603) 669-40000 E-mail: comenok@nu.com

Contact Person: O. Kay Comendul

Contact Person Address (if different): c/o Northeast Utilities Service Company
P.O. Box 270, Hartford, CT 06141

Part II – Check ONE of the following items in Part II. If more than one item is checked, the form will be rejected. [***PLEASE NOTE***: Most small businesses registering in New Hampshire qualify for the exemption in Part II, Item 1 below. ***However***, you must insure that your business meets all of the requirements spelled out in A), B), and C)]:

1. XX Ownership interests in this business are exempt from the registration requirements of the state of New Hampshire because the business meets ALL of the following three requirements:
   A) This business has 10 or fewer owners; and
   B) Advertising relating to the sale of ownership interests has not been circulated; and
   C) Sales of ownership interests – if any – will be completed within 60 days of the formation of this business.
2. ____ This business will offer securities in New Hampshire under another exemption from registration or will notice file for federal covered securities. Enter the citation for the exemption or notice filing claimed - ________________.
3. ____ This business has registered or will register its securities for sale in New Hampshire. Enter the date the registration statement was or will be filed with the Bureau of Securities Regulation - ____________.
4. ____ This business was formed in a state other than New Hampshire and will not offer or sell securities in New Hampshire.

Part III – Check ONE of the following items in Part III:

1. ____ This business ***is not being*** formed in New Hampshire.
2. XX This business ***is*** being formed in New Hampshire and the registration document states that any sale or offer for sale of ownership interests in the business will comply with the requirements of the New Hampshire Uniform Securities Act.

Part IV – Certification of Accuracy

(NOTE: The information in Part IV must be certified by: 1) all of the incorporators of a corporation to be formed; or 2) an executive officer of an existing corporation; or 3) all of the general partners or intended general partners of a limited partnership; or 4) one or more authorized members or managers of a limited liability company; or 5) one or more authorized partners of a registered limited liability partnership or foreign registered limited liability partnership.)

NU Transmission Ventures, Inc. certifies that the information provided in this form is true and complete. (Original signatures only)

NU TRANSMISSION VENTURES, INC.
MEMBER

March 30, 2010

By: Charles W. Shivery
Charles W. Shivery
Chairman, President and Chief Executive Officer

State of New Hampshire
Department of State
2015 ANNUAL REPORT

Filed
Date Filed: 3/30/2015
Effective Date: 3/30/2015
Business ID: 628647
William M. Gardner
Secretary of State

BUSINESS NAME:	**NORTHERN PASS TRANSMISSION LLC**
BUSINESS TYPE:	**Domestic Limited Liability Company**
BUSINESS ID:	**628647**
CITIZENSHIP:	**Domestic**
STATE OF FORMATION:	**New Hampshire**

PREVIOUS PRINCIPAL OFFICE ADDRESS	PREVIOUS MAILING ADDRESS
Energy Park780 North Commercial Street Manchester, NH, 03101, USA	**Kay ComendulNortheast Utilities Service CompanyP.O. Box 270 Hartford, CT, 06141, USA**

NEW PRINCIPAL OFFICE ADDRESS	NEW MAILING ADDRESS
780 North Commercial Street Manchester, NH, 03101, USA	**Kay Comendul PO Box 270 Hartford, CT, 06141, USA**

REGISTERED AGENT AND OFFICE	
REGISTERED AGENT:	**C T Corporation System**
REGISTERED AGENT OFFICE ADDRESS:	**9 Capitol Street Concord, NH, 03301, USA**

PRINCIPAL PURPOSE(S)	
NAICS CODE	NAICS SUB CODE
OTHER / operating certain transmission facilites and related property equipment	

MANAGER / MEMBER INFORMATION		
NAME	BUSINESS ADDRESS	TITLE
Leon J Olivier	**107 Selden Street, Berlin, CT, 06037, USA**	**Member**
James J Judge	**800 Boylston Street, Boston, MA, 02199, USA**	**Member**

I, the undersigned, do hereby certify that the statements on this report are true to the best of my information, knowledge and belief.

Richard J Morrison	**Authorized Party**
SIGNATURE	TITLE

NORTHERN PASS TRANSMISSION LLC

SOLE MEMBER

Eversource Energy Transmission Ventures, Inc. (a wholly-owned subsidiary of Eversource Energy)		107 Selden Street, Berlin, CT 06037

MEMBERS COMMITTEE

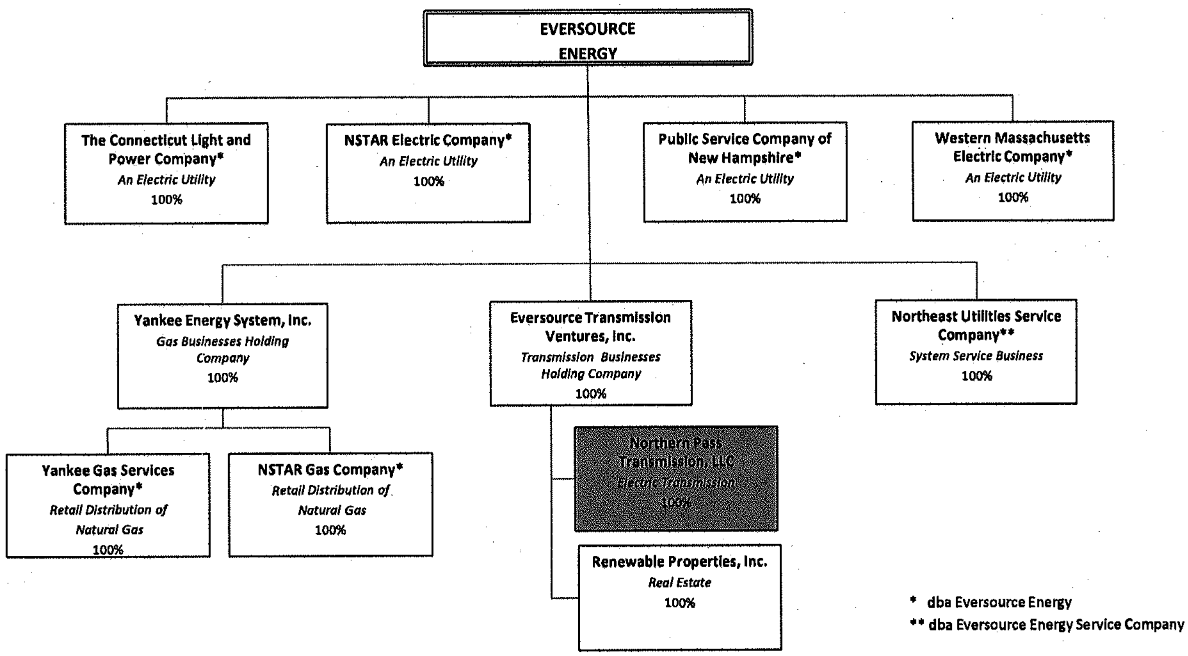
	James J. Judge	800 Boylston Street, Boston, MA 02199
	Leon J. Olivier	56 Prospect Street, Hartford, CT 06103

OFFICERS

Chairman of the Members Committee	Leon J. Olivier	56 Prospect Street, Hartford, CT 06103
President	James A. Muntz	56 Prospect Street, Hartford, CT 06103
Executive Vice President and Chief Financial Officer	James J. Judge	800 Boylston Street, Boston, MA 02199
Senior Vice President and General Counsel	Gregory B. Butler	56 Prospect Street, Hartford, CT 06103
Vice President, Controller and Chief Accounting Officer	Jay S. Buth	107 Selden Street, Berlin, CT 06037
Vice President and Treasurer	Philip J. Lembo	One NSTAR Way, Westwood, MA 02090
Secretary	Richard J. Morrison	800 Boylston Street, Boston, MA 02199

As of October 9, 2015

EVERSOURCE ENERGY CORPORATE CHART
OF MAJOR SUBSIDIARIES
EFFECTIVE APRIL 30, 2015



127 FERC ¶ 61,179
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Northeast Utilities Service Company and NSTAR Electric Company — Docket No. EL09-20-000

ORDER GRANTING PETITION FOR DECLARATORY ORDER

(Issued May 22, 2009)

1. On December 12, 2008, Northeast Utilities Service Company (Northeast) and NSTAR Electric Company (NSTAR) (collectively, Petitioners) filed a request for the Commission to issue a declaratory order approving the structure of a transaction involving a cost-based participant funded transmission project (Project) that includes a long-term bilateral transmission service agreement (Transmission Service Agreement) between H.Q. Energy Services (U.S.) Inc. (HQUS)[1] and the Petitioners. For the reasons discussed below, we grant the petition.

I. Petition

2. Hydro-Québec is currently developing over 4,000 MW of new hydro-electric generation in the Province of Québec. This expansion will make significant amounts of surplus hydro-electric power available for export to the United States. The Petitioners and Hydro-Québec TransÉnergie (HQ TransÉnergie) are currently negotiating a joint development agreement for the design, planning and construction of a 1,200 MW high voltage direct current (HVDC) transmission line that will connect Hydro-Québec's system to a yet undetermined point in Southern New Hampshire so the power can be delivered into the backbone of the 345 kV transmission system controlled by ISO New England, Inc. (ISO-NE). Petitioners state that no other entity has expressed interest in the

[1] HQUS is a wholly-owned subsidiary of Hydro-Québec which is a Crown corporation that is wholly-owned by the Government of Québec.

Project[2] comparable to HQUS'. Petitioners have not indicated whether the Project will include ancillary services.

3. HQ TransÉnergie will construct, finance and own the Canadian portion of the transmission line and the Petitioners will construct, finance and own the portion of the line located in the U.S. The Petitioners will submit the transmission line for ISO-NE section I.3.9 reliability approval to ensure that the transmission line will not adversely affect the reliability or use of the New England transmission system. Further, the Petitioners intend to transfer to ISO-NE operational control of the U.S. portion of the transmission line pursuant to a Transmission Operating Agreement (TOA) to be negotiated with ISO-NE. Under the TOA, ISO-NE will have final authority over planned line outages and will schedule all transactions over the transmission line in accordance with ISO-NE's market rules.

4. According to the Petitioners, the 1,200 MW of firm transmission rights acquired by HQUS under the Transmission Service Agreement will be at negotiated rates capped at a cost-based rate, including a reasonable return on the Petitioners' invested capital.[3] Once executed, the Transmission Service Agreement will be filed with the Commission pursuant to section 205 of the FPA and will be subject to a Commission approved cost-based rate ceiling.[4] Further, the Petitioners state that, because the transmission line is participant funded by HQUS, it will not be included in the rates for transmission service under ISO-NE's Open Access Transmission Tariff (OATT).

5. The Petitioners state that depending on market interest and transfer capabilities, an additional 200 MW of incremental capacity may be made available through an open season under the same rate, terms and conditions as provided for in the Transmission Service Agreement with HQUS. The Petitioners add that the line could be larger than 1,400 MW if ISO-NE were to determine that the firm available transfer capability of the

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[2] Petition at 10. Petitioners state that one entity expressed interest for capacity on the Project for 5 years, but Petitioners considered this speculative because additional investors would be needed for the remaining 15 years, and Petitioners state that they are not willing to go forward with the transaction on that basis. (Petition at n.14.).

[3] HQUS will compensate the Petitioners for constructing, operating, and maintaining the U.S. portion of the transmission line in return for 1,200 MW of firm transmission rights.

[4] The Petitioners state that the transmission line is not intended to be a "merchant" transmission line because they will not seek market-based rate authorization for the services provided over the proposed line.

project line could be higher. If so, they will size the line to the maximum firm available transfer capability that is supported by the marketplace as determined in the open season.[5] The Petitioners intend to solicit comments from interested parties regarding the 200 MW of incremental capacity and will file the details of the proposed open season for Commission approval at the same time that the Transmission Service Agreement is filed. The Petitioners also intend to make any transmission capacity that is not used by HQUS available on an open access basis and commit to making the transmission service available at rates, terms and conditions consistent with Order No. 890.[6]

6. In addition to the Transmission Service Agreement and the joint development agreement, the Petitioners and HQUS are also negotiating a power purchase agreement under which HQUS will sell 1,200 MW of firm power to Petitioners and other interested New England entities for a period of no less than twenty years under HQUS' market-based rate tariff, which is on file with the Commission.[7] The Petitioners claim that HQUS will recover the cost of transmission rights it acquires under the Transmission Service Agreement through the price of power sold under the power purchase agreement and that both agreements are related and should be considered as part of a combined energy and transmission transaction. The Petitioners and HQUS intend that the power sold under the power purchase agreement will be made broadly available to load in New England and that any potential buyers will have at least a twenty-year purchase commitment and must meet reasonable credit requirements. The Petitioners state that they must demonstrate to New England state regulatory authorities that the power purchase agreement represents a fair deal for New England electric customers in order for the transaction to go forward.

7. The Petitioners also anticipate that the term of the power purchase agreement with HQUS will be between 20 and 25 years. However, HQUS will likely be paying for its

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[5] Petition at n.13.

[6] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890), *order on reh'g,* Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (Order No. 890-A), *order on reh'g and clarification,* Order No. 890-B, 123 FERC ¶ 61,299 (2008), (Order No. 890-B) *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228 (2009) (collectively, Order No. 890).

[7] HQUS was authorized by the Commission to make market-based sales in Docket Nos. ER97-851-000 and ER97-851-001. *H.Q. Energy Servs. (U.S.) Inc.,* 81 FERC ¶ 61,184 (1997), *reh'g denied,* 82 FERC ¶ 61,234 (1998); *H.Q. Energy Servs. (U.S.) Inc.,* 79 FERC ¶ 61,152 (1997).

transmission capacity rights based on an amortization period of up to 40 years which reflects the anticipated life of the transmission line. Therefore, the Petitioners argue that because HQUS will continue to participant fund the transmission line after the power purchase agreement terminates, HQUS will continue to have the same rights to schedule power over the transmission line after the power purchase agreement terminates.

8. The Petitioners assert that the Project offers several significant benefits to New England and its customers. The Project's anticipated 1,200 MW of low-cost hydro-electric power should help reduce dependence on fossil fuels, increase fuel diversity, and minimize price volatility in New England. The Petitioners argue that to the extent the Project displaces gas-fired generation in New England, greenhouse gas emissions associated with producing electricity will be reduced by an estimated four to six million tons of CO_2 per year during the term of the transaction which will assist in meeting regional environmental goals. The Petitioners assert that the additional power will likely reduce the Locational Marginal Price (LMP) of energy in New England at a time when electricity prices in the region are rising. Finally, Petitioners claim that because the Project will be participant funded, the New England transmission system will be expanded without raising regional transmission rates under ISO-NE's OATT or creating disputes over cost allocation of the Project transmission line.

9. Petitioners argue that its proposal conforms to Commission precedent including Order Nos. 888 and 890 and the Commission Standards of Conduct, Order No. 2004.[8] Petitioners state that in the 1980s most of New England's utilities entered into two long-term firm energy transactions with Hydro-Québec in connection with the development of the Hydro-Québec Phase I and Phase II HVDC tie lines.[9] Petitioners contend that while

[8] *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs. ¶ 31,155 (2003), *order on reh'g*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31,161, *order on reh'g*, Order No. 2004-B, FERC Stats. & Regs. ¶ 31,166, *order on reh'g*, Order No. 2004-C, FERC Stats. & Regs. ¶ 31,172 (2004), *order on reh'g*, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *vacated and remanded as it applies to natural gas pipelines sub nom. National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006); *see Standards of Conduct for Transmission Providers*, Order No. 690, FERC Stats. & Regs. ¶ 31,237, *order on reh'g*, Order No. 690-A, FERC Stats. & Regs. ¶ 31,243 (2007); *see also Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,611 (2007); Notice of Proposed Rulemaking, 73 Fed. Reg. 16,228 (Mar. 27, 2008), FERC Stats. & Regs. ¶ 32,630 (2008) (collectively Order No. 2004).

[9] *See* ISO-NE Transmission, Markets & Services Tariff, section II – OATT, schedule 20A, section 1.2.

that proposal was completed prior to Order Nos. 888 and 890, they assert that the Commission has recognized the benefits from the coordinated development of power supply and transmission planning. For example, Petitioners contend that this Project is similar to generator lead line projects whereby the Commission has approved allocating the transmission rights to generators who pay for the line. Petitioners argue similarities with this Project because it will be connecting the Hydro-Québec system with ISO-NE.

II. Notice

10. Notice of Petitioners' filing was published in the *Federal Register*, 73 Fed. Reg. 79,078 (2008), with interventions and protests due on or before January 12, 2009. On December 19, 2008 New England Independent Transmission Company (New England ITC) filed a motion to extend the comment period to January 26, 2009. On January 8, 2009, the Commission granted the motion. Thirty two entities filed motions to intervene.[10]

11. The following entities filed motions to intervene and protests: Nalcor Energy; Newfoundland and Labrador Hydro; the NRG Companies; Competitive Suppliers;[11] Iberdrola Renewables, Inc.(Iberdrola Renewables); Dynegy Power Marketing, Inc.

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[10] HQ Energy; Calpine Corporation; TransCanada Power Marketing, Ltd.; Bangor Hydro-Electric Company; First Wind Energy, LLC; Vermont Transco LLC; Dominion Resources Services, Inc.; IRH Management Committee; Boston Generating, LLC; Mystic I, LLC; Mystic Development, LLC; Fore River Development, LLC; Central Maine Power Company; New Brunswick Power Generation; Consolidated Edison Solutions Inc. and Consolidated Edison Energy, Inc.; Retail Energy Supply Association; New England Power Pool; Mirant Energy Trading, LLC; Mirant Canal, LLC; Mirant Kendall, LLC; North American Energy Alliance, LLC; Brick Power Holdings, LLC; Vermont Public Power Supply Authority; the NRG Companies including: NRG Power Marketing LLC, Connecticut Jet Power LLC. Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC; Constellation Energy Commodities Group, Inc.; Constellation NewEnergy, Inc.; NextEra Energy Resources, LLC; New Hampshire Electric Cooperative, Inc.; Connecticut Municipal Electric Energy Cooperative; Massachusetts Municipal Wholesale Electric Company; and Energy Management, Inc.

[11] Competitive Suppliers include Electric Power Supply Association, the New England Power Generators Association, Inc., and the Independent Energy Producers of Maine.

(Dynegy); Casco Bay Energy Company (Casco Bay); Bridgeport Energy, LLC; and Indicated New England Generators (Indicated NE Generators).[12]

12. These companies and public entities filed motions to intervene and comment: Cargill Power Markets, Inc. (Cargill); Green Mountain Power Corporation (Green Mountain); New England ITC; Brookfield Energy Marketing Inc. (Brookfield); The United Illuminating Company (United Illuminating); Vermont Department of Public Service; ISO-NE; National Grid USA (National Grid); Connecticut Office of Consumer Counsel; Transmission Developers, Inc. (Transmission Developers); Ridgewood Renewable Power LLC (Ridgewood Renewable); PSEG Companies(PSEG);[13] Direct Energy Services, LLC; and Central Vermont Public Service Corporation (Central Vermont).

13. Notices of intervention were filed by: Maine Public Utilities Commission, Connecticut Department of Public Utility Control (Connecticut PUC), Massachusetts Department of Public Utilities, and the New Hampshire Public Utilities. The Massachusetts Attorney General filed a late notice of intervention, Vermont Transco filed motion to submit comments out-of-time. Pacific Gas and Electric Company, SUEZ Energy Marketing NA, Inc., FirstLight Power Resources Management, LLC, and Cape Light Compact filed late motions to intervene.

14. The Petitioners and HQUS filed answers to the protests and comments. Four entities filed responses to these answers: New England Generators, New England ITC, the Competitive Suppliers and United Illuminating. The Petitioners filed a response to these four answers. The protests, comments and answers are discussed below.

III. Discussion

A. Procedural Matters

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2008) the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2008), the Commission will grant the late-filed motions to intervene, given the movants'

[12] Indicated New England Generators include NextEra Energy Resources, LLC, Mirant Energy Trading, LLC, Mirant Canal, LLC, Mirant Kendall, LLC and TransCanada Power Marketing Ltd.

[13] The PSEG Companies include Public Service Electric and Gas Company, PSEG Power LLC, PSEG Energy Resources & Trade LLC.

interest in the proceeding, the early state of the proceeding and the absence of undue prejudice or delay.

16. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits an answer to a protest and answer, unless otherwise ordered by decisional authority. We will accept the answers of the Petitioners, HQUS, New England Generators, New England ITC, the Competitive Suppliers and United Illuminating because they have provided information that assisted us in our decision-making process.

B. Summary Findings

17. As discussed below, we approve the proposed structure of the transaction, with the caveat that we will independently review the Transmission Service Agreement and the TOA, and any other jurisdictional rate schedules, when they are submitted to the Commission. We find that Petitioners have adequately addressed protesters' concerns as to whether Petitioners' proposal will result in undue discrimination or is otherwise unjust and unreasonable. We are granting Petitioners' request subject to the Commission finding that the rates, terms and conditions included in the executed Transmission Service Agreement are just, reasonable and not unduly discriminatory or preferential when it is filed with the Commission.[14]

1. Order No. 890 Issues

a. Protests and Comment

18. Ridgewood Renewable argues that the "underlying approach" of the proposal is that if a company wants to construct and pay for its own private transmission line, the Commission should approve it because new transmission capacity "is always a good thing."[15] It also contends that Commission policy does not provide that because a transmission line is privately funded the line is exempt from Order No. 890[16] and other policies aimed at promoting competition and access to transmission facilities.

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[14] As with any cost-based rate, Petitioners must include the necessary detail to support its cost basis for establishing the cost-based ceiling it has proposed. *See* 18 C.F.R. § 35.13 (2008).

[15] Ridgewood Renewable Preliminary Comments at 5.

[16] *See supra* n.6.

19. United Illuminating agrees with Petitioners that in Order Nos. 717[17] and 890 the Commission recognized the importance of coordinated resource planning. However, United Illuminating contends that the Commission stressed the importance of coordinated resource planning in Order Nos. 717 and 890 to ensure open and non-discriminatory access to transmission facilities. They argue that Petitioners misapply the Commission's emphasis on coordinated resource planning to justify closing access to the proposed HQ-New Hampshire Line to all potential customers but HQUS. Moreover, because only HQUS would have access to the Project for the next twenty years, the proposal is preferential and unduly discriminatory. United Illuminating states that the policy implications of the proposal are so significant that, if the Commission chooses to approve this Project, it should do so through a rulemaking proceeding.[18]

20. Several protesters contend that Petitioners have not sufficiently supported their proposal to circumvent the Commission's Order No. 890 open season requirement. For example, Brookfield states that Petitioners' proposal for a cost-based price ceiling for transmission service is not sufficient justification to avoid an open season. Brookfield argues that the Project violates Order No. 890's policy of providing all interested parties equal opportunity to compete for open access to transmission. Further, Brookfield states that Petitioners failed to address other similar transmission projects that included open seasons in their proposals.[19] Cargill states that, given the high demand for transmission service from Québec into ISO-NE, the Petitioners have not given sufficient explanation as to why only a small portion of the line would be available for an open season. Cargill asserts that the Commission should require the Petitioners to build the additional 200 MW of capacity and to offer a greater percentage of the transmission line's 1,200 MW of capacity in an open season.

21. Competitive Suppliers, with the support of Dynegy, Casco Bay, and Bridgeport, assert that an open season must be employed initially to allocate transmission rights on the Project. They argue that the Commission has addressed the rights that accrue to parties that accept responsibilities for funding a new transmission line.[20] Competitive

[17] *Standards of Conduct for Transmission Providers*, Order No. 717, 73 Fed. Reg. 63,796 (October 27, 1980), FERC Stats. & Regs. ¶ 31,280 (2008) (Order No. 717).

[18] United Illuminating Comments at 18.

[19] Brookfield Comments at 12, referring specifically to the open seasons proposed for Cross Sound Cable, Seabreeze, Neptune, Montana-Alberta Tie Line, VFT, Chinook, and Zephyr projects.

[20] Citing *Cross Hudson LLC,* 123 FERC ¶ 61,001 (2008). (*Cross Hudson*)

Suppliers point to an inconsistency in the Petitioners' request for waiver of the Commission's open access regulations and their acknowledgement that one of the Petitioners already has received an expression of interest in acquiring capacity rights on the Project from a potential suppler other than HQUS.[21] Competitive Suppliers assert that the proposal is inconsistent with the Commission's waiver policy, which provides that waivers are only granted until a third party requests access.

22. PSEG also agrees that an open season should be conducted, arguing that the failure to do so contradicts the Commission's Order Nos. 888, 890, and 717, as well as the interconnection provisions of section 202(b) of the FPA.[22] Additionally, PSEG asserts that the Commission has previously restricted waivers of Order Nos. 888 and 890 to transmission facilities that are not part of an integrated network and have not yet received a transmission request. PSEG argues that Petitioners fail to qualify for a waiver on both counts because the Project will be interconnected with and integrated into ISO-NE, and the Project will provide HQUS with interstate transmission service over the line.

23. New England ITC asserts the Petitioners' claim that the Project is participant funded does not alter the need for compliance with the Commission's open access requirements. New England ITC argues that in some respects the Petitioners' proposal resembles a participant-funded network upgrade and that the Petitioners without any justification, seek to redefine the rights to which they would be entitled if they participant fund the Project. New England ITC argues that the Commission has substantial precedents that identify financial transmission rights as the reward to parties who participant-fund network upgrades, and that the allocation of financial transmission rights preclude exclusive rights to use the line and the project is subject to open access.[23]

24. ISO-NE supports the proposed transaction and asserts that Order No. 890 appears to have contemplated this type of arrangement.[24] Moreover, ISO-NE states that the

[21] See n.14 of the Petition.

[22] 16 U.S.C. 824(a) (2008).

[23] New England ITC Comments at 13, citing *Cleco Power LLC*, 103 ¶ 61,272, at P 52 (2003).

[24] ISO-NE Comments at 5 citing Order No. 890 at PP 543-544 (encouraging the development of 'upgrades and other investments that could reduce congestion or integrate resources') and P 557 ("Transmission Provider and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.").

proposed transaction is consistent with principles espoused by many New England stakeholders.

b. Answer

25. The Petitioners state that their proposal is based on a different paradigm than the typical transmission transaction under Order No. 890 and that it is not inconsistent with the Commission's open access transmission policy. The Petitioners argue that the transmission line will be participant funded and the Commission's policy permits dedicated transmission rights for such projects.[25] The Petitioners contend that the Project is consistent with the *pro forma* OATT policy of making transmission capacity available on a first-come, first-served basis and is consistent with the Commission's functional unbundling requirement, because the agreements and rates for transmission and generation will be distinct and separately stated. The Petitioners state that they do not have vertical market power because they will transfer operating control to ISO-NE, which will operate the system in accordance with Order No. 890, including any requirement to expand their transmission system if directed by ISO-NE to do so.

26. With regard to United Illuminating's request for a rulemaking proceeding, the Petitioners argue that such a rulemaking proceeding is unnecessary because they are not asking the Commission to establish any new rules of general applicability. Petitioners also maintain that they do not understand United Illuminating's opposition to their proposal, because United Illuminating will not be responsible for any costs of the line or power sold under the power purchase agreement unless it so chooses.[26]

c. Commission Determination

27. We disagree with the protesters' claim that Petitioners' proposal contravenes the Commission's open access requirements in Order Nos. 888 and 890 and is anticompetitive because all of the available capacity on the line has been allocated

[25] Petitioners Answer at 14, citing *Regional Transmission Organizations*, 96 FERC ¶ 63,036, at 65,190 (2001) (noting that there may be participant funded facilities constructed in a regional transmission organization that are directly funded by a participant in return for the associated long-term transmission rights); *ISO New England, Inc.*, 109 FERC ¶ 61,252, at P2 (2004) ("If…new transmission facilities are built to benefit particular participants or groups of participants, participant funding – *i.e.* allocation of the costs to that participant or participants – is appropriate for those projects."

[26] Petitioners' Answer at 22.

exclusively to HQUS without an open season for others to compete. Providing for participant funding of a transmission facility with priority rights to use that facility is fully consistent with long-standing open access policies.[27] The transaction between a transmission customer (HQUS) and Petitioners under which HQUS has agreed to pay 100 percent of the costs for a system expansion in return for usage rights to the new HVDC transmission line does not constitute undue discrimination or preference. Any potential transmission customer has the right to request transmission service expansion from a transmission owning utility and that utility is obligated to make any necessary system expansions and offer service at the higher of an incremental cost or an embedded cost rate to the transmission customer. The fact that the Petitioners have turned over operational control of its existing transmission facilities to ISO-NE, does not relieve the Petitioners of their residual obligations under Order No. 888 to expand its system upon request.[28]

28. Moreover, with regard to the system expansion at issue in this case, Petitioners indicate that they are willing to conduct an open season for an additional 200 MW of incremental capacity on the line under the same terms and conditions agreed to by HQUS, subject to a finding by ISO-NE that this additional capacity will not adversely affect reliability in the region. Petitioners indicate that to date no other entity has

[27] *See Entergy Services, Inc.*, 115 FERC ¶ 61,095 (2006), *order on reh'g*, 116 FERC ¶ 61,275 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,013 (2007), *order on reh'g and compliance filing*, 119 FERC ¶ 61,187 (2007), *order on reh'g and clarification*, 122 FERC ¶ 61,216 (2008); *Western Area Power Administration*, 99 FERC ¶ 61,306, *reh'g denied*, 100 FERC ¶ 61,331 (2002), *aff'd sub nom. Public Utilities Comm'n of the State of CA v. FERC* 361 U.S. App. D.C. 302, 367 F.3d 925 (D.C. Cir. 2004) (Western); (approves a transmission project that grants exclusive transmission rights to the funders and no obligation of expansion); *Transbay Cable LLC*, 112 FERC ¶ 61,095, (2005) *order on reh'g* 114 FERC ¶61,031 (2006) (Transbay) (awarding of rights for transmission funding of line); *see generally Aero Energy, LLC*, 115 FERC ¶ 61,128 (2006) (initially awarded transmission rights to party who funded the line).

[28] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

expressed a willingness to participate in the Project at the same terms and conditions agreed to by HQUS. Petitioners further assert that they intend to make available any Project capacity not being used by HQUS consistent with the *pro forma* OATT requirements. The Petitioners and HQUS state that, if ISO-NE were to determine that the firm available transfer capability of the Project could be greater than 1,400 MWs, they commit to size the line at the maximum firm available transfer capability that is supported by the marketplace as determined by an open season.[29] Petitioners conclude that they will provide the details of the open season in their Transmission Service Agreement filing.[30]

29. Although we are accepting Petitioners' offer to conduct an open season in the event that ISO-NE determines that the Project should be expanded beyond 1,200 MWs, we disagree with Protesters' claims that an open season is required with regard to cost-based, participant-funded transmission system expansions, such as the one at issue in this proceeding. The Commission has imposed open season requirements when a merchant transmission project developer has proposed providing transmission access at negotiated rates as a way to ensure against undue discrimination, but this is not a merchant project as discussed more fully below. In this case, the transmission expansion project requested by HQUS will be an HVDC line from Canada at a cost-based rate that will require Commission approval in a subsequent section 205 rate filing. Any other potential developer has the same right to request transmission service necessary to interconnect new generation resources to the Petitioners' systems. Under Order No. 888, the Petitioners retain the obligation to undertake any necessary system expansion at the higher of incremental or embedded cost. Thus, there is no undue discrimination.

30. Regarding United Illuminating's argument for a rulemaking proceeding, we agree with Petitioners that such a rulemaking proceeding is unnecessary because we are not establishing any new rules of general applicability.

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[29] Petition at n.13. These commitments must be consistent with Petitioners' obligations regarding expansion under Order Nos. 888 and 890.

[30] The Petitioners state that 200 MW of additional capacity will be participant funded under the same rates, terms and conditions as the HQUS Transmission Service Agreement. Petition at 10-11.

2. Merchant Transmission

a. Protests

31. A common theme in a number of the protests is that the Petitioners have proposed a merchant transmission project that does not meet the Commission's criteria for approval. For example, New England ITC asserts that regardless of Petitioners' claim, the Project is a merchant transmission facility and should be analyzed according to the "ten safeguards" applied by the Commission to merchant transmission projects.[31] New England ITC states that despite the Petitioners' attempt to characterize the proposal as a participant funded transmission line with negotiated rates and not market-based rates, their description of the Project is not correct. According to New England ITC, "the use of negotiated rates applied through a bilateral contract is in essence the same as market based rates (for this scenario)."[32] New England ITC asserts that by classifying this Project otherwise, Petitioners are attempting to avoid Commission policy for competition as well as ISO-NE's planning process.

32. PSEG and New England ITC also assert that the Project will be a merchant transmission facility because the developers propose to assume all the risks of the Project in exchange for the profits made from the sale of service on the line.[33] New England ITC claims that this same concept formed the basis of the merchant proposals in *TransÉnergie*[34] and *Neptune*,[35] where these project developers assumed the entire risk of the projects and the investors' profits were dependent upon willing buyers of the transmission rights at rates that recovered the projects' costs and earned any return on their investment. New England ITC argues that to the extent the Petitioners' Project differs from other merchant transmission projects, the Commission has the authority to reject those parts that it finds unnecessary or fails to satisfy the criteria.[36]

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[31] New England ITC Protest at 17 – 20, citing *Northeast Utilities Service Co.*, 97 FERC ¶ 61,026 (2001); *Northeast Utilities Service Co.*, 98 FERC ¶ 61,310 (2002); *Sea Breeze*, 112 FERC ¶ 61,295 (2005); *Linden VFT, LLC* 119 FERC ¶ 61,066 (2007).

[32] *Id.* at 8.

[33] PSEG Comments at 9; New England ITC Comments at 9.

[34] *TransÉnergie U.S., Ltd.*, 91 FERC ¶ 61,230 (2000) (*TransÉnergie*).

[35] *Neptune Reg'l Transmission Sys., LLC*, 96 FERC ¶ 61,147 (2001) (*Neptune*), *order on reh'g*, 96 FERC ¶ 61,326, *order on reh'g*, 103 FERC ¶ 61,213 (2008).

[36] New England ITC Comments at 12.

33. Cargill rejects Petitioners' claim that this Project is akin to a generator lead line. Cargill asserts that the line would be part of ISO-NE's integrated grid and could also be used to deliver power from other generation facilities, which would, by definition, make this something other than a generator lead line.[37] Several protesters assert that Petitioners' reliance on *Cross Hudson* [38] is misplaced in that *Cross Hudson* was a generator lead line and this Project is not. Specifically, Competitive Suppliers argue that *Cross Hudson* was not part of an integrated grid, and that the Commission stated that if any electric energy being transmitted on the line comes from a source other than Bergen 2, it would reevaluate the project's rates.[39] Competitive Suppliers also contend that in *Cross Hudson* the associated generator was financially dependent on the project, but in this case there is no associated generator dependent on this Project. Indicated NE Generators also argue that this proposal is not a generator lead line because, as Petitioners state, the line will be used for both importing power from and exporting power to Québec.[40] Cargill also argues that this Project differs from a classic anchor-shipper model because: (1) HQUS will purchase all of the capacity proposed by the Project rather than a portion of the capacity; and (2) other anchor-shipper transmission lines would be used to enable the construction of otherwise infeasible renewable energy projects, while these hydroelectric projects will be built regardless of whether the Project is constructed.[41]

34. Further, while Petitioners claim that the Project is not a merchant line, protesters disagree. Protesters assert that the Project is similar to other merchant transmission projects and as such must include an open season. For example, Iberdrola Renewables states that, even though the rates negotiated between the parties to the Transmission Service Agreement may have some relationship to the project's costs, this is not sufficient to excuse the Petitioners from the Commission's open season requirements associated with merchant transmission projects.

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[37] Cargill Comments at 8.

[38] *Cross Hudson*, 123 FERC ¶ 61,001 (2008).

[39] Competitive Suppliers Protest at 8, citing *Cross Hudson*, 123 FERC ¶ 61,001 at P 22.

[40] Indicated NE Generators Protest at 23.

[41] Cargill Comments at 9, 10.

35. PSEG contends that Petitioners' proposal is similar to *Neptune*,[42] where the Commission denied Neptune's proposal to secure 30 percent of its transmission capacity through negotiated agreements. United Illuminating further points out that the Commission has similarly required Northeast Utilities to fulfill the open season requirement to charge negotiated rates for a merchant transmission line between New York and ISO-NE. According to United Illuminating, the circumstances here are no different.[43]

36. Several Protesters disagree with Petitioners' claim that this Project is analogous to the Phase I/II Transactions. These Protesters assert that those transactions are thirty years old, predate Order Nos. 888 and 890, would not comply with current Commission requirements, and currently offer transmission service pursuant to rate schedules in the ISO-NE OATT.[44] Brookfield Energy contends that the transmission rights offered in Phase I/II were only offered to the supplier for the term of the power purchase agreement and afterwards, the utility owners made those transmission rights available to competing suppliers on an open access basis. Under Petitioners' proposal, HQUS would have exclusive access to the transmission rights beyond the term of the power purchase agreements. Indicated NE Generators assert that, unlike the Petitioners' proposal, the Phase I/II proposal offered transmission rights to all New England Utilities that were interested in sharing the cost of the line.

37. Indicated NE Generators also assert that contrary to the Petitioners' arguments, the Cross-Sound Cable project is clearly distinguishable from Petitioners' Project, because the Cross-Sound Cable project is a merchant line with market-based rates, is not owned by the monopoly service provider and it is not assured a certain return. Additionally protesters claim that the Cross-Sound Cable also serves a market where the capacity products are not unbundled from the monopoly service providers. By contrast, here the monopoly service providers are all government authorities or municipalities.[45]

38. Finally, Indicated NE Generators also state that the Commission's holdings in *California Independent System Operator Corporation*[46] do not support the Petitioners'

[42] *Neptune*, 96 FERC at P 61,634.

[43] United Illuminating Comments at 13.

[44] Brookfield Marketing Comments at 7; Indicated NE Generators Comments at 19.

[45] Indicated NE Generators Comments at 20.

[46] *Cal. Indep. Sys. Operator Corp.*, 120 FERC ¶ 61,244 (2007) (*CAISO*).

(continued)

Project. They assert that in *CAISO*, the Commission recognized that no one generator could bear the cost of the transmission project, and that the Commission's own policies were a barrier to needed infrastructure. Furthermore, the Commission also found that the mechanism used in that case would help foster competition, which Indicated NE Generators assert would not be the case here.

b. Answers

39. The Petitioners reiterate that the Project is not a merchant transmission facility because the transmission capacity will not be sold at market-based rates. The Petitioners request Commission flexibility in approving the proposal even though it involves a bilateral agreement with unique rates, terms and conditions, rather than involving a conforming Transmission Service Agreement under ISO-NE's OATT.[47] The Petitioners argue that the parties need to preserve flexibility to include negotiated rate provisions and other risk sharing provisions in the Transmission Service Agreement to facilitate completion of the transaction under difficult financial conditions by providing the necessary long-term financial commitments for construction of the line. The Petitioners note that because the Transmission Service Agreement will be filed pursuant to section 205, the Commission will have the opportunity to ensure that the rates, terms and conditions are just and reasonable. The Petitioners contend that "The Commission has expressly recognized the utility of models where participants fund projects in return for dedicated transmission rights."[48]

40. HQUS states that the magnitude and complexity of this transaction make bilateral negotiations the most efficient and effective route for moving this Project forward. HQUS argues that the process is reasonable because it is pro-competitive and involves three arm's length parties coming together to negotiate incremental supplies for the market. HQUS contends that the proposal should be allowed to proceed as requested arguing that open seasons are only one method for allocating capacity in new transmission and other methods such as first-come/first served are just as reasonable and non-discriminatory.[49]

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[47] Petitioners Answer at 20.

[48] Petitioners Answer at 14, *supra* n.25.

[49] HQUS Response at 9, 10.

c. Commission Determination

41. In response to the protesters' arguments that the Project is a merchant transmission project, the Commission disagrees and finds that the Project is not a merchant transmission project. As we noted in the recent *Chinook* order, merchant transmission projects are distinguished from traditional public utilities in that the developers of merchant projects assume all the market risk of a project and have no captive customers from which to recoup the cost of the project.[50] Here, the risks of the Project have been shifted from the Petitioners to HQUS, which has agreed to participant fund the Project, and thus has full financial responsibility for the Project. The Petitioners, which operate in retail access states, indicate that they have no captive customers. Also, the costs of the Project will ultimately be recovered from any party that purchases power under the power purchase agreement. We therefore find protesters' arguments regarding merchant transmission projects, including their arguments regarding open season requirements, to be misplaced, as is their reliance upon Commission precedent such as *TransEnergie* and *Neptune* involving merchant transmission projects. This is a cost-based participant funded transmission project that the Petitioners are undertaking at the request of HQUS who has agreed to participant fund the project.

42. Petitioners will file the necessary supporting cost documents in a future section 205 rate case, which the Commission will review to ensure that the proposed cost-based rate is just, reasonable, and not unduly discriminatory or preferential. We recognize that Petitioners want to preserve flexibility to include negotiated rate provisions and other risk sharing provisions in the Transmission Service Agreement that is ultimately filed, but the burden will be upon Petitioners to demonstrate that any such flexible terms and conditions are not unduly discriminatory or preferential at the time they make that filing. Because HQUS has agreed to participant fund the transmission expansion, the Project costs will not be included in the rates for transmission service under the ISO-NE OATT and other transmission ratepayers will be held harmless from the costs of the expansion.

43. We reject the claim that the Project is similar to *Cross-Hudson or Cross Sound Cable*. The Commission approved negotiated, non-cost based rates in those cases finding that the projects were merchant transmission projects. The Commission finds that any reliance by either the Petitioners or the protestors on these cases is misplaced because we are approving the structure of the Project, which is a participant funded project and not a

[50] *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 (2009) (*Chinook*).

merchant transmission project. Thus the transmission capacity charges will be priced based on the cost of the line. Similarly, we find our holding in *CAISO*[51] is distinguishable from our finding in this case. In *CAISO*, the Commission waived certain Order No. 2003 default generator interconnection policies. This proceeding does not involve a generator interconnection.

3. Bundled Rates

a. Protests

44. Several commenters argue that because Petitioners are planning on bundling the transmission and generation rates, it will be impossible to determine if the Project is in fact participant funded as the Petitioners claim.[52] For example, Indicated NE Generators assert that the Petitioners are proposing a series of related agreements that rebundle transmission and generation, which will prevent alternative suppliers from competing for the load that HQUS will have "locked up" already. They also argue that because Northeast and NSTAR will rely on their ratepayers to fund this Project, it will not truly be participant-funded. Moreover, because Northeast and NSTAR, will be purchasing the power through rebundled rates, they will be passing on the risk of this Project to their captive customers.[53] Indicated NE Generators also argue that the Commission's Standards of Conduct do not address or authorize this type of arrangement. They claim that Order No. 2004 did not modify the restrictions regarding unbundling, as Petitioners imply.[54]

b. Answer

45. The Petitioners state that the proposed transaction does not violate the Commission's functional unbundling requirements, because the agreements and rates for transmission and generation will be distinct and separately stated.[55] The Petitioners also state that the rates, terms and conditions of the power purchase agreement will be filed

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[51] *CAISO*, 120 FERC ¶ 61,244.

[52] Commenters include Competitive Suppliers at 8, 12, Indicated NE Generators at 10-15, and PSEG at 6, 7.

[53] Indicated NE Generators Protest at 13.

[54] *Id.* at 15, 16.

[55] Petitioners Answer at 15, 16.

and reviewed by the Commission and relevant state regulatory authorities who will ensure that New England customers are getting a "fair deal." The Petitioners argue that the power purchase agreement will occur under HQUS' market-based rate authority, and will be subject to the Commission's applicable reporting requirements. Thus, there is no need for the Petitioners to file further information regarding the power purchase agreement.[56]

c. Commission Determination

46. In order for a transmission provider to meet the Commission's functional unbundling requirements, rates for generation, transmission, and ancillary services must be separately stated. The Petitioners have indicated that the rates for transmission services and power purchases with respect to the Project will be separately stated, [57] and the Commission will require that they do so. It is true that HQUS (but not the Petitioners) is combining renewable hydropower generation costs (that will be sold at market rates) with the costs that HQUS will incur to participant-fund the new transmission line that needs to be built in order to deliver its hydropower resource to New England customers. However, that does not constitute of violation of the functional unbundling requirement of Order Nos. 888 and 890, because the rates for the transmission service and the power sales will be separately stated.

47. Further, the Petitioners will charge a cost-based transmission rate, and HQUS is agreeing to participant fund the costs of building the transmission line, which will hold other transmission customers in New England harmless from the transmission expansion costs. Such "rebundling" of transmission and generation occurs anytime a generator purchases long term transmission service to sell power. However, there are no "rebundling" concerns regarding the Petitioners because the transmission service and the cost-based rates charged will be provided for under the Transmission Service Agreement to be filed with the Commission, and any power purchases will separately occur under HQUS' Commission-approved market-based rate tariff.

48. Accordingly, the Commission finds that with the separately stated rates, the proposed transaction complies with the unbundling requirements of Order No. 888. We also find that no additional information regarding the power purchase agreement or Transmission Service Agreement is needed at this time. The Transmission Service Agreement is required to be filed with the Commission under section 205. Also, the power sales from HQUS will be made pursuant to a Commission-approved market-based

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[56] *Id.* at 27, 28.

[57] Petitioners have not stated whether ancillary services will be included.

rate schedule, which requires quarterly reporting of contracts and transactions.[58] No rates may be charged for jurisdictional services absent Commission approval.

49. Finally we reject both the Petitioners' and Indicated NE Generators' reliance on the Standards of Conduct. The Standards are not germane to the issues before us at this time, as we are asked only to approve the structure of the transaction. Any allegation regarding possible violations of the Commission's Standards of Conduct may be raised subsequently at the appropriate time. Further, the state commissions have filed comments in support of the structure of the proposed Project, noting that they will have the opportunity to review the impact of the transaction to ensure that the ratepayers are protected.[59]

4. Vertical Market Power, Affiliate Abuse Concerns and Need for Request for Proposal (RFP)

a. Protests

50. Nalcor Energy and Newfoundland and Labrador Hydro contend that the participation of transmission owners and their affiliated generation and load-serving operations in various elements of this transaction raises the potential for vertical market power, through preferential treatment of affiliated operations. "Here, there is no question that the proposed transaction brings together transmission-owning utilities in a joint transmission project that facilitates a specific purchase and sale of electricity at wholesale involving affiliated subsidiaries of the transmission-owning utilities."[60] They believe that without more detailed explanation to dispel these concerns, measures that mitigate potential vertical market power must be a condition of any Commission approval, and that an open season to solicit participants is an appropriate means of doing this. Similarly, Ridgewood Renewable Power asserts that this Project will amount to one

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[58] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 73 Fed. Reg. 25,832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, *order on reh'g and clarification,* 124 FERC ¶ 61,055 (2008).

[59] Connecticut PUC and Connecticut Office of Consumer Counsel Comments at 3.

[60] Nalcor Protest at 8-10.

company having exclusive access to markets, and that access could limit competition and market access for others.[61]

51. Iberdrola Renewables argues that Petitioners have failed to address the affiliate abuse concerns inherent in their proposal; i.e. the Petitioners and the transmission-owning affiliate of HQUS, HQ TransÉnergie, are working together to develop this Project. Iberdrola Renewables contends that the Commission has generally favored separating the development of new generation from the planning of transmission system. Iberdrola Renewables acknowledges the need for an "anchor shipper" in order to finance a new project, but states it is concerned about affiliate abuse because HQUS will have control over the entire capacity of the line.[62] Central Vermont states that while generally it supports the proposal, it is concerned that HQUS could give undue preference to HQUS' power purchasers. Thus, Central Vermont requests that the Commission reserve judgment on the specific terms and conditions of the Transmission Service Agreement and the power sales agreements until the details of those transactions are provided in a subsequent filing with the Commission.[63]

52. Indicated NE Generators assert that Petitioners imply that they will be the purchasers of HQUS' power. Because this purchase will take place at negotiated rates and involves no competitive offers from other suppliers, what starts as an unbundled relationship will effectively become a bundled agreement with Northeast and NSTAR favoring the power they purchase from HQUS over any possible competing suppliers.[64] New England ITC argues that if Petitioners were to conduct a request for proposal process (RFP), both open season and affiliate abuse concerns would be addressed because the Commission has found that an RFP can be consistent with the open season criteria for merchant transmission projects.[65] United Illuminating argues that the

[61] Ridgewood Preliminary Comments at 3, 4.

[62] Iberdrola Protest at 4, 5.

[63] Central Vermont Comments at 1, 7.

[64] Indicated NE Generators Protest at 19.

[65] New England ITC Comments at 20, citing *Conjunction LLC*, 108 FERC ¶ 61,090, at P 13 (2004).

Commission has rejected this type of bilateral transmission contract because it can result in unduly preferential access to transmission capacity.[66]

b. Answer

53. The Petitioners state that the proposed transaction does not involve any affiliate transactions because HQUS is not affiliated with either Petitioner and that the transaction was conducted at arms' length. Further, the Petitioners state that they do not have captive customers because of retail choice and, therefore, the potential for affiliate abuse does not exist. HQUS states that vertical market power concerns are unfounded, because HQUS and Hydro-Québec Production are physically and functionally separated from TransÉnergie, the entity building the transmission capacity on the Québec side. Further, HQUS notes that TransÉnergie has a code of conduct and an approved OATT for evaluating transmission requests in a non-discriminatory manner. Petitioners note that Hydro-Québec Production was the first party to request 1,200 MWs of transmission service on the Québec portion of the Project to the U.S. border[67] and thus has service priority on the Québec side.

c. Commission Determination

54. The Commission finds that Hydro-Québec, HQUS and its subsidiaries are not affiliated with the Petitioners and, therefore, the possibility of affiliate abuse does not exist. Regarding concerns of vertical market power, a minimum requirement for the possession of vertical market power is the ability to control more than one stage of production, in this case, generation and transmission. However, the Petitioners are ceding control of the Project to ISO-NE. Therefore, the Petitioners will not be able to use the transmission system, a downstream asset, to control or manipulate generation. Therefore, we find that Petitioners' ceding control of the U.S. portion of the line to ISO-NE mitigates vertical market power.

55. In addition, Petitioners have stated that HQUS will sell electricity to them and other interested parties pursuant to HQUS' Commission-approved market-based rate tariff.[68] HQUS confirms Petitioners' representation and also offers that it will commit in the Transmission Service Agreement to making unused capacity available to third parties

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[66] United Illuminating Comments at 11, 12 citing *Neptune*, 96 FERC ¶ 61,147 at 61,634.

[67] Petition at 21, 22.

[68] Petition at 5, 6.

pursuant to Order No. 890. The Commission requires that, as a condition of being able to sell electricity under this tariff, HQUS must periodically demonstrate that it possesses no horizontal or vertical market power.[69]

56. Finally, United Illuminating's comparison of the Commission's rejection of the bi-lateral contracts proposed in *Neptune* is misplaced. *Neptune* was a merchant project with market-based rates. As we have previously discussed, this project is not a merchant project but is participant-funded, and transmission capacity will be priced at cost-based rates.

5. <u>ISO-NE's Regional Planning Process</u>

a. <u>Protests</u>

57. Several protesters question why Petitioners have chosen to work outside of ISO-NE's normal regional transmission planning processes. For example, Cargill asserts that Order No. 717[70] does not justify Petitioners' ignoring the ISO-NE planning process. Brookfield states that even if the Project is not a merchant line, Petitioners have failed to show why the Project should not be treated as an elective transmission upgrade under ISO-NE's tariff. United Illuminating lays out the process provided by the ISO-NE tariff for obtaining additional transmission service, including System Impact Study provisions that could be pursued by HQUS, and it asserts that this process would also indicate if additional facilities are necessary to accommodate the additional transmission service. United Illuminating concludes that the existing ISO-NE OATT process is adequate to serve HQUS' service needs and that Petitioners did not explain why the Project cannot be completed within the ISO-NE regional planning process and the ISO-NE OATT.[71]

[69] "Through regularly scheduled updated market power analyses . . . the Commission is better able to evaluate the ongoing reasonableness of . . . sellers' charges and to provide for an ongoing assessment of their ability to exercise market power." *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at 40,005, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 73 Fed. Reg. 25,832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008).

[70] Order No. 717 amends regulations adopted on an interim basis in Order No. 690, in order to make them clearer and to refocus the rules on the areas where there is the greatest potential for abuse.

[71] United Illuminating Comments at 4.

58. Brookfield argues that, contrary to Petitioners' assertions, the Commission's most recent views on transmission policy are found in Order No. 890, which lays out nine planning principles to ensure that transmission services are provided on a just, reasonable and not unduly discriminatory or preferential basis. Brookfield asserts that the Petitioners' proposal fails to address the first five principles: coordination, openness, transparency, information exchange, and comparability. Brookfield further maintains that it is premature to claim that this proposal fits within ISO-NE's regional plans, because ISO-NE is currently considering Petitioners' proposal, along with several others.[72]

59. National Grid states that while it generally supports the Project, it must be subject to appropriate review by ISO-NE to ensure it will not adversely affect reliability. Moreover, bypassing the Regional System Planning Process would tend to undermine the Commission's policies for transparency in the transmission planning process and deprive stakeholders of the opportunity to review the proposed interconnection.[73] It also contends that participant funding should be required for any AC transmission reinforcements necessary to accommodate the proposed interconnection, because it is not clear that such reinforcements would benefit all transmission load customers in the region.[74] PSEG also argues that the Project must undergo review by ISO-NE, asserting that other studies have shown that large imports of power from Canada can negatively affect PJM's and NYISO's systems. PSEG also raises concerns about who will pay for these impacts.[75]

60. ISO-NE explains that the Project will be fully vetted through its planning process. ISO-NE agrees with the Petitioners that this Project will increase fuel diversity and reduce supply risks and price volatility. ISO-NE states that the line would not be considered an elective network upgrade because it is not a pool transmission facility. Therefore, ISO-NE argues that because the Project's transmission line would not fit under existing OATT provisions, Petitioners' proposal for participant funding is a logical option.

61. ISO-NE argues that the proposed bilateral transaction would not be workable for transmission projects within ISO-NE because service within ISO-NE is not offered on a

[72] Brookfield Comments at 6.

[73] National Grid Comments at 8.

[74] PSEG Comments at 13.

[75] *Id*.

point-to-point basis or pursuant to a bilateral power supply arrangement. ISO-NE claims that it is prepared to undertake the studies and review processes specified in Section I.3.9 of its tariff to ensure the transmission line will not adversely affect reliability or operations. ISO-NE asserts that it should play a key role in ensuring a transparent decision-making process for the southern terminus of the line to ensure that the entire region does not need to support any network upgrades resulting from the Project.[76]

b. Answer

62. The Petitioners state that concerns that it is bypassing the ISO-NE planning process are unfounded. They state that ISO-NE will not have to evaluate the need or the economic benefits of the Project because it is participant-funded and the costs will not be included in rates for transmission service under ISO-NE's OATT. The Petitioners state that the Project will, however, be vetted through ISO-NE's stakeholder process. They also state that to the extent necessary, they will conduct a System Impact Study in coordination with ISO-NE and other affected transmission owners to determine any effects the proposed line may have on the regional transmission grid. The Petitioners state that ISO-NE has determined that the transmission line is not an elective upgrade and is not considered a pool transmission facility and, thus does not fit under any existing OATT provisions. The Petitioners also confirm that they will assume responsibility for the costs of the Project, including any network upgrades to the existing ISO-NE transmission system that are solely required to accommodate the line. They state that any needed network upgrades to the AC transmission system independent of the proposed Project should be made pursuant to ISO-NE's OATT.[77]

c. Commission Determination

63. The Commission accepts ISO-NE's and Petitioners' statements that the Project will be thoroughly vetted through the ISO-NE's stakeholder planning process. Under its regional system planning process, ISO-NE will be responsible for determining, in consultation with interested parties, whether any reliability transmission upgrades are needed to interconnect the Project to the regional AC transmission system. The Petitioners will be responsible for the costs of the Project as well as any network upgrades to the existing ISO-NE transmission system that are needed to accommodate the line. The Commission also accepts Petitioners' representations that it will submit a Transmission Operating Agreement to ISO-NE for its approval and that the Project will undergo ISO-NE's section I.3.9 reliability review process to ensure that it does not cause

[76] ISO-NE Comments at 8.

[77] Petitioners' Answer at 24, 25.

any adverse effects to system reliability.[78] Because ISO-NE commits to playing a key role in reviewing the effects of the project and ensuring that the reliability review process is transparent vis-à-vis the U.S. portion of the line, the Commission finds that this oversight will address any potential that other parties would be required to pay for facilities to accommodate the interconnection of the transmission line.

6. Rights to Unused Capacity and Capacity Rights After Contract Termination

a. Protest and Comments

64. Indicated NE Generators request that the Petitioners clarify how scheduling will be conducted to accommodate competitive supply and demand on both sides of the international border. They are concerned that HQUS will have scheduling rights for more than the twenty to twenty-five year term of the power purchase agreement because the line will be amortized over a longer time period.[79] Nalcor Energy and Newfoundland and Labrador Hydro state that unused capacity must be made available in a complete, open, and robust secondary market and that Petitioners should be required to explain how this will be done prior to Commission approval. Nalcor Energy explains that the Petitioners have stated only that they intend to make unused capacity available but have provided no details as to how that would be implemented. In addition, Nalcor Energy asserts that the Commission should recognize that the Transmission Service Agreement may have unique provisions governing scheduling rights.[80]

65. National Grid states that any order approving the Project should be conditioned upon the Petitioners making available unused capacity under the Commission's open access requirements.[81]

b. Answer

66. The Petitioners commit to making any unused capacity available consistent with the requirements of Order No. 890. The Petitioners also state that the Transmission Service Agreement will include a provision stating that secondary transmission service

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[78] FERC Electric Tariff No. 3, General Terms and Conditions, Section I.3.9.

[79] Indicated NE Generators Protest at 32, 33.

[80] Nalcor Energy Comments at 10, 11.

[81] National Grid Comments at 7.

will be available to other parties at the same rates, terms and conditions as HQUS.[82] In response to concerns that it will continue to have rights to 1,200 MW of firm transmission service after the end of the initial term of the power purchase agreement, HQUS states that there is no reason, financial, equitable or legal, why an entity responsible for the transmission line's existence and still paying for the line should not have capacity rights on the line.[83]

c. <u>Commission Determination</u>

67. We find that it is not inconsistent with our policy to grant HQUS transmission rights for the entire 1,200 MW capacity of the line as long as it continues to fund the line.[84] In the past, we approved a cost-based transmission project wherein the transmission rights were not tied to the length of any other agreement, such as financing or a Transmission Service Agreement.[85] We will fully resolve the question of the appropriate length of transmission rights in Petitioners' future section 205 filing. We note that the Petitioners must make available any unused Project transmission capacity pursuant to the requirements of Order No. 890.

7. <u>Recovery of Potential Abandoned Plant Costs</u>

a. <u>Protest and Comments</u>

68. National Grid requests that the Commission find that the Petitioners are not eligible to collect abandoned plant costs "for the construction of participant-funded transmission facilities designed to benefit only a subset of power purchases in New England."[86]

b. <u>Answer</u>

69. In response to National Grid's concern, the Petitioners state that under their existing TOA with ISO-NE, they do not take the position that they are entitled to recover prudently incurred abandoned plant costs if ISO-NE removes a project from a Regional

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[82] Petitioners' Response at 29.

[83] HQUS Response at 6.

[84] *See supra* note 27.

[85] *Id.*

[86] National Grid Comments at 11.

System Plan after directing that the project moves forward, but they reserve the right to file for recovery of these costs, including as an incentive under Order No. 679.[87] The Petitioners also argue that the Commission has no reason to prejudge the Order No. 679 issue in this case, but any such request, if made, would be part of the future section 205 filing of the Transmission Service Agreement.[88]

c. Commission Determination

70. Petitioners have not requested a determination that abandoned plant costs could be recovered, and we will therefore reject as premature National Grid's argument against the potential recovery of abandonment costs. As the Petitioners correctly note, they must make a separate request or filing with the Commission to recover any future abandonment cost. We will address this issue as necessary at that time.

8. Lack of Sufficient Data to Support the Filing

a. Protest and Comments

71. Several commenters and protesters note that the proposal lacks detail. Those opposed to the Project view the missing information as undermining the Commission's ability to make a determination of the proposal. Commenters in favor of the proposal state that the Commission should limit its approval to the very narrow question put before it by the Petitioners.

72. As an example, Brookfield states that the Commission cannot fully evaluate the impact of the Project without further detail about: (1) what impact this Project will have on ratepayers; (2) what impact this Project will have on competing suppliers in terms of line capacity and any potential upgrade; (3) where the line will interconnect and what impact that will have on the ISO-NE-wide grid; (4) what alternatives there are to the proposed import of hydropower from Québec; and (5) what impact these imports will have on the wholesale market.[89] Direct Energy Services requests that the Commission require Petitioners to detail how and to whom the power procured and transmitted over the Project ultimately would be sold, and to provide more information on why this

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[87] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[88] Petitioners' Response at 26.

[89] Brookfield Comments at 13-19.

Project cannot conform to Order No. 890.[90] Indicated NE Generators state that details as to the rates, terms, and conditions of the various agreements that will differ from the Commission's *pro forma* OATT is needed to evaluate Petitioners proposal. Indicated NE Generators also assert that the Petition lacks detailed information about the terms and conditions of various agreements that will be involved in the operation of the proposed transmission line, including the Transmission Service Agreement and the power purchase agreements. Petitioners have not provided details as to the process by which interested parties might obtain power from HQUS or the terms under which that power might be sold. According to Indicated NE Generators, significant operational details, such as how the power will flow and how scheduling will be conducted, are also missing.[91]

73. Green Mountain Power supports construction of additional transmission facilities that could be used to import power from Québec, but expresses concern about the need for details concerning the proposed Transmission Service Agreement: (1) how will the rates, terms and conditions differ from the Commission's *pro forma* OATT; (2) how the proposed risk sharing arrangements will operate; or (3) how the unique provisions governing scheduling rights will be implemented. Therefore, Green Mountain Power advises the Commission to approve the petition as narrowly presented and addressing only the structure of the transaction.[92] National Grid states that it supports the proposal only if the Commission requires that all subsequent rates, terms and conditions are reviewed.[93]

74. The Connecticut PUC and Connecticut OCC also filed comments in support of the proposed transactional structure but state that, at this time, they take no position as to the particular rates, terms, and conditions of service that will be embodied in the contracts contemplated by the Petitioners.[94] The Massachusetts Attorney General also filed comments supporting importing more hydropower from Québec into New England but only if it results in reducing the total delivered cost of power to consumers. He states that at this time the Commission can only approve the proposal in principle because more

[90] Direct Energy Comments at 4, 5.

[91] Indicated NE Generators at 32 – 34.

[92] Green Mountain Power at 6, 7.

[93] National Grid Comments at 7.

[94] Connecticut Office of Consumer Counsel Comments at 2; Connecticut DPUC and Office of Consumer Counsel at 2, 4.

information is needed to determine if the proposed Project is in the public interest.[95] Finally, the Vermont DPS believes the proposed transaction is creative and could be a model for future transactions. However, it is concerned about the details of the power purchase agreement, including whether Vermont load serving entities will have an opportunity to purchase power made available by this line. Vermont DPS also expresses concern that there be no undue preference in the purchase of power from HQUS.[96]

b. Answer

75. Petitioners and HQUS state that the Protesters' claim that the filing lacks sufficient information regarding the power purchase agreement is without merit. They assert that they are still negotiating the terms and conditions of both the Transmission Service Agreement and the power purchase agreement, and once executed they will make the necessary section 205 filings with the Commission.[97] HQUS explains that under the power purchase agreement, buyers will most likely have to file the contracts with their respective state utility commissions for prior review; therefore, any state regulatory concerns will be addressed at that time.[98] The Petitioners also state that concerns regarding whether the power sold will be competitively priced relative to other resources is not relevant to this proceeding because the power sold by HQUS will be at market-based rates and subject to market forces. Load serving entities will either buy or not buy the power offered by HQUS, depending upon how competitive HQUS' power is vis-à-vis alternative power sources.[99]

c. Commission Determination

76. The Commission agrees with HQUS and the Petitioners that the Commission does not require additional information in order to approve the petition. As the Petitioners state, when required, they will make the appropriate section 205 filings that will include cost support in compliance with Part 35 of the Commission's Regulations.[100] Accordingly, we reject as premature Protesters' requests for additional information

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[95] Massachusetts Attorney General at 6.

[96] Vermont DPS Comments at 3.

[97] Petitioners' Response at 27; HQUS Response at 8.

[98] HQUS Response at 8.

[99] Petitioners' Response at 28.

[100] *See* 18 C.F.R. § 35.13 (2008).

concerning the Transmission Service Agreement. Similarly, we will reject Protesters request for additional information regarding the power purchase agreement because the power sales under that agreement will be provided under HQUS' Commission-approved market-based sales tariff, and HQUS will be required to comply with all relevant reporting requirements. We remind the Petitioners that they will be required to file, when appropriate, the Transmission Service Agreement and the TOA. We emphasize that the Petitioners must file any other agreements related to the Project not otherwise discussed in the Petition that involve jurisdictional services.

9. Monopsony Power and Impact on the Forward Capacity Market

a. Protests

77. Indicated NE Generators and NRG argue that the Project will foster monopsony market power and undermine competitive markets in New England. This concern is based in part on the excess capacity found to exist in the ISO-NE's forward capacity market.[101] Indicated NE Generators and NRG Companies assert that adding such a large amount of capacity will artificially suppress prices in the ISO-NE forward capacity market, because they would be placed in the bid stack as price-takers. If the Project is uneconomic, relative to ISO-NE's current forward capacity market, Petitioners should not be allowed to enter the market and suppress prices. Indicated NE Generators also question the benefits of power imported from Québec and whether it will be favorable compared to alternatives and this cannot be determined without knowing the price at which the power will be made available and the price of the alternatives. Indicated NE Generators state that the power purchase agreement will have a term of at least twenty years, yet Petitioners did not even speculate on what price other suppliers would offer for a twenty year purchase agreement.

78. In addition to questioning the need for this capacity, NRG expresses the concern that the Project could undermine the proper functioning of the New England forward capacity market, because the proposal contains no competitive procurement process,

[101] Both Indicated NE Generators and NRG point to the results of the Forward Capacity Auction for June 2010 through May 2012, which indicate a significant excess of capacity in New England. They explain that ISO-NE reported the excess capacity in the first forward capacity market was 2.047 MW, citing Letter from ISO New England in Docket No. ER08-633-000 (March 3, 2008). They also cite Letter from ISO New England filed in Docket No. ER09-467-000 (December 23, 2008) that reported excess capacity in the second Forward Capacity Auction was 4,744 MW. Indicated NE Generators Protest at 26, 27 and 18 n.42. NRG Protest at 4 n.4.

there is no guarantee that the additional capacity is economic, and the existing forward capacity market rules are not sufficient to protect against the anti-competitive effects of uneconomic entry.[102] This view is echoed by Indicated NE Generators: "[I]t nonetheless is beyond debate that the price of capacity in a competitive market such as New England should not be subject to manipulation by large load-serving entities that can exercise monopsony power, be it intentional or not."[103]

79. NRG Companies request that the Commission review the proposal to ensure it is not anti-competitive, asserting that large net-buyers such as Northeast and NSTAR have an incentive to depress capacity market prices. Further, they argue that Petitioners should be required to clarify how their proposal will avoid having anti-competitive effects on the forward capacity market. Finally, NRG states that the Commission should: (1) direct ISO-NE and its stakeholders to review existing forward capacity market rules and make revisions as necessary to avoid a long-term price collapse, and (2) clarify that new capacity delivered via this Project is not guaranteed to be allowed to participate in the forward capacity market until there is a thorough review of its competitive effects.[104]

b. Answer

80. The Petitioners state that the Protesters' arguments regarding monopsony power and criticisms of ISO-NE's existing forward capacity market rules are outside the scope of this proceeding and should be dismissed. The Petitioners state that the forward capacity market design envisions that load will be able to meet capacity obligations through bilateral contracts. The Petitioners state that the Project will be subject to existing market mitigation rules, and that any concerns over those rules should be addressed in the ISO-NE stakeholder process. The Petitioners also contend that NRG's and Indicated NE Generators' assertion that the existing forward capacity market rules are inadequate represents an improper collateral attack on the Commission's prior orders.[105] Petitioners conclude that their proposal is pro-competitive because it will

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[102] NRG Protest at 4 – 6.

[103] Indicated NE Generators Protest at 28.

[104] NRG Protest at 8.

[105] Petitioners' Response at 11-12 (citing *ISO New England Inc.* 122 FERC ¶ 61,018, at P 4 (2008), *Devon Power LLC*, 115 FERC ¶ 61,340, at P 109 (2006), *order on reh'g*, 117 FERC ¶ 61,133 (2006), *NSTAR Electric Co. v. ISO New England Inc.* 125 FERC ¶ 61,187, at P 26 (2008), *ISO New England Inc.*, 123 FERC ¶ 61,290, at P 16 (2008)).

increase supply in New England's wholesale power market and, in turn, may reduce market prices and benefit customers.

c. **Commission Determination**

81. We agree with Petitioners that the issues raised by Indicated NE Generators and NRG concerning the adequacy of the existing forward capacity rules are beyond the scope of this proceeding. Furthermore, any concerns regarding the forward capacity market rules are best addressed in the ISO-NE stakeholder process.

The Commission orders:

NSTAR and Northeast's petition for a declaratory order approving the structure of the proposed transaction, as discussed in the body of this order, is hereby granted.

By the Commission. Commissioner Moeller concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Northeast Utilities Service Company — Docket No. EL09-20-000

NSTAR Electric Company

(Issued May 22, 2009)

MOELLER, Commissioner, *concurring*:

This case presents a unique situation that calls for a unique response. Clarifying what this request is, and what it is not, is necessary to provide clear signals to potential developers and users of future transmission infrastructure. Each transmission project that comes before the Commission must independently satisfy our requirements with respect to non-discriminatory open access, market power and rate structure.

As the order explains, this proposal is not a merchant line given that the transmission rates charged will be subject to cost-based regulation. Additionally, this order finds that the proposed structure of the transaction does not violate the open access foundation of Order No. 888 and our subsequent determinations in Order. 890. While some parties to this proceeding argue that the proposed structure of the transmission project conflicts with our open-access and non-discriminatory transmission requirements, the parties have not clearly demonstrated how the Petitioners' request interferes with our existing requirements or Commission policy. At present, the Petitioners only seek approval of the basic structure of the transaction described in their filing and I find no compelling basis on which to deny their request.

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Philip D. Moeller
Commissioner

134 FERC ¶ 61,095
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Northern Pass Transmission LLC Docket No. ER11-2377-000

ORDER ACCEPTING TRANSMISSION SERVICE AGREEMENT

(Issued February 11, 2011)

1. On December 15, 2010, Northern Pass Transmission LLC (Northern Pass)[1] submitted a bilateral, cost-based transmission service agreement (TSA) executed on October 4, 2010 by Northern Pass and H.Q. Hydro Renewable Energy, Inc. (HQ Hydro) for service over the proposed Northern Pass Transmission Line (NPT Line). Northern Pass requested an effective date for the TSA of February 14, 2011. For the reasons discussed below, we will accept the TSA for filing to be effective on February 14, 2011.

I. Background

Declaratory Order

2. In orders issued on May 22, 2009 and December 29, 2009,[2] the Commission granted a petition for declaratory order in which Northeast Utilities and NSTAR sought approval of the structure of a transaction involving the NPT Line that would include a long-term, bilateral transmission service agreement. The Commission granted the

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[1] Northern Pass is a joint venture limited liability company formed by NU Transmission Ventures, Inc., a wholly-owned subsidiary of Northeast Utilities Service Co. (Northeast Utilities), and NSTAR Transmission Ventures, a wholly-owned subsidiary of NSTAR Electric Co. (NSTAR).

[2] *Northeast Utilities Service Company and NSTAR Electric Company*, 127 FERC ¶ 61,179 (May 22 Order), *reh'g denied*, 129 FERC ¶ 61,279 (2009) (December 29 Order) (together, Declaratory Orders).

petition subject to its further review (under section 205 of the Federal Power Act (FPA)) of the TSA, the Transmission Operating Agreement (TOA), and any other jurisdictional rate schedules.[3] The May 22 Order explained that when the TSA is filed, the Commission will evaluate whether the rates, terms, and conditions of the executed TSA are just, reasonable and not unduly discriminatory or preferential.[4]

3. In the Declaratory Orders, the Commission found that allocating all of the available capacity on the transmission line to HQUS absent an open season did not contravene the open access requirements of Order Nos. 888[5] and 890.[6] We held that providing for participant funding of a transmission facility with priority rights to use that facility is consistent with long-standing open access policies and does not constitute undue discrimination or preference.[7] The Commission further stated that any potential

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[3] While Northeast Utilities and NSTAR had filed the petition for declaratory order, Northern Pass is the signatory to the TSA. Similarly, while the petition referred to H.Q. Energy Services Inc. (HQUS), a U.S. subsidiary of Hydro-Québec, the other signatory to the TSA is HQ Hydro, a newly formed U.S. subsidiary of Hydro-Québec and an affiliate of HQUS.

[4] May 22 Order, 122 FERC ¶ 61,179 at P 17.

[5] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C**,** 126 FERC ¶ 61,228 (2009), *order on reh'g*, Order No 890-D, 129 FERC ¶ 61,126 (2009).

[7] On December 15, 2010, the same day Northern Pass made the instant filing of the TSA, Northern Pass filed an informational report in Docket No. EL09-20-000 providing information to the Commission with respect to a possible open season for an additional 200 MW of incremental capacity on the NPT Line. The report notes that, in an August 18, 2009 letter to NU and NSTAR, ISO-New England (ISO-NE) notified them

(continued…)

transmission customer has the right to request transmission service expansion from a transmission owning utility and that the owner is obligated to make any necessary system expansions and to offer service at the higher of an incremental cost or an embedded cost rate to the transmission customer.

4. The Commission also found that the transmission line project is not a merchant transmission project, but rather is a participant-funded, cost-based transmission project where the risk of the project has been shifted to HQUS, the customer, as opposed to a merchant transmission project where the transmission developer assumes the risk. We also found that the proposed use of bundled rates does not constitute a violation of the functional unbundling requirement of Order Nos. 888 and 890 because the rates for transmission service and power sales will be stated in separate rate schedules. We further found that the possibility of affiliate abuse does not exist because HQUS, and its subsidiaries are not affiliated with NU and NSTAR.

5. The Commission accepted ISO-NE and NU/NSTAR's statements that the project will be thoroughly vetted through the ISO-NE stakeholder planning process and that the project will undergo ISO-NE's Transmission, Markets and Services Tariff (Services Tariff) section I.3.9 reliability review process to ensure that it does not cause any adverse effects to system reliability.[8] Finally, the Commission acknowledged the statements of benefits by NU/NSTAR, including: additional low-cost hydro-electric power that should help reduce greenhouse gas emissions and the dependence on fossil fuels, increased fuel diversity, and reduced price volatility and lower locational marginal prices (LMP) in New England.

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that the maximum long-term, firm transfer capability for the NPT Line would be 1,200 MW. Based on ISO-NE's findings, Northern Pass concludes in the report that it cannot offer additional, long-term firm transmission service to third parties under rates, terms and conditions comparable to those with HQ Hydro.

[8] General Terms and Conditions, Section I.3.9 of the Services Tariff relates to Proposed Plan Applications from market participants and transmission owners. Proposed Plan Applications detail any new or materially changed plans for additions or changes to any generation or demand response facilities. Within 60 to 90 days of receiving the section I.3.9 Proposed Plan Applications, ISO-NE must respond in writing as to whether the proposed plan will have significant adverse effects on reliability of the transmission owner's facilities, on another transmission owner's facilities, or on the system of a market participant. If ISO-NE finds that the Proposed Plan Applications will not have adverse effects, the market participant or transmission owner may proceed.

II. Filing

A. Description of the Project

6. The United States portion of the transmission interconnection that will link the Hydro-Québec TransÉnergie (TransÉnergie)[9] system in Québec to the New England transmission system, known as the NPT Line, has an estimated cost of $1.1 billion. The NPT Line consists of (i) a 1,200 MW high voltage direct current (HVDC) transmission line, approximately 140 miles in length, from the United States-Canada border to a converter station to be constructed in Franklin, New Hampshire, and (ii) a radial 345 kV alternating current (AC) transmission line, approximately 40 miles in length, between the Franklin converter station and the Public Service Company of New Hampshire (PSNH) Deerfield substation in Deerfield, New Hampshire. The NPT Line will interconnect at the international border with a new transmission line (Québec Line) to be owned and constructed in Québec by TransÉnergie. Construction is expected to commence in 2013 and the line is expected to be in-service in late 2015.[10]

7. Under the terms of the TSA at issue in this proceeding, Northern Pass will develop, site, finance, construct, own and maintain the NPT Line. It will sell 1,200 MW of firm transmission service over the NPT Line to HQ Hydro over a 40-year term. HQ Hydro will be responsible for providing approximately $1.1 billion in initial construction costs and return on such costs, necessary additional capital expenditures and return, and other expenses associated with the line over the 40-year operating term of the TSA. HQ Hydro plans to recover these costs through competitive sales of wholesale power in the New England market.[11] Once the NPT Line becomes commercially operational, Northern Pass will transfer operating control of the line to ISO-NE pursuant to a TOA to be negotiated with ISO-NE.

8. In its transmittal letter, Northern Pass requests Commission approval under a number of alternative approaches under which the Commission would: (1) accept the TSA in its entirety as a *Mobile-Sierra* contract; (2) accept the TSA as a cost-based contract under the Commission's precedent; (3) accept the TSA using Commission Order

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[9] TransÉnergie is the transmission division of Hydro-Québec.

[10] Filing at 21.

[11] HQ Hydro will apply for market-based rate authority. *Id.* at 4 n.5. HQ Hydro also may enter into a power purchase agreement with PSNH, an affiliate of Northeast Utilities, for a small portion of the power delivered over the NPT Line, subject to state commission approval. *Id.* at 8 n.8.

No. 679 to justify TSA provisions that could be characterized as transmission "incentives;" or (4) accept the TSA because it qualifies for and would be granted incentives pursuant to the Commission's public policy standards under section 205 of the FPA in light of the significant public benefits produced by the NPT Line.

B. Formula Rate

9. Northern Pass proposes to use a formula rate to calculate HQ Hydro's payment for transmission service over the NPT Line. Northern Pass states that the formula in the TSA is a forward-looking formula rate that calculates costs on a prospective basis. Under the formula the projected costs are trued-up to actual costs in order to permit Northern Pass to recover the annual revenue requirement associated with the NPT Line and any AC upgrade costs. Northern Pass states that the formula rate recovers a return on Northern Pass's investment in the NPT Line plus associated income taxes, depreciation expense, operation and maintenance expenses, administrative and general expenses, municipal tax expense, and other expenses associated with the NPT Line (including AC upgrade costs).[12] Northern Pass explains that the formula allows it to project the revenue requirement for each calendar year and charge the resulting rates in that calendar year. Northern Pass claims that the formula rate in the TSA resembles formula rates that the Commission has accepted previously and also reflects Commission-approved ratemaking methodologies. Therefore, Northern Pass contends that the formula should be accepted.

C. Requested Incentives

1. Return on Equity

10. Northern Pass requests an overall Return on Equity (ROE) of 12.56 percent.

a. Prior to Commercial Operation

11. Prior to commercial operation, Northern Pass requests an ROE of 12.56 percent, consisting of a base ROE of 10.4 percent plus ROE adders of: (1) 50 basis points for Regional Transmission Organization (RTO) membership; and (2) 164 basis points for investment in new transmission.[13] Northern Pass states that the 12.56 percent ROE prior to commercial operation is for purposes of accruing allowance for funds used during construction (AFUDC).

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[12] *Id.* at 31.

[13] *Id.* at 37 and App. F, Ex. No. NPT-603.

b. After Commercial Operation

12. Northern Pass requests, upon commercial operation, an ROE equal to the base ROE under the ISO-NE Open-Access Transmission Tariff (OATT) (currently 11.14 percent) plus the lesser of an adder of 142 basis points (50 basis points for RTO participation, plus 92 basis points for investment in new transmission) or an amount that would not cause the total ROE to exceed the applicable zone of reasonableness.[14]

2. Termination Rights

13. Northern Pass explains that, under section 3 of the TSA, the parties have the right to terminate the TSA under certain circumstances subject to certain cost reimbursement obligations. During the development phase, the construction phase, or following commercial operation, Northern Pass states that HQ Hydro may terminate the TSA for convenience.[15]

14. Northern Pass explains that other scenarios under which the parties may terminate the TSA include the failure to obtain U.S. regulatory approvals for the NPT Line (section 3.3.5); failure to obtain the necessary Canadian regulatory approvals for the Québec Line (section 3.3.4); or a material, uninsured loss occurrence during commercial operations (section 3.3.9).[16]

3. Regulatory Asset

15. Northern Pass states that it is seeking authorization to establish a regulatory asset for certain costs that it has incurred and will continue to incur prior to the NPT Line's commercial operation date that do not meet the requirements to be included in Construction Work In Progress (CWIP) (FERC Account No. 107). Northern Pass maintains that, under the TSA, the parties have agreed that Northern Pass's recovery of such costs will be deferred until the project enters commercial operation and then will be recovered from HQ Hydro through the formula rate.

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[14] *Id.* at 11, 41-42, and App. F, Ex. No. NPT-600 at 3.

[15] *Id.* at App. A, Ex. No. NPT-100 at TSA §§ 3.3.2, 3.3.8, and 3.3.10.

[16] *Id.* at 61.

III. Notice of Filings and Responsive Pleadings

16. Notice of Northern Pass's December 15, 2010 filing was published in the *Federal Register*, 75 Fed. Reg. 81,597 (2010), with interventions and protests due on or before January 6, 2011. Notices of intervention and timely motions to intervene raising no substantive issues were submitted by Bangor Hydro Electric Company, GenOn Parties, TransCanada Power Marketing Ltd., National Grid USA, Brookfield Energy Marketing LP, Massachusetts Attorney General, ISO-NE, New Hampshire Electric Cooperative, NextEra Energy Resources, LLC, and the Massachusetts Department of Public Utility. New England Power Generators Association Inc. (NEPGA) filed a timely motion to intervene and protest. HQ Hydro filed a timely motion to intervene and comments. Meriden Hill Property Owners (Meriden Hill) filed a timely motion to intervene, request for hearing, and comments. The New Hampshire Public Utilities Commission and the Maine Public Utilities Commission filed out-of-time motions to intervene, raising no substantive issues. Northern Pass, HQ Hydro, and ISO-NE filed answers to the protest and comments.

IV. Discussion

A. Procedural Matters

17. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[17] the timely, unopposed motions to intervene and notices of intervention serve to make the entities that filed them parties to this proceeding.

18. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2010), the Commission will grant all late-filed motions to intervene given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

19. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest, unless otherwise ordered by the decisional authority. We will accept the answers submitted because they have assisted us in our decision making process.

B. Substantive Matters

20. As described further below, the Commission accepts the TSA without modification, including its provisions that reflect Northern Pass's request for ratemaking

[17] 18 C.F.R. § 385.214 (2010).

incentives pursuant to Order No. 679. The Commission also makes findings below regarding issues raised in the protest and comments, including unused transmission capacity on the NPT Line, the possible future rate treatment of the NPT Line by ISO-NE, access to information regarding certain possible upgrades in the Greater Boston area, environmental review concerns related to the NPT Line, and issues related to Hydro-Québec.

21. Because the Commission accepts the TSA without modification on the bases described below, we need not and do not reach the merits of the alternative approaches presented in Northern Pass's filing, including whether the TSA constitutes what Northern Pass characterizes as a "*Mobile-Sierra* contract."

1. <u>Eligibility for Incentives: Section 219 Requirements</u>

22. In the Energy Policy Act of 2005, Congress added section 219 to the FPA,[18] directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure. The Commission subsequently issued Order No. 679, which sets forth processes by which a public utility may seek transmission rate incentives pursuant to section 219, including the incentives requested here by Northern Pass.[19]

23. Order No. 679 provides that a public utility may file a petition for declaratory order or a section 205 filing to obtain incentive rate treatment pursuant to section 219. Through either procedural route, consistent with section 219, an applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion."[20] Order No. 679 established a rebuttable presumption that this standard is met if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project has received construction approval from an appropriate state commission or state siting authority.[21] Order No. 679-A clarifies the operation of this rebuttable presumption

[18] Pub. L. No. 109-58, 119 Stat. 594, § 1241.

[19] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[20] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76.

[21] *Id*. P 58.

by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[22]

a. Proposal

24. Northern Pass asserts that it is eligible for incentives under section 219, because the NPT Line will: (1) reduce the price of delivered power by reducing transmission congestion; (2) increase reliability by having another source of power on which to rely; (3) reduce costs to wholesale load customers;[23] (4) help meet environmental requirements for low carbon, renewable resources; and (5) provide enhanced access to hydro-electric power.

25. Northern Pass includes in its filing a study assessing the congestion reduction benefits of the NPT Line.[24] According to Northern Pass, this study demonstrates that the project will reduce congestion between Québec and ISO-NE, thus allowing economical power to be imported into the ISO-NE system. The study states that its base-case estimate of cost reduction to wholesale load customers will be $1.58/MWh in 2015 and $2.30/MWh in 2024, resulting in an estimated total cost reduction of $206 million in 2015 and $327 million in 2024. According to the study, without the additional capacity of the NPT Line, existing ties are expected to be fully utilized during 99.8 percent of peak hours. The study claims that with the addition of the NPT Line, up to 7.7 TWh of energy could be delivered to ISO-NE in 2015. This amount could increase to as much as 8.9 TWh by 2024 due to a planned expansion of hydro-electric generation. Finally, the study asserts that the NPT Line would displace fossil-fueled generation and provide fuel diversity benefits.[25]

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[22] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

[23] Northern Pass states that this cost savings is a result of displacing high-cost fossil-fired generation.

[24] Filing at App. G, Exhibit No. NPT-700 (providing a report by Charles River Associates, Inc. regarding congestion reduction benefits of the NPT Line) (CRA Report).

[25] *Id.* at 3.

b. Commission Determination

26. Northern Pass does not claim that it qualifies for the rebuttable presumption under Order No. 679 with respect to ensuring reliability or reducing the cost of delivered power by reducing congestion. Rather than relying on that rebuttable presumption, Northern Pass submitted the above-noted study of congestion mitigation impacts of the NPT Line and resulting price reductions in New England that quantifies the effect of adding the line on LMP throughout the region. Based on our analysis of Northern Pass's study, we find that the NPT Line satisfies this section 219 requirement. Northern Pass's study provides a sufficient basis to conclude that the NPT Line will reduce congestion between Quebec and New England and facilitate integration and delivery of low-cost hydro-electric power. In addition, we find that with the addition of hydro-electric power to the base case, the existence of the NPT Line will help mitigate overloads.

2. The Nexus Requirement

27. In addition to satisfying the section 219 requirement of ensuring reliability and/or reducing the cost of delivered power by reducing congestion, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[26] The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

28. As part of this evaluation, the Commission has found the question of whether a project is routine to be particularly probative.[27] In *Baltimore Gas and Electric Co.*, the Commission clarified how it will evaluate projects to determine whether they are routine. Specifically, the Commission will consider all relevant factors presented by an applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., improving reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead

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[26] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[27] *Baltimore Gas and Electric Co.*, 120 FERC ¶ 61,084, at P 48, *order granting incentive proposal*, 121 FERC ¶ 61,167 (2007), *reh'g denied*, 122 FERC ¶ 61,034, *reh'g denied*, 123 FERC ¶ 61,262 (2008).

times, regulatory and political risks, specific financing challenges, other impediments).[28] Additionally, the Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has shown, for purposes of the nexus test, that the project faces risks and challenges that merit an incentive."[29]

a. Proposal

29. Northern Pass states that there is a nexus between its requested incentives (an ROE of 12.56 percent, the termination rights, and the establishment of a regulatory asset) and the risks and challenges it faces in developing the NPT Line. Northern Pass also states that the NPT Line is non-routine due to its scope, in terms of cost and size, and its effects. In addition, Northern Pass states that the NPT Line faces siting, financial, and technological risks and challenges.[30]

30. With respect to scope, Northern Pass maintains that the NPT Line is a large-scale transmission project; is readily distinguishable from other transmission projects or upgrades that are constructed in the ordinary course of a utility's transmission service obligation to provide safe, reliable service to its customers; and in dollar terms, is among the largest transmission projects in New England. Northern Pass explains that the NPT Line will be the largest transmission project constructed in New Hampshire since the existing HVDC transmission tie was constructed in the 1980s. Northern Pass states that the NPT Line will affect 31 cities and towns and will take six to seven years (counting from the beginning of the development process in 2009) to design, plan, permit, and build.[31]

31. Northern Pass also maintains that from an electrical perspective the NPT Line is large by any standard. Northern Pass states that the construction of this project will vastly expand the New England transmission system's ability to transfer power from low carbon, predominantly hydro-electric power to load, enhancing the performance and reliability of the existing transmission system.[32] Further, Northern Pass states that the

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[28] Filing at 52-55.

[29] *Id.* at 54.

[30] *Id.* at 45-46 and App. G, Ex. No. NPT-700 at 1.

[31] *Id.* at 50.

[32] *Id.* at 51.

NPT Line is significant in terms of both its scale and its costs because it will require construction of approximately 180 miles of new extra high voltage transmission lines in the United States (140 miles of new 300 kV HVDC transmission lines and 40 miles of 345 kV AC transmission lines) and may also require improvements to the existing AC transmission system as a result of the I.3.9 process.[33]

32. With respect to the project's effects, Northern Pass states that the NPT Line is non-routine because it is not a typical reliability project.[34] Instead, the NPT Line is a large-scale regional transmission project to enhance the capability of the New England transmission system to advance regional and national energy policy by allowing for the delivery of substantial quantities of hydro-electric power from Québec, Canada.[35]

33. Northern Pass states that the NPT Line will make available up to 1,200 MW of previously unavailable power from Québec, thus lowering electricity prices in New England, improving reliability, and promoting important environmental goals.[36]

34. With respect to risks and challenges that make the NPT Line a non-routine project, Northern Pass identifies siting, financial, and technological risks and challenges. Northern Pass states that the NPT Line faces a unique level of siting and permitting risks because the construction of the NPT Line is subject to approval by federal[37] and state[38] authorities.

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[33] *Id.*

[34] *Id.*

[35] *Id.* at 52.

[36] *Id*. at CRA Report at 1-2 and App. B, Exh. No. NPT-200 at 16-22.

[37] *Id*. at 53-54. At the federal level, Northern Pass states it must obtain a Presidential Permit and have an Environmental Impact Statement developed by the U.S. Department of Energy (DOE). Northern Pass states that it may also need to obtain permits or approvals from the U.S. Forest Service, the U.S. Fish and Wildlife Service, the Army Corps of Engineers, and the Federal Aviation Administration.

[38] Northern Pass states that the state siting process will consider numerous factors for each project, including alternatives to each of the projects, such as route alternatives, potential environmental and social issues, engineering design, and costs. In New Hampshire, Northern Pass states it must obtain siting approval from the New Hampshire

(continued…)

35. Turning to financial risks and challenges, Northern Pass states that NU and NSTAR's respective shares of the project are a major investment for each company; NU's share is $820 million while NSTAR's share of the NPT Line is $275 million.[39] According to Northern Pass, in recent years NU has been investing large amounts of capital to upgrade its transmission system and will continue to do so in the coming years.[40] Northern Pass states that within this overall program, there will be internal competition for capital funding.[41]

36. Northern Pass also states that it bears a higher level of financial risk relative to a typical transmission project developed and built under the ISO-NE regional planning process because it is a "single-payer" contract, meaning that the success of the contract depends upon the credit and cooperation of one customer. Northern Pass contends that this dependence on one customer is unlike a typical transmission project under the New England regional planning process, where NU and NSTAR would recover their costs from a large class of customers.[42] Northern Pass states that, in this respect, if HQ Hydro and its guarantor were to fail financially, Northern Pass would not have a single committed customer for the NPT Line.[43]

Site Evaluation Committee, which is comprised of members of various state agencies each of which must review the application.

[39] Filing at 51.

[40] For instance, Northern Pass states that for the period 2001 through 2009, NU spent $2.8 billion in new transmission construction. For the period 2011 through 2015, NU is expected to spend the same amount, including the NPT Line. Similarly, Northern Pass states that NSTAR's investment in the NPT Line represents part of an ambitious transmission capital investment program through which it projects to almost double its transmission rate base to approximately $1.6 billion within five years.

[41] Northern Pass states that the large capital expenditures required for the NPT Line will result in significant negative cash flows during the construction period due to the fact that the TSA does not provide for inclusion of CWIP in rate base during the construction period, which distinguishes this participant-funded project from most of the other transmission projects that have received incentive rate treatment under Order No. 679.

[42] Filing at 55.

[43] *Id.*

37. Further, Northern Pass states that under the TSA, HQ Hydro has multiple rights to terminate the TSA and that the risk of customer termination is higher than would exist for a typical transmission project constructed under the ISO-NE regional transmission plan.[44] Northern Pass maintains that while it would be entitled to reimbursement of costs previously incurred upon early termination by HQ Hydro, HQ Hydro would not be required to pay the net present value of the equity return Northern Pass would have received during the remaining balance of the term (i.e., lost opportunity costs) unless HQ Hydro terminates the TSA during the commercial operation phase for convenience.[45] Northern Pass also states that if there is a delay caused by Northern Pass in the commercial operation date of the NPT Line, but the Québec Line is ready for start-up and service, Northern Pass will cease to accrue AFUDC and carrying charges.[46] As a result of these and other provisions, Northern Pass maintains that it is not fully protected against all of its potential losses.

38. Finally, Northern Pass maintains that the NPT Line presents certain risks and challenges associated with the use of advanced technologies. Northern Pass states that the complexity of the NPT Line requires special skill sets for planning, engineering, design, operation, and maintenance of the project. Northern Pass states that the NPT Line employs the following technologies: HVDC technology, optical ground wire, high-temperature conductors, aerial laser survey technology, IEC 61850 Communications Protocols, as well as power electronics and related software. Northern Pass does not, however, request a stand-alone incentive ROE adder based on its proposed use of advanced technology.[47]

b. <u>Commission Determination</u>

39. We find that Northern Pass has sufficiently demonstrated a nexus between the considerable risks and challenges it is undertaking to develop and construct the NPT Line and the incentives it has requested.

40. We find that the NPT Line is not routine based on the project's scope, effects, and the risks and challenges it faces. The scope of the project is significant. The NPT Line is a large-scale international project that involves a 140-mile HVDC transmission line and a

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[44] *Id.* at 56.

[45] *Id.*

[46] *Id.*

[47] *Id*. at App. B, Ex. No NPT-200 at 16-17.

40-mile 345 kV AC transmission line with combined costs estimated at approximately $1.1 billion.[48] The effects of the NPT Line will include making available up to 1,200 MW of hydro-electric power previously unavailable from Quebec.[49] The NPT Line will not only diversify New England's power supply mix, but it will also allow more energy imported from Quebec to be delivered during peak hours when marginal generation costs and market-clearing prices are highest.

41. We also find that Northern Pass faces significant risks and challenges in developing the NPT Line. For example, due to the project being international, Northern Pass must obtain a Presidential Permit from the DOE. Northern Pass must also obtain several other special use permits and a certificate of site and facility from the New Hampshire Site Evaluation Committee. Further, the project will affect 31 cities and towns, require the expansion of some areas of existing rights-of-way, and require the acquisition and development of approximately 50 miles of new rights-of-way.[50] Given the size of the financial commitment required by Northern Pass to complete the project, the NPT Line also presents significant financial risks and challenges.

42. Because we have found that the NPT Line satisfies the requirements of section 219 and the nexus test, we discuss below Northern Pass's request for specific incentives.

3. <u>Incentives</u>

a. <u>Proposed ROE Including Incentive Adders</u>

43. Northern Pass requests an overall ROE of 12.56 percent. Northern Pass submitted both a regional and national proxy group to assist the Commission in arriving at the requested overall ROE. Northern Pass states that an incentive ROE in the upper end of the zone of reasonableness is warranted, and that its requested overall ROE of 12.56 percent is 384 basis points below the upper end of the zone of reasonableness for both the regional and national proxy groups.[51]

44. Northern Pass's expert witness, Dr. Avera, asserts that because an incentive ROE from the upper end of the reasonable DCF range is warranted, there is no need to apply

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[48] *Id.* at 50-51.

[49] *Id.* at 52 and App. B, Ex No. NPT-200 at 16-17.

[50] *Id.* at 52-54 and App. B, Ex. No. NPT-200 at 23-27.

[51] *Id.* at 37.

either the median or the midpoint in setting the ROE.[52] However, Northern Pass states that if the Commission finds it necessary to evaluate the proposed ROE using a reference point within the zone of reasonableness, it proposes a base ROE of 10.4 percent, which is the median[53] of its proposed zone of reasonableness resulting from a national proxy group.[54]

45. To arrive at its proposed base ROE, Northern Pass applied a discounted cash flow analysis to a proxy group of transmission-owning utilities, which it states is consistent with Commission methodology.[55] Northern Pass states that it used a national proxy group,[56] consistent with the approach approved in the *PATH Rehearing Order* where the Commission found that "mere geographic proximity" is not the sole basis for inclusion of companies in a proxy group.[57] Therefore, Northern Pass used a starting sample of 24 predominantly electric utilities.[58] In addition, Northern Pass states that it evaluated its

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[52] *Id*. at Ex. NPT-600 at 45-46.

[53] Northern Pass's request to use the median is contrary to Dr. Avera's testimony, which noted that he would not support or recommend sole reliance on the median to evaluate the ROE for Northern Pass because the median values for the proxy groups of electric utilities produced using the Commission's methodology fall consistently below other measures of central tendency, such as the midpoint. *Id.* at 36-37 and App. F, Ex. No. NPT-600 at 47-51.

[54] *Id.* at 37-38. Northern Pass asserts that a base ROE of 10.4 percent plus its requested incentive ROE adders for RTO participation and new transmission, result in an overall ROE of 12.56 percent that is within its proposed zone of reasonableness.

[55] *Id.* at 34 (citing *Atlantic Path 15, LLC*, 133 FERC ¶ 61,153 (2010) (*Atlantic Path 15*); *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 (2010) (*PATH Rehearing Order*)).

[56] In addition to the national proxy group, Northern Pass submitted analytical support for a regional proxy group, a ratings screen proxy group, and a non-utility proxy group.

[57] Filing at App. F, Ex. NPT-600 at 30.

[58] Northern Pass's proposed national proxy group includes: Ameren Corp., American Electric Power Co. Inc., Avista Corp., Black Hills Corp., CenterPoint Energy, Cleco Corp., CMS Energy, DTE Energy Co., Edison International, Great Plains Energy, Hawaiian Electric, IDACORP, Inc., Integrys Energy Group Inc., ITC Holdings Corp., Pepco Holdings Inc., PG&E Corp., Pinnacle West Capital, Portland General Electric,

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national proxy group through several risk measures, including Standard and Poor's (S&P) corporate credit rating.[59] Because Northern Pass is targeting a credit rating from S&P of BBB, it eliminated utilities with credit ratings more than one rating notch above and below BBB.[60]

46. Northern Pass explains that it included companies in its proxy group that: (1) are currently paying dividends; (2) have an S&P corporate credit rating between BBB- and BBB+; (3) have available Value Line data and IBES growth rate data; (4) have not been recently involved in merger and acquisition activity; and (5) have sustainable growth rates below 13.3 percent.[61] Northern Pass then excluded eight companies from the proxy group because their low-end cost of equity was below or not sufficiently higher than the expected yields on BBB utility bonds, averaging 5.8 percent over the six-month period ending November 2010.[62] In addition, Northern Pass states that it excluded ITC Holdings Corp. and Great Plains Energy because their high-end cost of equity estimates are extreme outliers, consistent with the rationale adopted by the Commission in *Bangor Hydro*.[63]

47. Having established a proposed proxy group and a median ROE of 10.4 percent, Northern Pass requests that, during the construction period and for purposes of accruing AFUDC, the Commission approve the following incentive ROE adders: (1) 50 basis points for participation in a regional transmission organization; and (2) 164 basis points for investment in new transmission facilities. Northern Pass requests that these ROE adders, when added to its base ROE, produce an overall ROE of 12.56 percent.[64]

PPL Corp., Progress Energy, TECO Energy, UIL Holdings, Westar Energy, and Wisconsin Energy Corp. *Id*. at App. F, Ex. NPT-602 at 1.

[59] *Id*. at App. F, Ex. NPT-600 at 30.

[60] *Id*. at App. F, Ex. NPT-600 at 31.

[61] *Id*. at App. F, Ex. NPT-600 at 30.

[62] *Id*. at App. F, Ex. NPT-600 at 42-43.

[63] *Id*. at App. F, Ex. NPT-600 at 44-45 (citing *ISO New England Inc., et al.*, 109 FERC ¶ 61,147, at P 205 (2004)).

[64] Because Northern Pass primarily emphasizes its proposed overall ROE of 12.56 percent, we will interpret its application to request the 166 basis point incentive ROE adder needed to produce that overall ROE.

48. Northern Pass requests that, upon commercial operation, the Commission approve the following incentive ROE adders: (1) 50 basis points for participation in a regional transmission organization; and (2) 92 basis points for investment in new transmission facilities. Northern Pass requests that these ROE adders, when added to the base ROE under the ISO-NE OATT to which Northern Pass states it would be entitled (currently 11.14 percent), again produce an overall ROE of 12.56 percent.[65]

b. Protest

49. No parties protested the proxy group make-up or the results of the discounted cash flow analysis. However, NEPGA argues that, as a general matter for ISO-NE, the Commission previously rejected a proposal by the Transmission Owners for 50 and 100 basis point adders for Local Network Service (LNS) facilities, but accepted the 50 and 100 basis point adders for Regional Network Service. NEPGA states that, at best, Northern Pass's facilities are radial facilities that comprise what equates to LNS facilities because the radial facilities are not pool transmission facilities (PTF) under existing ISO-NE OATT provisions.[66]

50. NEPGA argues that if the Commission were to grant these incentives, it would open the door for utilities to seek incentive rate treatment for any radial, non-network transmission line. Therefore, NEPGA argues that the Commission should reject the proposed incentive rate treatment.[67]

c. Answers

51. In response to NEPGA's opposition to incentive rate treatment for the NPT Line, Northern Pass states that, contrary to NEPGA assertions, no Commission rule or order would prevent a transmission owner from requesting incentive treatment for local, non-PTF facilities in New England. Northern Pass states that the NPT Line is one of the largest transmission projects in New England and is not "routine" in the sense that the Commission has used the term in connection with its implementation of Order No. 679. Indeed, Northern Pass argues that the Commission has approved Order No. 679 incentives for projects that are similar to the NPT Line – i.e., long distance, high capacity

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[65] *Id.* at 6, 41-42.

[66] NEPGA Protest at 8-9.

[67] *Id.* at 9.

transmission lines providing load centers with access to low carbon generation resources.[68]

d. Commission Determination

52. The Commission finds that the 24 companies identified by Northern Pass are an appropriate starting point for developing a proxy group that reflects comparable risks. While geographic proximity may be a relevant factor in identifying companies with comparable risks, it is not the sole basis for inclusion of companies in a proxy group.[69] The Commission also finds that the corporate credit rating screen that Northern Pass used is consistent with Commission precedent.[70]

53. However, the Commission finds that Northern Pass improperly removed Edison International, Great Plains Energy, Hawaiian Electric, and Integrys Energy Corp. from the final proxy group due to their low end cost of equity being at or below 7.5 percent. The Commission finds that a company should be eliminated from the final proxy group only if its low end cost of equity is about 100 basis points above the cost of debt.[71] Thus, the Commission will exclude from the proxy group those companies whose low-end ROE is about 100 basis points above the cost of debt, taking into account the extent to which the excluded low-end ROEs are outliers from the low-end ROEs of other proxy group companies.[72] Here, not only are Edison International's, Great Plains Energy's, Hawaiian Electric's, and Integrys Energy Corp.'s low-end ROEs more than 100 basis points above Moody's BBB bond yield, but they also do not appear to be significant outliers from the low-end ROEs of the other companies that remain in the proxy group, unlike the low-end

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[68] Northern Pass Answer at 9-10 (citing *S. Cal. Edison Co.*, 121 FERC ¶ 61,168 (2007); *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009); *Pac. Gas and Elec. Co.*, 123 FERC ¶ 61,067 (2008)).

[69] *PATH Rehearing Order*, 133 FERC ¶ 61,152 at P 60.

[70] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 95 (*PATH*). While Northern Pass has proposed Value Line's Safety Rank and Financial Strength Rating, the Commission finds the use of the corporate credit rating to be sufficient.

[71] Moody's monthly yields on BBB utility bonds average 5.8 percent over the six-month period ending November 2010.

[72] *Pioneer Transmission LLC,* 126 FERC ¶ 61,281, at 94 (2009), *reh'g denied,* 130 FERC ¶ 61,044 (2010).

ROEs of the four companies we are excluding from the proxy group.[73] We agree with Northern Pass that Ameren Corp., Black Hills Corp., Cleco Corp., and Pepco Holdings, Inc should be excluded from the proxy group because their low-end ROEs are not sufficiently above the cost of debt.[74] The Commission concludes that Northern Pass has failed to show that the low-end ROEs of Edison International, Great Plains Energy, Hawaiian Electric, and Integrys Energy Corp. are so low as to require the exclusion of those companies from the proxy group.[75] As a result of adding these companies to the proxy group, the low end ROE is reduced but the median remains unchanged.

54. Accounting for these changes, we conclude that Northern Pass's base ROE for pre-commercial operation should be 10.4 percent, which is the median of the proxy group adopted in this order.[76] We also find that, as Northern Pass requests, Northern Pass will be entitled to the base ROE under the ISO-NE OATT (currently 11.14 percent) upon commercial operation of the NPT Line and transfer of operational control of the line to ISO-NE.

55. We grant Northern Pass's request for a 50 basis point incentive ROE adder to reflect its participation in ISO-NE. Northern Pass's request is consistent with past incentives that the Commission has granted to reflect an applicant's participation in an RTO or ISO.[77]

56. Additionally, based on the unique nature of Northern Pass's project and the unique commercial arrangements facilitating its construction, we will also grant Northern Pass's request for a 166 basis point incentive ROE adder during pre-commercial operation to arrive at an overall ROE of 12.56 percent. As discussed above, Northern Pass has shown a nexus between the requested incentives and the risks and challenges of the NPT Line.

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[73] Edison International, Great Plains Energy and Integrys Energy Corp. have low-end ROEs of 7.1 percent while Hawaiian Electric has a low-end ROE of 7.5 percent.

[74] Ameren Corp., Black Hills Corp., Cleco Corp., and Pepco Holdings, Inc.'s low-end ROEs are the following: 1.5 percent, 6.2 percent, 6.3 percent, and 6.5 percent, respectively.

[75] Great Plains Energy was eliminated from the final proxy group due to its high end cost of equity being an extreme outlier.

[76] *See PATH Rehearing Order,* 133 FERC ¶ 61,152 at P 65.

[77] *See, e.g., S. Cal. Edison Co.,* 133 FERC ¶ 61,107 (2010); *S. Cal. Edison Co.,* 133 FERC ¶ 61,108 (2010).

For example, Northern Pass faces the difficult task of securing several permits (including a Presidential Permit from DOE), certificates, and rights-of-way. The NPT Line also presents significant financial risks and challenges. The Commission recognizes that this project is a major undertaking by both NU and NSTAR. Specifically, the $1.1 billion capital commitment will significantly add to both companies' average transmission project investment.[78] The 166 basis point adder will help Northern Pass attract capital investment that will make it more likely that the project will be constructed.

57. Northern Pass's commitment to having none of the costs of the NPT Line or any ISO-NE-required or HQ Hydro-requested upgrades associated with the TSA included in any rates charged under the ISO-NE OATT to regional and local customers also weighs in our decision to grant the ROE adder. [79] The TSA obligates HQ Hydro to pay 100 percent of the capital and operating costs of the NPT Line and of any upgrades under the TSA. Therefore, no New England customers will be compelled to purchase Hydro-Quebec power delivered over the NPT Line at an above-market price.[80]

58. Upon commercial operation of the NPT Line, we will similarly grant Northern Pass the requested 92 basis points incentive ROE to bring its overall ROE to 12.56 percent. We note that Northern Pass requested this reduction in its incentive ROE adder, corresponding to an increase in its base ROE when it joins ISO-NE and receives the base ROE under the ISO-NE OATT.

57. We disagree with NEPGA's position that the Commission should grant incentives only for Regional Network Service facilities in ISO-NE. We consider each case on an individual basis and are not persuaded by NEPGA's protest that the requested incentive ROE adders are not appropriate because the NPT Line is a radial facility. The proposed project faces significant risks and challenges, as discussed above, and the Commission finds that those factors support these requested incentives.

4. <u>Termination Rights</u>

a. <u>Proposal</u>

58. Northern Pass states that the NPT Line faces numerous uncertainties, and the parties have negotiated and agreed to certain termination rights and the parties' cost

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[78] Filing at App. C, Ex. No. NPT-300 at 10-11.

[79] Filing at 7-8.

[80] *Id.* at 8-9.

responsibilities should those termination provisions be exercised. Northern Pass states that, under section 3 of the TSA, the parties have the right to terminate the TSA during the development phase, the construction phase, or following commercial operation. In addition, Northern Pass states that HQ Hydro may terminate the TSA for convenience. Northern Pass states that, under the TSA, it will have the right to recover the costs it has already incurred, including AFUDC, if the NPT Line were to be abandoned under the circumstances set forth in the TSA. Northern Pass maintains, however, that it will lose the right to recover a return on its anticipated equity investment in the project, a substantial lost opportunity cost.

59. Northern Pass requests that the TSA termination provisions be characterized as eligible for the abandoned plant cost recovery incentive under Order No. 679. Northern Pass contends that the Commission has recognized that "the recovery of abandonment costs is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs."

b. Commission Determination

60. We find that Northern Pass has demonstrated a nexus between the risks and challenges of the project and the opportunity to recover costs as provided in the termination rights provisions of the TSA. As we have emphasized in other proceedings,[81] recovery of abandoned plant costs in appropriate circumstances is an effective means to encourage transmission development by reducing the risk of non-recovery of costs. Accordingly, we accept the termination rights provisions of the TSA without modification.

5. Regulatory Asset

a. Proposal

61. Northern Pass seeks authorization to establish a regulatory asset for certain costs that it has incurred and will continue to incur prior to the NPT Line's commercial operation date that do not meet the requirements to be included in CWIP. Northern Pass maintains that, under the TSA, the parties have agreed that Northern Pass's recovery of such costs will be deferred until the project enters commercial operation and then will be recovered from HQ Hydro through the formula rate. Northern Pass explains that such costs exclude TSA negotiation costs, but may include the costs of AC upgrades billed to Northern Pass prior to the commercial operation date by third parties constructing such

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[81] *See PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 47 (2008); *S. Cal. Edison Co.*, 121 FERC ¶ 61,168 at P 72.

upgrades, and routine costs associated with Northern Pass during this period, such as accounting, cash management, and other administrative costs. Northern Pass states that it proposes to amortize this regulatory asset over a three-year period commencing on the commercial operation date of the project.[82] Northern Pass asserts that the establishment of this regulatory asset will allow it to recover those costs that are incurred prior to the commercial operation date and is consistent with regulatory assets approved by the Commission in other Order No. 679 proceedings.[83]

62. Northern Pass also seeks Commission authorization, to the extent necessary, to record a regulatory asset for the expenses related to an asset retirement obligation (ARO) created for the decommissioning of the NPT Line. Northern Pass explains that the TSA provides for the recovery of the estimated costs to decommission the NPT Line over the last five years of the 40-year term of the TSA. Northern Pass does not believe the establishment of this regulatory asset is an incentive under Order No. 679.[84]

b. Commission Determination

63. The Commission grants Northern Pass's request for authorization to establish the regulatory asset. Granting this incentive will allow Northern Pass to defer recovery of pre-construction costs, as well as start-up and development costs, and recover them later. The Commission finds the incentive is tailored to Northern Pass's risks and challenges because this incentive will provide it with added up-front regulatory certainty and can reduce interest expense, improve coverage ratios, and facilitate the financing of the NPT Line on reasonable terms. Granting this incentive encourages increased development of transmission infrastructure, thereby fulfilling the goals of FPA section 219.[85]

64. Northern Pass must record the regulatory asset for pre-commercial costs in Account 182.3, Other Regulatory Assets, and may only include amounts that otherwise would be chargeable to expense in the period incurred, are not recoverable in current rates, and are probable for recovery in rates in a different period.[86] Northern Pass may

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[82] Filing at 63.

[83] *See ITC Great Plains*, 126 FERC ¶ 61,223, at P 74 (2009); *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058, at P 99 (2006).

[84] Filing at 11 n.11.

[85] *See, e.g., Green Power Express LP*, 127 FERC ¶ 61,031, at P 61 (2009).

[86] The term "probable" as used in the definition of regulatory assets, refers to that which can reasonably be expected or believed on the basis of available evidence or logic

(continued…)

also record a regulatory asset for the ARO expenses related to the decommissioning of the NPT Line in Account 182.3. The instructions to Account 182.3 require that amounts deferred in this account are to be charged to expense concurrent with the recovery of the amounts in rates. If rate recovery of all or part of the costs deferred in Account 182.3 is later disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, in the year of disallowance.

C. Other Issues

1. Unused Capacity

a. Proposal

65. The TSA states that Northern Pass will make available to HQ Hydro firm transmission service on the NPT Line up to 1,200 MW, together with, on a non-firm basis, any additional transmission service that is incidental to the design, engineering, construction or operation of the NPT Line. In addition, if HQ Hydro determines that the transmission capacity of the NPT Line exceeds HQ Hydro's needs, the TSA states that HQ Hydro will offer to sell such unused capacity in accordance with applicable law, including Order No. 890. Any capacity on the NPT Line not scheduled by HQ Hydro by the applicable scheduling deadline for the following day is to be made available for resale to third parties through an OASIS site. The parties agree to jointly contract with independent, non-affiliated third parties for use of an OASIS site.[87]

b. Protest and Comments

66. NEPGA states that the TSA improperly interferes with future third-party transmission rights in contravention to the Commission's May 22 Order and long-standing policies under the FPA. In particular, NEPGA argues that the parties to the TSA effectively claim a right to allow existing transmission capacity to lie fallow until HQ Hydro needs to use it,[88] which, according to NEPGA, conflicts with Commission

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but is neither certain nor proved. *Revisions to Uniform Systems of Accounts to Account for Allowances under the Clear Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2, and 2-A*, Order No. 552, 62 FERC ¶ 61,299 (1993) .

[87] HQ Hydro Answer at 8.

[88] NEPGA Protest at 5 (citing TSA §§ 7.1.3 and 10.1).

precedent[89] and section 211 of the FPA. NEPGA asks the Commission to require Northern Pass to file, within 60 days of the receipt of a request for interconnection or transmission service, an OATT to provide for service to third parties. It further seeks clarification that, in accordance with *Aero Energy* and the May 22 Order, HQ Hydro cannot retain its firm transmission rights over the line if such transmission capacity goes unused.

c. <u>Answers</u>

67. Northern Pass states in its answer that NEPGA misunderstands the provisions of the TSA governing the resale of unused transmission capacity. Northern Pass clarifies that under section 10.1, Northern Pass has the right to determine on a going-forward basis if there is capacity available over the NPT Line that it does not need for its own use. Section 10.2 requires that, if HQ Hydro does not schedule transactions using the full transmission capacity of the NPT Line by the applicable ISO-NE scheduling deadline, the unused transmission capacity must be released for resale to third parties for daily and hourly transactions on the following day. Such unused capacity must then be posted on an OASIS site for resale under section 10.3. Thus, section 10 of the TSA provides for the mandatory posting and resale of unused transmission capacity over the NPT Line whenever HQ Hydro has not scheduled transactions using its full capacity rights, which is in compliance with the Commission's directive in the May 22 Order that unused capacity be made available to third parties pursuant to Order No. 890.

68. Northern Pass and HQ Hydro both argue that *Aero Energy* is inapposite, as that case involved unused firm transmission capacity, while here HQ Hydro has purchased the entire 1,200 MW of firm capacity on the line and has not generically reserved capacity for unknown future use or development. Accordingly, unlike *Aero Energy*, the only potentially relevant resale issue in the instant case involves the resale obligation of the purchaser, HQ Hydro, and not any obligation that Northern Pass would have to sell transmission service on an open access basis. HQ Hydro clarifies that its rights as a firm transmission customer under Order No. 890 to make business decisions as to when it may have excess capacity is preserved, while at the same time the ability of third parties to access capacity that is actually available and unused on any day or any hour is guaranteed to be handled in a fair and independent manner under the TSA.[90]

69. HQ Hydro responds that NEPGA has misread the manner in which the TSA deals with unused capacity. It states that, under Order No. 890's open access principles, there

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[89] *See Aero Energy LLC*, 116 FERC ¶ 61,149 (2006) (*Aero Energy*).

[90] HQ Hydro Answer at 6.

are no established standards by which a firm transmission customer must make the capacity for which it holds a firm service agreement (and for which it is paying full tariff amounts) available to other parties when it does not use all of its capacity. Moreover, it notes that the TSA provides that any capacity that is unused by HQ Hydro during any hour of any day during the term of the TSA will be offered automatically to third parties by means of an OASIS posting, and the pricing of such capacity will be determined by independent third parties.

d. Commission Determination

70. We find that the TSA does not improperly interfere with future third party transmission rights. As discussed more fully below, HQ Hydro, as the entity participant-funding the project, is permitted to receive priority rights to use the facility. Furthermore, we find that the TSA properly commits to make available any unused transmission capacity.

71. NEPGA's first concern pertains to the availability to third parties of additional capacity that is incidental to the design, engineering, construction or operation of the NPT Line. Specifically, NEPGA protests section 7 of the TSA, in which HQ Hydro retains the right of first refusal for any non-firm "incidental" capacity over the 1,200 MW of contracted capacity.[91] As the Commission found in the May 22 Order, providing for participant funding of a transmission facility and, in return, receiving priority rights to use that facility is fully consistent with long-standing open access policies and does not constitute undue preference or discrimination.[92] Therefore, we disagree that section 7 of the TSA contravenes Commission policy. HQ Hydro, as the entity paying the costs of the project, may retain priority rights over the transmission capacity of the line, including the incidental capacity above the contracted capacity. These priority rights do not constitute undue preference or discrimination.

72. NEPGA further protests the TSA's treatment of unused capacity in the event that HQ Hydro's 1,200 MW of capacity exceeds its needs. On this issue, NEPGA has particular concern with section 10 of the TSA, which NEPGA argues will give HQ Hydro sole discretion in determining whether to offer to resell available capacity over the line

[91] Section 7.1.1 of the TSA states that Northern Pass will provide HQ Hydro with non-firm transmission service for any "incidental" transmission capacity above 1,200 MW. Section 7.1.3 of the TSA states that Northern Pass has no other obligation to provide transmission service other than to HQ Hydro for the contracted 1,200 MW of firm capacity and the non-firm incidental capacity above 1,200 MW.

[92] May 22 Order, 127 FERC ¶ 61,179 at P 27.

that exceeds its needs.[93] We agree with NEPGA that any unused transmission capacity must be made available pursuant to the requirements of Order No. 890 and the ISO-NE OATT. However, we disagree with NEPGA's interpretation of the TSA in this regard. Section 10 of the TSA, as clarified in the answers of Northern Pass and HQ Hydro, provides that, while HQ Hydro will retain the discretion to determine whether it has unused capacity during the scheduling period, any capacity not scheduled by the applicable scheduling deadline must be offered for resale to third parties through OASIS.[94] Thus, while HQ Hydro can make the initial business decision with respect to whether it should enter into bilateral agreements with third parties for capacity that it does not plan to use in the future, any capacity that is actually unscheduled by HQ-Hydro during any hour of any day during the term of the TSA will be offered automatically to third parties by means of an OASIS posting. The TSA further requires Northern Pass and HQ Hydro to contract with independent, non-affiliated third parties for use of an OASIS site and to carry out capacity release functions for daily and hourly re-sales.[95] We find that these provisions sufficiently ensure that all unused capacity will be made available pursuant to the relevant open access requirements.

2. Rate Treatment for the NPT Line

a. Proposal

73. Northern Pass states that in order to interconnect the proposed HVDC Line with the bulk power system in New England in a reliable manner, it has determined (and HQ Hydro has agreed) that it must construct an approximately 40-mile, 345 kV, radial AC Line extending from the southern end of the HVDC Line to an existing PSNH substation.

74. With respect to the AC Line, Northern Pass states that the parties to the TSA have taken into consideration the possibility that ISO-NE may require certain modifications or reinforcements to AC network transmission facilities in New England in order to satisfy the requirements of Section I.3.9 of the ISO-NE Services Tariff. Northern Pass maintains that this section requires ISO-NE to conduct an evaluation of the impacts of any new

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[93] *See* Filing at App. A, Ex. No. NPT-100 at TSA §10.1 ("If and to the extent Purchaser determines from time to time, and in its sole discretion, that the transmission capacity available over the NPT Line exceeds Purchaser's needs, Purchaser shall then offer to resell such unused capacity to third parties in accordance with Applicable Law . . . ").

[94] *Id.* at TSA §10.3.

[95] *Id.*

transmission facility rated 69 kV or above on the stability, reliability or operating characteristics of the network. On October 13, 2010, Northern Pass filed an application with ISO-NE for review of the NPT Line under Section I.3.9.[96] Northern Pass contends that, to the extent that ISO-NE determines that other AC upgrades are required, the TSA provides that HQ Hydro will be responsible for the costs thereof through the formula rate.

b. Protest and Comments

75. NEPGA objects to Northern Pass's and HQ Hydro's proposal to treat the 40-mile radial 345 kV line as a PTF by ISO-NE and potentially include it in rolled-in regional rates.[97] NEPGA states that Northern Pass is a participant-funded, radial transmission project and that neither the HVDC nor AC portion should be "considered an elective network upgrade or a [PTF] and would therefore not fit under existing ISO-NE OATT provisions."

76. NEPGA maintains that while the TSA provisions provide an opportunity for HQ to request roll-in of a portion of the NPT Line costs into the pool-supported PTF, the ISO-NE OATT, Schedule 12 B(2) and the ISO-NE tariff definition very clearly state that this option does not exist.[98]

77. NEPGA asserts that TSA sections 8.6(b), (c), (e), and (f) are inconsistent with the ISO-NE Services Tariff provisions applicable to all other Elective Upgrade investments. According to NEPGA, the ISO-NE Services Tariff provides only one choice: Elective Transmission Upgrade costs are never rolled into Pool-Supported PTF costs and are allocated "to the entity or entities volunteering to make and pay for such Elective

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[96] December 29 Order, 129 FERC ¶ 61,279 at P 48 (citing May 22 Order, 127 FERC ¶ 61,179 at P 63).

[97] *See* App. A, Ex. No. NPT-100 at TSA § 8.6(b).

[98] ISO-NE OATT, Schedule 12 B(2) states in whole, "The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades." ISO-NE Services Tariff, Section I, definitions at 63. Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Transmission Upgrades." In return, NEPGA maintains that the entity volunteering to make such payments receive the financial transmission rights created by such upgrades. NEPGA states that these sections of the TSA should be modified to be compliant with the ISO-NE Services Tariff.

c. Answers

78. Northern Pass argues that NEPGA has misconstrued the TSA. Northern Pass states that the customer, HQ Hydro, will pay for all of the costs related to the project.[99] It maintains that, as a radial facility necessary to interconnect the HVDC facilities with the regional network, the AC Line is part of the NPT Line and will be paid for by HQ Hydro under the TSA. In addition, according to Northern Pass, HQ Hydro is responsible for the cost of any AC upgrades that ISO-NE determines to be necessary to reliably interconnect the NPT Line to the system pursuant to section I.3.9 of the ISO-NE Services Tariff.[100]

79. Northern Pass contends that the TSA has a 40-year term and that TSA section 8.6 simply contemplates possible future circumstances where the parties may wish to request that ISO-NE include the AC Line in regional rates, if such an action would be appropriate under the ISO-NE OATT, and consistent with the cost recovery treatment of other PTF facilities in New England.

80. Northern Pass asserts that section 8.6(b) is clear that including the AC Line in regional rates can occur only if the AC Line becomes a network transmission facility that is eligible to be categorized as PTF, and if ISO-NE then approves regional cost recovery for the AC Line. If this change occurs, according to Northern Pass, then the TSA provides that it may transfer ownership of the PTF portion of the AC Line to its affiliate, PSNH. In connection with any such transfer of ownership to PSNH, Northern Pass states it would enter into an agreement with PSNH under which Northern Pass would pay all of PSNH's costs and expenses associated with the transferred facilities and it would recover these payments under the TSA formula rate; HQ Hydro would then be able to ask the owner of the AC Line to submit a request to ISO-NE that the AC Line should be included in regional rates.

81. Northern Pass emphasizes that section 8.6 does not confer unilateral cost inclusion rights on Northern Pass, PSNH, or HQ Hydro, acting individually or collectively, because it recognizes that ISO-NE would make the ultimate determination on regional cost allocation if future system upgrades create a circumstance where the AC Line becomes a

[99] *See* December 29 Order, 129 FERC ¶ 61,279 at P 3.

[100] Filing at 5, 7-8, 19-20.

network facility providing a regional benefit. Northern Pass maintains that if ISO-NE determined that roll-in would be appropriate, the AC Line would be treated like all other network transmission facilities paid for by load, and HQ Hydro would no longer be entitled to congestion revenues associated with deliveries over the applicable network facilities. Northern Pass states that, at this time, whether ISO-NE will make a future determination that roll-in of the AC Line's costs would be appropriate, the circumstances upon which such a determination would be made, or even whether NEPGA in the future would object to such a future determination, are not known. However, according to HQ Hydro, the TSA must contemplate changes that may occur over a 40-plus year period, and it maintains that the purpose of this section from its standpoint is not to propose a roll-in of costs, but to ensure that the its rights, relating to this line, are at all times aligned with its cost responsibilities.

d. Commission Determination

82. We find that it is premature for parties to contest whether the cost of the AC Line or any upgrade will be rolled into regional rates. At present, HQ Hydro is responsible for all costs associated with the NPT Line, and there will be no impact on the rates for transmission service under the ISO-NE OATT. To be rolled into regional rates, ISO-NE must first determine that the cost of the line or any upgrades should receive regional rate treatment. If ISO-NE makes this determination and parties object to rolling the costs of the project into the regional rates, they can raise those concerns at that time. For these reasons, we accept Northern Pass's rate treatment for the NPT Line. Therefore, we reject NEPGA's protest on this issue.

3. Access to Information on Possible Greater Boston Area Upgrades

83. NEPGA alleges that prior knowledge by NU and NSTAR of the preferred Reliability Upgrades to address North Shore/Boston Massachusetts reliability needs, including a new 345kV line from Scobie, New Hampshire to Tewksbury, Massachusetts, together with related upgrades, may have improperly affected the TSA negotiations. NEPGA states that this knowledge may have benefited the Northern Pass TSA negotiations, as well as HQ Hydro's willingness to pay a premium ROE under the TSA and the valuation of such a premium.

84. NEPGA requests that the Commission direct ISO-NE to provide an exceptionally high level of scrutiny to any determinations that the Scobie-Tewksbury line and related Reliability Upgrades are truly necessary, and that they represent the best, least-cost solutions to local problems independent of Northern Pass. NEPGA asks the Commission to allocate any regionally-socialized transmission costs requested by Northern Pass to the benefiting transmission owner and not to the region as a whole.

85. Northern Pass answers that these arguments have no merit. Northern Pass states that NU and NSTAR have not transferred non-public information regarding the Scobie-Tewksbury upgrades to HQ Hydro. Northern Pass also responds to NEPGA that the NPT Line and the Scobie-Tewksbury upgrades are independent projects that are being considered separately by ISO-NE.

86. HQ Hydro answers that NEPGA's claim has no merit, because the Scobie-Tewksbury line has been the subject of discussion multiple times since at least 2008 in meetings open to all ISO-NE stakeholders. These meetings were held by the Planning Advisory Committee of ISO-NE as part of its regional planning process. HQ Hydro states that it participates in this process and received information at the same time as other stakeholders.

87. ISO-NE responds to NEPGA's claim and states that the Reliability Upgrades were developed in an open and transparent manner that included several presentations to the Planning Advisory Committee and inclusion of the Reliability Upgrades in the ISO-NE Regional System Plan. ISO-NE states that it has been studying the need for upgrades in the Greater Boston area for years and has been working through the open and transparent stakeholder process. Through this process, ISO-NE states that it has identified potential transmission solutions, including the Scobie to Tewksbury upgrades. ISO-NE notes that a discussion of the potential solutions, including the Scobie to Tewksbury upgrades, was presented at the March 18, 2010 Planning Advisory Committee meeting attended by numerous market participants, including many NEPGA members and other potential developers. ISO-NE further states that the December 16, 2010 Planning Advisory Committee presentation that NEPGA references in its protest as the first revelation of the Scobie to Tewksbury project was actually an update from the March 18, 2010 Planning Advisory Committee meeting, which showed the Scobie to Tewksbury option as the "preliminary preferred" option for technical, feasibility, and cost reasons. ISO-NE states that it expects to present a finalized solution addressing all the needs identified in the Greater Boston Needs Assessment to the Planning Advisory Committee by the end of 2011.

88. In response to NEPGA's claim that the reliability need for the Scobie to Tewskbury line is tied to the proposed NPT Line, ISO-NE provides that the Scobie to Tewksbury line is designed to address specific reliability needs identified in the planning process. The reliability needs identified in the Greater Boston Needs Assessment are in response to violations of NERC, NPCC, and ISO-NE criteria and that these violations are independent and completely separate from the NPT Line.

89. The Commission denies NEPGA's request to direct ISO-NE to provide an exceptionally high level of scrutiny to any determinations for the Scobie-Tewksbury line and to order any specific allocation of costs because NEPGA has failed to provide enough information to warrant such a direction from the Commission. Northern Pass,

HQ Hydro, and ISO-NE all provide factual support disputing the allegations made by NEPGA. Further, HQ Hydro affirmatively states that it received information at the same time as other stakeholders.

4. Environmental Review

90. Meriden Hill contends that the NPT Line will adversely affect its members' use and enjoyment of their properties, and that construction of the NPT Line would create adverse environmental impacts. Meriden Hill asks the Commission to consider the impact this project will have on the environment surrounding the project with the understanding that environmental review is being conducted as part of the Presidential Permitting process with the DOE.

91. In its answer, Northern Pass argues that the Commission has consistently, and properly, found that environmental issues are outside the scope of FPA section 205 proceedings.[101]

92. We agree with Northern Pass that the environmental issues raised by Meriden Hill are outside the scope of our review of the TSA.[102] Therefore, the Commission declines to consider the environmental concerns raised by Meriden Hill here.

5. Issues Related to Hydro-Québec

93. Meriden Hill requests that the Commission hold hearings and permit discovery with respect to certain issues related to Hydro-Québec's status as a foreign corporation, including possible foreign control of eminent domain power, ability to set prices, and a lack of jurisdiction by the Commission.

94. HQ Hydro answers that Meriden Hill's comments lack support, misunderstand or mischaracterize the TSA, and misrepresent the issues properly before the Commission. First, HQ Hydro states that it is a U.S. corporation established to market electric power and related products in wholesale electric markets in the United States, and therefore it is subject to the same jurisdiction as any other jurisdictional power marketers. Second, HQ Hydro proposes to sell almost all of its power into the organized markets in ISO-NE. Third, HQ Hydro states that it is the transmission customer under the proposed TSA, and

[101] Northern Pass Answer at 16.

[102] *See, e.g.*, *Monongahela Power Co.*, 39 FERC ¶ 61,350, at 62,096 (1987) (noting that Congress has not granted the Commission authority to reject rate filings on environmental grounds).

is no different than any other long-term, firm transmission customer under the Commission's open access rules.

95. Northern Pass answers that none of the concerns raised by Meriden Hill are relevant to the justness and reasonableness of Northern Pass's sale of transmission services under the TSA. Northern Pass also states that the Commission has never attempted to limit the ability of foreign entities to sell power competitively into the United States, and the Presidential Permit process demonstrates that there is no executive or legislative policy in opposition to such sales.

96. We agree with both Northern Pass and HQ Hydro that the issues raised by Meriden Hill lack merit and misunderstand the structure of the proposal, the identification of the parties to the TSA, and the Commission's jurisdiction over the parties. For these reasons, we decline to set these issues for hearing.

The Commission orders:

The TSA is hereby accepted for filing, effective February 14, 2011, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Tariff Submitter: Northern Pass Transmission LLC
FERC Tariff Program Name: FERC FPA Electric Tariff
Tariff Title: FERC Tariffs
Tariff Record Proposed Effective Date: February 14, 2014
Tariff Record Title: Rate Schedule No. 1
Version 1.0.0
Option Code: A

TRANSMISSION SERVICE AGREEMENT

by and between

NORTHERN PASS TRANSMISSION LLC,

as Owner

and

HYDRO RENEWABLE ENERGY INC.

(f/k/a H.Q. HYDRO RENEWABLE ENERGY, INC.),

as Purchaser

Original Execution Date: October 4, 2010

Effective Date: February 14, 2014

TRANSMISSION SERVICE AGREEMENT

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NORTHERN PASS TRANSMISSION LLC,

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and

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(f/k/a H.Q. HYDRO RENEWABLE ENERGY, INC.),

as Purchaser

Dated: October 4, 2010

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TRANSMISSION SERVICE AGREEMENT

This TRANSMISSION SERVICE AGREEMENT (this "Agreement"), dated as of October 4, 2010 (the "Execution Date"), is made and entered into by and between Northern Pass Transmission LLC, a limited liability company organized and existing under the laws of the State of New Hampshire ("Owner"), and Hydro Renewable Energy Inc. (f/k/a H.Q. Hydro Renewable Energy, Inc.), a corporation organized and existing under the laws of the State of Delaware ("Purchaser"). Owner and Purchaser are hereinafter sometimes also referred to individually as a "Party" or collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Purchaser is an indirect, wholly-owned subsidiary of Hydro-Québec (as defined below);

WHEREAS, Purchaser anticipates that surplus power, which consists predominantly of low-carbon and renewable hydroelectricity, will be available from the Hydro-Québec System (as defined below) for export into the U.S.;

WHEREAS, on May 22, 2009, FERC (as defined below) issued a declaratory order, as thereafter confirmed by FERC on December 29, 2009, approving the structure of a cost-based, participant-funded transmission project to deliver power from the Province of Québec into New England (as defined below), including a long-term bilateral transmission service agreement with a cost-based rate ceiling, subject to FERC approval of such agreement under Section 205 of the Federal Power Act (as defined below);

WHEREAS, in order to permit the delivery of power from the Hydro-Québec System for sale into the U.S., Hydro-Québec TransÉnergie ("TransÉnergie"), a division of Hydro-Québec, intends to develop, construct, own and maintain a 1,200 MW +/-300 kV high-voltage direct current ("HVDC") transmission line from the converter station at the Des Cantons substation in the Province of Québec to the U.S. Border (as defined below) (as further delineated in the diagram in Attachment A, the "Québec Line");

WHEREAS, Hydro-Québec Production ("HQP"), another division of Hydro-Québec, intends to acquire from TransÉnergie firm transmission service over the Québec Line to permit the delivery of at least 1,200 MW of power into the U.S.;

WHEREAS, Purchaser intends to acquire from HQP, or another Affiliate (as defined below) of Purchaser, electrical capacity and the associated electrical energy at the U.S. Border for resale into the U.S.;

WHEREAS, Owner is a single purpose, indirect, wholly-owned subsidiary of Northeast Utilities (as defined below), created to develop, construct, own and maintain a 1,200 MW +/-300 kV HVDC transmission line extending from the U.S. Border to a direct current ("DC") to alternating current ("AC") converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire (the transmission line and converter station, as more fully described in Attachment A, the "HVDC Line");

WHEREAS, in order to interconnect the HVDC Line with the bulk power systems in New England, Owner intends to develop, construct, own and maintain a radial 345 kV AC transmission line extending from the southern terminus of the HVDC Line to the Deerfield substation in the State of New Hampshire (together with the Franklin substation at its northern terminus and the associated equipment at its southern terminus, as more fully described in Attachment A, the "AC Line," and together with the HVDC Line, the "Northern Pass Transmission Line");

WHEREAS, ISO-NE (as defined below) may require, and Purchaser may desire, certain AC Upgrades (as defined below) to be developed, constructed, owned and maintained by certain transmission owners other than Owner (which may include Affiliates of Northeast Utilities) within their existing service territories in New England in order to interconnect the Northern Pass Transmission Line with the New England Transmission System (as defined below) in a safe and reliable manner, and Purchaser may desire the construction of certain Additional AC Upgrades (as defined below);

WHEREAS, Owner desires to sell to Purchaser Firm Transmission Service (as defined below) and Additional Transmission Service (as defined below), and Purchaser desires to acquire from Owner Firm Transmission Service and Additional Transmission Service, at the rates and on the terms and conditions hereinafter set forth.

NOW, THEREFORE, in consideration of the foregoing and the respective representations, warranties, covenants, agreements and conditions set forth herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the Parties hereby agree as follows:

ARTICLE 1

DEFINITIONS AND RULES OF INTERPRETATION

Section 1.1. Definitions. As used herein, the following terms shall have the following respective meanings:

"AC" has the meaning provided in the recitals to this Agreement.

"AC Line" has the meaning provided in the recitals to this Agreement.

"AC Line Agreement" has the meaning provided in Section 8.6(c).

"AC Line Owner" has the meaning provided in Section 8.6(f).

"AC Upgrade Approvals" means, collectively, any Governmental Approvals or Third Party Consents, in each case, that are required to commence construction of the AC Upgrades.

"AC Upgrade Costs" has the meaning provided in Section 8.5(c).

"AC Upgrade Owners" means, collectively, any Person responsible for constructing one or more AC Upgrades pursuant to a Facilities Agreement.

"AC Upgrades" means, collectively, (a) any additions, upgrades, reinforcements or other modifications to the New England Transmission System that ISO-NE determines pursuant to Section I.3.9 of the ISO-NE Tariff to be required, at a minimum, to interconnect the Northern Pass Transmission Line at the Delivery Point with the New England Transmission System and (b) any such other additions, upgrades, reinforcements or modifications that are (i) identified as part of the transmission project interconnection review by ISO-NE of the Northern Pass Transmission Line in connection with the Section I.3.9 process that Purchaser desires to be constructed and (ii) described in a written notice given by Purchaser to Owner within sixty (60) days after the issuance by ISO-NE of the final Section I.3.9 report. The facilities designated as AC Upgrades may be subject to change in accordance with Section 8.6(g)(iii).

"Additional AC Upgrades" means, collectively, any additions, upgrades, reinforcements or other modifications to the New England Transmission System identified in the Forward Capacity Market qualification process for the sale of 1,200 MW of electrical capacity over the Northern Pass Transmission Line that Purchaser desires to be constructed; provided that Purchaser has notified Owner in writing of such intent within ten (10) Business Days after the date on which a capacity sale for 1,200 MW over the Northern Pass Transmission Line is first cleared in the Forward Capacity Market.

"Additional Financing" means any revolving credit loan or any other financing or indebtedness of any nature for which Owner is liable (other than the Term Financing) (a) that is incurred by Owner to finance or refinance any direct or indirect costs and expenses in connection with the Northern Pass Transmission Line (i) before the Distribution Date (A) under a short-term borrowing arrangement between Owner and one or more of its Affiliates pursuant to the terms of the Northeast Utilities System Money Pool, as filed with FERC, as such terms may be amended from time to time, or (B) at an interest rate not to exceed the lesser of (1) Northeast Utilities' actual cost of borrowing and (2) LIBOR plus two hundred twenty-five (225) basis points, or (ii) after the Commercial Operation Date and (b) the costs for which are recoverable under the Formula Rate in accordance with Article 8. Additional Financing, together with contributions to the equity capital of Owner, shall fund such costs and expenses in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Additional Lender" means any Person that commits to provide Additional Financing.

"Additional Transmission Service" has the meaning provided in Section 7.1.2.

"Affiliate" means, with respect to a specified Person, any other Person that directly or indirectly Controls, is Controlled by or is under common Control with the specified Person; provided, however, that, with respect to Purchaser, a Person shall not be an "Affiliate" of Purchaser unless such Person is Hydro-Québec (including, for the avoidance of doubt, a division of Hydro-Québec) or Controlled by Hydro-Québec.

"AFUDC" means Owner's allowance for funds used during construction of the Northern Pass Transmission Line, as calculated in accordance with FERC's Uniform System of Accounts.

"Agreement" has the meaning provided in the preamble to this Agreement.

"Alternate Manager" has the meaning provided in Section 13.2(a).

"Ancillary Services" means Ancillary Services, as defined in the ISO-NE Tariff.

"Annual Plan and Operating Budget" means an annual statement that sets forth in reasonable detail the projected Revenue Requirement for the applicable period, including interest expenses, Taxes and all other costs or expenses that are (a) projected to be incurred during the applicable period in connection with the Northern Pass Transmission Line and (b) recoverable under the Formula Rate in accordance with Article 8. Without limiting the generality of the foregoing, the Annual Plan and Operating Budget shall include the Maintenance Plan and the Capital Plan.

"Applicable Law" means any duly promulgated federal, national, state, provincial or local law, regulation, rule, ordinance, code, decree, judgment, directive or judicial or administrative order, permit or other duly authorized and valid action of any Governmental Authority, including any binding interpretation of any of the foregoing by any Governmental Authority, which is applicable to a Person, its property or a transaction.

"Approval Deadline" means February 14, 2017, or such other date to which the Parties shall mutually agree in writing.

"Authorized Representatives" has the meaning provided in Section 13.2(a).

"Average Availability" has the meaning provided in Section 16.4(c).

"Base ROE" means the ROE of the New England transmission owners accepted or approved by FERC for Regional Transmission Service, excluding any incentive or other adders approved by FERC.

"Bankruptcy Code" means the United States Bankruptcy Code, 11 U.S.C. § 101 *et seq*.

"Budgeted Amount" has the meaning provided in Section 17.1.1(d)(iii).

"Business Day" means any day except Saturday, Sunday or any other day on which the Federal Reserve member banks are required or authorized to close for business.

"Canadian Approvals" means, collectively, those Governmental Approvals and Third Party Consents, in each case, that are required to commence construction of the Québec Line in a manner consistent with Attachment A, other than the Operational Approvals, all as set forth in Attachment D.

"Canadian Regulatory Event" means a determination by Purchaser, including a reasonable basis for such determination, that (a) one or more Canadian Approvals (i) is reasonably unlikely to be obtained by the Approval Deadline despite the use of commercially reasonable efforts by Purchaser and its Affiliates or (ii) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Purchaser or its Affiliates or (b) the continuation by Purchaser or one or more of its Affiliates of the regulatory or other processes required to obtain one or more Canadian Approvals would be reasonably likely to have a material adverse effect on the business, operations or financial condition of Purchaser or one or more of its Affiliates.

"Capital Plan" means an annual plan for the capital expenditures to maintain the Northern Pass Transmission Line in accordance with Good Utility Practice in order to provide Firm Transmission Service, which plan shall include a description of the scope and nature of the Planned CapEx, the planned outages and overhauls of the Northern Pass Transmission Line associated therewith, and a budget itemized on a monthly basis for the same, which budget shall include all Planned CapEx Costs projected to be incurred with respect to the foregoing activities.

"Capital Structure" means the ratio of (a) the total amount of Owner's debt divided by Owner's total capitalization to (b) the total amount of Owner's equity capital divided by Owner's total capitalization, as such amounts are determined from time to time in accordance with FERC's Uniform System of Accounts.

"Capped Guaranteed Obligations" has the meaning provided in Section 17.1.1(a)(i).

"Carrying Charges" has the meaning provided in Section 8.1.2(e)(iii).

"COD Notice" has the meaning provided in Section 4.1(c).

"Commercial Operation" means the availability of the Northern Pass Transmission Line for the provision of Firm Transmission Service in accordance with this Agreement.

"Commercial Operation Date" has the meaning provided in Section 4.1(c).

"Commissioning" means (a) with respect to Northern Pass Transmission Line, the start-up and testing activities required to demonstrate that the Northern Pass Transmission Line is ready for Commercial Operation and (b) with respect to the Québec Line, the start-up and testing activities required to demonstrate that the Québec Line is ready for commercial operation, consistent with Section 4.2(f).

"Confidential Information" means (a) any documents, analyses, compilations, studies, or other materials prepared by or information received from a Party or its representatives that contain or reflect written or oral data or information that is privileged, confidential, or proprietary and that is marked or otherwise clearly identified as "confidential" or "proprietary" or with words of like meaning, or (b) any subsequently prepared documents, analyses, compilations, studies, or other materials or information that are derived from any of the documents, analyses, compilations, studies, or other materials or information described in the foregoing clause (a).

Without limiting the generality of the foregoing, all information provided to Purchaser or Owner or their respective Managers under Section 2.3(a)(iii), Section 5.1.2(e)(iii), Section 5.2.1(a), Section 5.2.2(a), Section 5.2.3(a), Section 5.2.4(b), Section 6.3(a), Section 6.3(b)(iv), Section 6.4(a), Section 6.6(a), Section 9.3.2(a), Section 14.2(b), Section 17.1.1(f) and Section 18.1(a) shall be deemed to be Confidential Information, whether or not such information is marked as "confidential" or "proprietary."

"Consent" means, with respect to a Person, any approval, consent, permit, license, decree, certificate or other authorization of or from such Person.

"Construction Authorizations" means, collectively, those Governmental Approvals and Third Party Consents, in each case, that are required to commence construction of the Northern Pass Transmission Line, other than the Operational Approvals.

"Construction Budget and Schedule" has the meaning provided in Section 5.2.2(a).

"Construction Contract" means any contract entered into by Owner that provides for the engineering, procurement or construction of the Northern Pass Transmission Line.

"Construction Costs" means, collectively, all direct and indirect costs that are (a) incurred by Owner in connection with the Northern Pass Transmission Line before the Commercial Operation Date and recorded in FERC Account No. 107 – Construction Work in Progress (including costs incurred before the Effective Date that are included in such account, but excluding costs associated with the drafting and negotiation of this Agreement) and (b) recoverable under the Formula Rate in accordance with Article 8.

"Construction Loan Agreement" means an agreement by and between Owner, as borrower thereunder, and Hydro-Québec Lender, pursuant to which Hydro-Québec Lender shall finance a portion of the Project Costs with loans to Owner on a senior secured basis. Loans under the Construction Loan Agreement, together with contributions to the equity capital of Owner, shall fund all Project Costs in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Construction Phase" means the period commencing on February 28, 2015, or such other date to which the Parties shall mutually agree in writing, and ending on the day immediately preceding the Commercial Operation Date or upon the earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Construction Progress Report" has the meaning provided in Section 5.2.4(b).

"Contract Capacity" means (a) 1,200 MW or (b) such lesser amount as may be established by the Commissioning of the Northern Pass Transmission Line, in each case, as measured at the Delivery Point.

"Contract Year" means each calendar year during the Term, except that (a) the first Contract Year shall commence on the Commercial Operation Date and terminate on the following December 31st and (b) the final Contract Year shall terminate at the end of the Term.

"Control" (including its correlative meanings "Controlled by" and "under common Control with") means, with respect to a Person, the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of the specified Person, whether through ownership of voting securities or partnership or other ownership interests, by contract or Applicable Law or otherwise.

"Contractor" means Hydro-Québec Contractor or any other Person that agrees to provide engineering, procurement or construction services with respect to the Northern Pass Transmission Line pursuant to a Construction Contract.

"Cost-of-Service Estimate" means a non-binding statement that sets forth in reasonable detail a good faith estimate of the Revenue Requirement for the first full year during the Operation Phase calculated in accordance with the Formula Rate and applicable FERC rules and regulations.

"Critical Energy Infrastructure Information" means any information defined as Critical Energy Infrastructure Information by FERC pursuant to 18 C.F.R. § 388.113, and shall include all Critical Infrastructure Protection (CIP) standards (CIP-002 through CIP-009) established by NERC.

"DC" has the meaning provided in the recitals to this Agreement.

"Decommissioning" means the performance of the work required to (a) retire the Northern Pass Transmission Line and dismantle the materials, equipment and structures comprising the Northern Pass Transmission Line and (b) restore and rehabilitate any land affected by the construction or dismantlement of the Northern Pass Transmission Line, in each case, as required by Applicable Law.

"Decommissioning Costs" means, collectively, any costs and expenses that are incurred by Owner to Decommission the Northern Pass Transmission Line in accordance with this Agreement.

"Decommissioning Estimate" has the meaning provided in Section 9.3.3(c).

"Decommissioning Fund" has the meaning provided in Section 9.3.3(b).

"Decommissioning Liquidated Damages" has the meaning provided in the Purchaser Guaranty.

"Decommissioning Payment Date" has the meaning provided in Section 9.3.3(c).

"Decommissioning Payment Formula " means the following formula:

$$\frac{c}{[(1 + c)^{60} - 1]}$$

Where:

c is the reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (expressed as a percentage).

"Decommissioning Payment Period" has the meaning provided in Section 9.3.3(a).

"Decommissioning Plan" has the meaning provided in Section 9.3.2(a).

"Delivery Point" means the southern terminus of the Northern Pass Transmission Line at the Deerfield substation in the State of New Hampshire, as illustrated in Attachment A. This definition may be subject to change in accordance with Section 8.6(g)(i).

"Design Capability" means the maximum amount of electric power that the materials, equipment and structures comprising the HVDC Transmission Project will be designed to transfer bidirectionally in a safe and reliable manner, which amount shall be sufficient to permit the north-to-south delivery of not less than 1,200 MW of electrical energy at the Delivery Point.

"Design Materials" means, collectively, any engineering or technical study, project design, report, analysis, compilation, regulatory filing or other similar data or document prepared by Owner, any Affiliate of Owner or any third-party contractor in connection with the Northern Pass Transmission Line, other than any privileged communications or proprietary intellectual property rights.

"Determined Cap" means the amount determined in accordance with Section 17.1.1 from time to time.

"Development Phase" means the period commencing on January 1, 2009 and ending on the day immediately preceding the commencement of the Construction Phase or upon the earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Dispute" means any dispute, controversy or claim of any kind whatsoever arising out of or relating to this Agreement, including the interpretation of the terms hereof or any Applicable Law that affects this Agreement, or the transactions contemplated hereunder, or the breach, termination or validity thereof.

"Dispute Notice" has the meaning provided in Section 18.1(a).

"Distribution Date" means the date on which funds are initially distributed by Hydro-Québec Lender under the Construction Loan Agreement.

"Effective Date" has the meaning provided in Section 3.1.

"EPC Costs" means, collectively, any costs and expenses for which Owner is liable pursuant to any Construction Contract, other than costs and expenses for which Purchaser shall have agreed in writing to reimburse to Owner in the event this Agreement is terminated under Section 3.3.3. For the avoidance of doubt, "EPC Costs" shall include any penalties, damages, fees or other amounts that Owner is required to pay as a result of the termination of any Construction Contract, other than penalties, damages, fees or other amounts for which Purchaser shall have agreed in writing to reimburse to Owner in the event this Agreement is terminated under Section 3.3.3.

"Estimated Wind-Down Costs" means the aggregate amounts described in clause (c) of the definition of "Owner's Costs" that reasonably would be expected to be incurred by Owner upon an early termination of this Agreement, subject to the exclusions to such definition.

"Excluded Claims" means any (a) claims of any Affiliate of Purchaser arising under the TransÉnergie OATT, (b) claims of any Persons residing in, or arising from events in, the Province of Québec (other than claims of any Persons residing in the Province of Québec that arise out of physical injuries suffered in the U.S.) and (c) claims arising out of a contract between Purchaser and any third party.

"Excused Outages" has the meaning provided in Section 7.3(a).

"Execution Date" has the meaning provided in the preamble to this Agreement.

"Existing Guaranty" has the meaning provided in Section 17.1.1(e).

"Expert Arbitration" has the meaning provided in Section 18.3.1(b).

"Expert Arbitrator" means a natural person who (a) is neutral and impartial, (b) has knowledge and expertise in the electric power industry, (c) has not had any commercial relationship with any Party or an Affiliate of a Party (whether as an employee, contractor or otherwise) for at least five (5) years before being appointed an arbitrator hereunder and (d) is fluent in the English language. A natural person shall not qualify as an "Expert Arbitrator" if his or her spouse, children, parents or siblings (x) has a financial interest in the outcome of any Dispute or (y) does not satisfy the criteria described in the foregoing clause (c).

"Expert Arbitrator Candidates" has the meaning provided in Section 18.3.1(a).

"Export Authorizations" means one or more Export Authorizations issued by the U.S. Department of Energy as required for the exportation of electric power into Canada.

"Extended Outage" has the meaning provided in Section 16.4(a).

"Extraordinary CapEx" means, collectively, any capital improvements and projected upgrades, replacements and repairs to the Northern Pass Transmission Line that are (a) required to maintain the Northern Pass Transmission Line in accordance with Good Utility Practice in order to provide Firm Transmission Service and (b) not set forth in the Capital Plan for the applicable period.

"Extraordinary CapEx Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner in connection with Extraordinary CapEx and (b) recoverable under the Formula Rate in accordance with Article 8.

"Extraordinary CapEx Plan" has the meaning provided in Section 6.6(a).

"Facilities Agreement" has the meaning provided in Section 8.5(a).

"Federal Power Act" means the United States Federal Power Act of 1935, as amended, 16 U.S.C. § 791a *et seq*.

"FERC" means the Federal Energy Regulatory Commission, or any successor regulatory agency that administers the Federal Power Act.

"FERC Amendment" has the meaning provided in Section 2.2(b)(i).

"FERC Authorization" means, collectively, any FERC order authorizing Owner to provide Firm Transmission Service and Additional Transmission Service, including the FERC Order and any authorization from FERC with respect to the Transmission Operating Agreement, Interconnection Agreements or Facilities Agreements.

"FERC Order" has the meaning provided in Section 2.2(a)(i).

"FERC's Uniform System of Accounts" means 18 C.F.R. Part 101 (2009).

"Financial Transmission Rights" means Financial Transmission Rights, as defined in the ISO-NE Tariff.

"Financing Parties" means, collectively, Hydro-Québec Lender, the Term Loan Lender and any Additional Lender.

"Firm Transmission Service" has the meaning provided in Section 7.1.1.

"Force Majeure" has the meaning provided in Section 16.1(a).

"Formula Rate" means the formula set forth in Attachment B, which formula shall be used to calculate the Transmission Service Payments in accordance with the provisions hereof.

"Good Utility Practice" means those design, construction, operation, maintenance, repair, removal and disposal practices, methods, and acts that are engaged in by a significant portion of the electric transmission industry in the United States during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method, or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods, or acts generally accepted in such electric transmission industry for the design, construction, operation, maintenance, repair, removal and disposal of electric transmission facilities in the United States. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods, or acts undertaken but rather shall be determined based upon the consistency of (a) the practices, methods, or acts when undertaken with (b) the standard set forth in the first two (2) sentences of this definition at such time.

"Governmental Approval" means (a) any authorization, consent, approval, license, lease, ruling, permit, tariff, rate, certification, waiver, exemption, filing, variance, claim, order, judgment, or decree of, by or with, (b) any required notice to, (c) any declaration of or with, or (d) any registration by or with, any Governmental Authority, including any FERC Authorization.

"Governmental Authority" means any government or agency or other political subdivision thereof, including any province, state or municipality, or any other governmental, quasi-governmental, judicial, executive, legislative, administrative, regulatory, public or statutory instrumentality, authority, body, agency, commission, department, board, bureau or entity exercising judicial, executive, legislative, administrative or regulatory functions, any court or arbitrator with authority to bind a party at law, and shall include, to the extent exercising powers delegated by any Governmental Authority acting under Applicable Law, NERC and ISO-NE.

"Hourly Availability" means, with respect to any hour, the availability of the Northern Pass Transmission Line, which shall equal the (a) the Total Transfer Capability for such hour, divided by (b) the Contract Capacity, expressed as a percentage; provided, however, that, for any hour, the availability of the Northern Pass Transmission Line shall not exceed one hundred percent (100%).

"HQP" has the meaning provided in the recitals to this Agreement.

"HVDC" has the meaning provided in the recitals to this Agreement.

"HVDC Line" has the meaning provided in the recitals to this Agreement.

"HVDC Transmission Project" means, collectively, (a) the Québec Line and (b) the Northern Pass Transmission Line.

"Hydro-Québec" means Hydro-Québec, a body politic and corporate, duly incorporated and regulated by the Hydro-Québec Act (R.S.Q., Chapter H-5). As of the Execution Date, Hydro-Québec has four divisions: HQP, TransÉnergie, Hydro-Québec Distribution and Hydro-Québec Équipment.

"Hydro-Québec Contractor" means one or more Affiliates of Purchaser that agree to provide engineering, procurement or construction services with respect to the Northern Pass Transmission Line pursuant to a Construction Contract.

"Hydro-Québec Lender" means Hydro-Québec acting in its capacity as lender under the Construction Loan Agreement.

"Hydro-Québec System" means, collectively, (a) certain generating stations, located in the Province of Québec and owned and operated by Hydro-Québec or its subsidiaries, that produce electric power, which consists predominantly of low-carbon and renewable hydroelectricity, (b) hydroelectric power produced by certain independent power producers, which power Hydro-Québec or its subsidiaries has contractual rights to purchase and resell, and (c) other power purchased by Hydro-Québec or its subsidiaries from third parties for resale.

"ICC" has the meaning provided in Section 18.3.1(c).

"Immunities Act" mean the United States Foreign Sovereign Immunities Act of 1976, 28 U.S.C. § 1602 *et seq*.

"Impasse" has the meaning provided in Section 13.9.

"Income Tax" means any tax imposed on net income by any Governmental Authority.

"Indemnification Notice" has the meaning provided in Section 21.3.

"Indemnified Party" has the meaning provided in Section 21.3.

"Indemnifying Party" has the meaning provided in Section 21.3.

"Initial Allowance" means the amount, expressed in megawatt-hours, equal to (a) the Contract Capacity, multiplied by (b) 720.

"Insolvency Event" means, with respect to a Person, such Person (a) becomes "insolvent," as defined in the Bankruptcy Code, or otherwise becomes bankrupt or insolvent under any Insolvency Laws, (b) has a liquidator, administrator, receiver, custodian, trustee, conservator or similar official appointed with respect to such Person or any material portion of such Person's assets or such Person consents to such appointment, or a foreclosure action is instituted with respect to any material portion of such Person's assets, (c) files a voluntary petition or otherwise authorizes or commences a proceeding or cause of action under the Bankruptcy Code or Insolvency Laws, (d) has an involuntary petition filed against it or acquiesces in the commencement of a proceeding or cause of action as the subject debtor under the Bankruptcy Code or Insolvency Laws, which petition is not dismissed within thirty (30) days after the filing thereof or results in the issuance of an order for relief against such Person, (e) makes or consents to an assignment of its assets in whole or in part, or any general arrangement for the benefit of creditors, or a common law composition of creditors, or (f) generally is unable to pay its debts as they fall due, or admits in writing to such inability.

"Insolvency Laws" means any bankruptcy, insolvency, reorganization or similar laws of the U.S., Canada, or other Governmental Authority, as applicable, other than the Bankruptcy Code.

"Interconnection Agreements" means, collectively, (a) an agreement by and among Owner, TransÉnergie and ISO-NE that sets forth such parties' respective rights and obligations following the interconnection at the U.S. Border of the Northern Pass Transmission Line with the Québec Line and (b) an agreement by and among Owner, PSNH and ISO-NE that sets forth such parties' respective rights and obligations following the interconnection at the Delivery Point of the Northern Pass Transmission Line with certain transmission facilities owned by PSNH. The Interconnection Agreements shall address cost responsibilities and shall include provisions, both technical and otherwise, for safe and reliable interconnected operations of the HVDC Transmission Project following Commercial Operation (including use of the HVDC Transmission Project for the delivery of electric power in emergency circumstances).

"Invoice" means, with respect to a calendar month, an invoice that sets forth the amounts owed to Owner by Purchaser with respect to such month in reasonable detail to evidence the basis for individual billings and charges.

"ISO-NE" means ISO New England Inc., or its successor organization.

"ISO-NE Approval" means approval by ISO-NE to operate the Northern Pass Transmission Line at 1,200 MW.

"ISO-NE Definitions Manual" means the ISO New England Manual for Definitions and Abbreviations, Manual M-35, as in effect from time to time.

"ISO-NE Rules" means the ISO-NE Tariff and all ISO-NE manuals, rules, procedures, agreements or other documents relating to the reliable operation of the electric system in New England and the purchase and sale of electrical energy, electrical capacity and ancillary services, as such govern market participants with respect thereto in the operating jurisdiction of ISO-NE, as in effect from time to time, including the ISO-NE Definitions Manual; provided that such documents are publicly accessible.

"ISO-NE Tariff" means the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, as in effect from time to time, on file with FERC, or its successor tariff.

"kV" means kilovolt.

"Letter Agreement" means that certain Letter Agreement for Recovery of Northern Pass Transmission Line Project Development Costs, of even date herewith, a copy of which is attached hereto as Attachment G and made a part hereof or any modification to such Letter Agreement (or superseding letter agreement) executed by the parties thereto; provided that Owner shall have filed a copy of any such modification to such Letter Agreement (or superseding letter agreement) with FERC with a request for approval or acceptance not less than sixty (60) days before Owner renders an invoice to Purchaser for costs and expenses incurred by Owner that are recoverable thereunder.

"Levelized Monthly Decommissioning Payment" has the meaning provided in Section 9.3.1(b).

"LIBOR" means the British Bankers' Association Interest Settlement Rate per annum for deposits in U.S. Dollars (for a term comparable to the interest period selected by Owner in accordance with the Loan Documents for the applicable Additional Financing described in clause (a)(i)(B) of the definition thereof), appearing on the display designated as Page 3750 on the Dow Jones Markets Service (or such other page on that service or such other service designated by the British Bankers' Association for the display of such Association's Interest Settlement Rates for U.S. Dollar deposits) as of 11:00 a.m. (London, England time) or if such Page 3750 is unavailable for any reason, the rate that appears on the Reuters Screen ISDA Page as of such date and such time.

"Loan Agreements" means, collectively, (a) the Construction Loan Agreement, (b) the Term Loan Agreement and (c) the loan and credit agreements entered into by Owner with respect to any Additional Financing.

"Loan Documents" means the Loan Agreements and the other instruments and documents evidencing or securing the obligations of Owner to the Financing Parties under the Loan Agreements.

"Loss Occurrence" means any material loss of, destruction of or damage to, or any condemnation of, the Northern Pass Transmission Line due to an event of Force Majeure.

"Maintenance Plan" means an annual plan for the management, operation and ordinary maintenance of the Northern Pass Transmission Line, which plan shall include a description of the scope and nature of the planned operating and maintenance programs and planned and preventive maintenance procedures for the Northern Pass Transmission Line, the scheduled maintenance and other planned outages of the Northern Pass Transmission Line, and a budget itemized on a monthly basis for the same, which budget shall include all projected O&M Costs projected to be incurred with respect to the foregoing activities.

"Management Committee" has the meaning provided in Section 13.1.

"Manager" has the meaning provided in Section 13.2(a).

"Market Products" means, collectively, all products (however entitled and whether existing now or in the future) that (a) are recognized under ISO-NE Rules, (b) derive from the acquisition of transmission service over the Northern Pass Transmission Line under this Agreement, and (c) can be sold for consideration or otherwise have economic value, including electrical energy, electrical capacity and ancillary services, including reserve products (including spinning and non-spinning reserves).

"Material Adverse Effect" means, with respect to a Party, a material adverse effect on the ability of such Party to perform any of its obligations under this Agreement.

"Membership Pledges" has the meaning provided in Section 17.2.1.

"Minimum Average Availability" means seventy-five percent (75%) of the Contract Capacity.

"Multiyear Outlook" has the meaning provided in Section 6.3(a).

"MW" means megawatt.

"MWh" means megawatt-hour.

"Necessary Administrative Functions" has the meaning provided in Section 10.3(c)(i).

"NEPOOL" means the New England Power Pool and the entities that collectively participate in the New England Power Pool.

"NERC" means the North American Electric Reliability Corporation, or its successor organization.

"Net Decommissioning Costs" means Decommissioning Costs, less any Salvage Proceeds; provided, however, that if the Salvage Proceeds exceed the Decommissioning Costs, then the Net Decommissioning Costs shall equal Zero Dollars ($0).

"Net Present Value of Owner's Equity Return" means the amount obtained by discounting the ROE portion of all remaining Transmission Service Payments that would have been recoverable under this Agreement absent the termination thereof using the ROE (as established pursuant to Section 8.4(b)) in effect as of the applicable termination date, which amount shall be calculated in accordance with customary financial practice and at a discount factor equal to the Base ROE in effect as of the applicable termination date.

"New England" means, collectively, the State of Maine, State of New Hampshire, State of Vermont, Commonwealth of Massachusetts, State of Rhode Island and State of Connecticut.

"New England Transmission System" means New England Transmission System, as defined in the ISO-NE Tariff.

"Non-Excused Outage" has the meaning provided in Section 7.4.1.

"Northeast Utilities" means Northeast Utilities, a public utility holding company organized and existing as a voluntary trust under the laws of the Commonwealth of Massachusetts.

"Northern Pass Transmission Line" has the meaning provided in the recitals to this Agreement. This definition may be subject to change in accordance with Section 8.6(g)(ii).

"NPCC" means the Northeast Power Coordinating Council, Inc., or its successor organization.

"NPCC Approval" means approval by NPCC to operate the Northern Pass Transmission Line at 1,200 MW.

"NSTAR" means NSTAR, a public utility holding company organized and existing as a voluntary association under the laws of the Commonwealth of Massachusetts.

"O&M Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner during the Operation Phase in connection with the operation and maintenance of the Northern Pass Transmission Line (excluding Decommissioning Costs) and (b) recoverable under the Formula Rate in accordance with Article 8.

"OASIS Administrator" has the meaning provided in Section 10.3(c).

"OASIS Provider" has the meaning provided in Section 10.3(a).

"OATT Payments" has the meaning provided in Section 4.3.1(b)(i).

"Operation Phase" means the period commencing on the Commercial Operation Date and ending upon the expiration of the Term or earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Operational Approvals" means, collectively, (a) the ISO-NE Approval and (b) the NPCC Approval.

"Other Regulatory Event" means a determination by Purchaser, including a reasonable basis for such determination, that one or more Operational Approvals (a) is reasonably unlikely to be obtained by the Approval Deadline or (b) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Purchaser or its Affiliates.

"Other Transmission Rights" means collectively, any Financial Transmission Rights (or any similar concept), auction revenue rights or other financial or physical transmission rights, in each case, whether existing now or in the future, associated with the Northern Pass Transmission Line or AC Upgrades.

"Outstanding Claim" has the meaning provided in Section 17.1.1(e).

"Owner" has the meaning provided in the preamble to this Agreement.

"Owner Approvals" means, collectively, (a) the Construction Authorizations and (b) those other Governmental Approvals and Third Party Consents, in each case, that are required to develop, construct, own and operate the Northern Pass Transmission Line, other than the Operational Approvals, all as set forth in Attachment C.

"Owner Default" has the meaning provided in Section 15.2.

"Owner Delay" has the meaning provided in Section 4.3.1(a).

"Owner Guaranty" has the meaning provided in Section 17.1.2(a), as in effect from time to time.

"Owner Indemnified Party" has the meaning provided in Section 21.1.

"Owner Retained Property" means, collectively, (a) all fee simple and other interests in real property (including rights-of-way, other easements and leasehold interests in real property), (b) proprietary intellectual property and (c) other intangible property (including development rights), in each case, associated with the Northern Pass Transmission Line.

"Owner's Costs" means an amount equal to the sum of the following, without duplication, (a) all costs and expenses incurred by Owner before the applicable termination date (whether payable before, on or after such date) that would have been recoverable under this

Agreement (including under Section 8.1.4, without altering the otherwise applicable burden of proof set forth in Section 8.1.4(b) for prudency challenges) absent the termination thereof, other than Decommissioning Costs and costs and expenses incurred with respect to any Owner Retained Property, plus (b) the debt component of AFUDC, as accrued on the applicable portion of the costs described in the foregoing clause (a) in accordance with Section 8.1.2 and included in the calculation of Rate Base, plus (c) all wind-down costs, penalties, damages, fees and other amounts that Owner is required to pay to third parties as a result of the termination of this Agreement, any Facilities Agreement or any other contract or lease (excluding contracts or leases with respect to Owner Retained Property) entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, including, for the avoidance of doubt, any penalties, damages, fees or other amounts for which Owner is liable under the Loan Agreements as a result of the prepayment of the loans made to Owner thereunder, but excluding any Decommissioning Costs. In no event shall any penalties, damages, fees or other amounts that Owner is required to pay to its Affiliates qualify as "Owner's Costs" unless Owner is liable for such penalties, damages, fees or amounts pursuant to a transaction or other arrangement that is on terms and conditions at least as favorable to Owner, when taken as a whole, as would have been obtained (at the time entered into) in a comparable arm's-length transaction or arrangement with a Person other than an Affiliate of Owner; provided, however, that, if such transaction or arrangement has been accepted or approved by FERC or any other Governmental Authority that specifically reviews the Affiliate relationship in such transaction or arrangement, then such transaction or arrangement shall be deemed to be a comparable arm's-length transaction or arrangement. For the avoidance of doubt, the amounts described in the foregoing two (2) sentences shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Owner's Costs Plus EAFUDC" means an amount equal to the sum of the following, without duplication, (a) Owner's Costs, plus (b) the equity component of AFUDC, as accrued on the applicable portion of Owner's Costs in accordance with Section 8.1.2 and included in the calculation of Rate Base. For the avoidance of doubt, the amounts described in the foregoing sentence shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Owner's Initial Deadline" has the meaning provided in Section 4.3.1(a).

"Owner's Final Deadline" has the meaning provided in Section 4.3.1(b).

"Panel" has the meaning provided in Section 18.3.1(a).

"Parties" and "Party" have the meanings provided in the preamble to this Agreement.

"Person" means any legal person, including any natural person, domestic or foreign corporation, limited liability company, general or limited partnership, joint venture, association, joint stock company, business trust, estate, trust, enterprise, unincorporated organization, any Governmental Authority, or any other legal or commercial entity.

"Planned CapEx" means, collectively, the planned capital improvements and projected upgrades, replacements and repairs to the Northern Pass Transmission Line.

"Planned CapEx Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner in connection with Planned CapEx and (b) recoverable under the Formula Rate in accordance with Article 8.

"Position Statement" means a statement of a Party's position on a particular matter or issue and a summary of facts and arguments supporting that position.

"Pre-COD Expenses" mean all costs and expenses that are (a) incurred by Owner in connection with the Northern Pass Transmission Line and the AC Upgrades before the Commercial Operation Date and not included in FERC Account No. 107 – Construction Work in Progress (including the AC Upgrade Costs associated with AC Upgrades that are placed-in-service before the Commercial Operation Date and are included in the regulatory asset described in Section 8.1.2(e), but excluding costs and expenses associated with the drafting and negotiation of this Agreement) and (b) recoverable under the Formula Rate in accordance with Article 8.

"Preliminary Monthly Decommissioning Payment" has the meaning provided in Section 9.3.3(a)(i).

"Preliminary Budget and Schedule" has the meaning provided in Section 5.2.1(a).

"Prior Claims" has the meaning provided in Section 17.1.1(e).

"Project Assets" means, collectively, all materials, equipment and structures owned by Owner, excluding the Owner Retained Property.

"Project Budget" means, collectively, (a) a budget consisting of line item estimates of all Project Costs, including reasonable contingency amounts applied to individual line item estimates or to the Project Costs as a whole, and (b) a budget of estimated AC Upgrade Costs projected to be incurred before the Commercial Operation Date in such detail as can reasonably be obtained by Owner from the AC Upgrade Owners, recognizing that one or more Project Budgets will be completed and delivered before the date on which the AC Upgrades are formally identified under this Agreement.

"Project Costs" means, collectively, (a) the Construction Costs, and (b) the Pre-COD Expenses.

"Project Debt" means Owner's debt to finance the costs and expenses incurred by Owner in connection with the Northern Pass Transmission Line under (a) the Construction Loan Agreement, (b) the Term Loan Agreement and (c) the loan and credit agreements entered into by Owner with respect to any Additional Financing, the aggregate amount of which debt shall be consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Project Debt Obligations" means all obligations of every nature of Owner from time to time owed to any Financing Party under the Loan Documents, whether for principal, interest or payments for early termination of interest rate hedging agreements, fees, expenses, indemnification or otherwise and all guarantees of any of the foregoing. Notwithstanding the foregoing, unless otherwise agreed in writing by Purchaser, if the outstanding principal amount of the Project Debt Obligations (together with the face amount of letters of credit and the amount of unfunded commitments under the Loan Documents) is in excess of the principal amount of Project Debt that Owner is permitted to incur consistent with its obligations under Section 5.6 and Section 8.3(a), then Project Debt Obligations shall include only (a) that portion of the principal amount of Project Debt that Owner is so permitted to incur consistent with its obligations under Section 5.6 and Section 8.3(a), plus (b) interest, fees and reimbursement obligations in respect of such portion of such principal amount, plus (c) any other principal consisting of capitalization or funding of such interest, fees or reimbursement obligations.

"Project Schedule" means a schedule setting forth the proposed engineering, procurement, construction and testing milestone schedule for (a) the Northern Pass Transmission Line based upon the Construction Contracts and (b) the AC Upgrades based upon such information as can reasonably be obtained by Owner from the AC Upgrade Owners, recognizing that one or more Project Schedules will be completed and delivered before the date on which the AC Upgrades are formally identified under this Agreement.

"PSNH" means Public Service Company of New Hampshire, a corporation organized and existing under the laws of the State of New Hampshire.

"PTF" has the meaning provided in Section 8.6(b).

"Purchaser" has the meaning provided in the preamble to this Agreement.

"Purchaser Default" has the meaning provided in Section 15.1.

"Purchaser Guaranty" has the meaning provided in Section 17.1.1(a), and includes any Purchaser Guaranty reissued in accordance with Section 17.1.1(g) or Section 17.1.1(i).

"Purchaser Indemnified Party" has the meaning provided in Section 21.2.

"Purchaser Mortgage" has the meaning provided in Section 17.2.1.

"Purchaser's Deadline" has the meaning provided in Section 4.3.2(b).

"Purchaser's Decommissioning Balance" has the meaning provided in Section 9.3.4.

"Purchaser's Lien" has the meaning provided in Section 17.2.1.

"Purchaser's Security Documents" has the meaning provided in Section 17.2.1.

"Québec Damages" has the meaning provided in Section 7.4.2.

"Québec Line" has the meaning provided in the recitals to this Agreement.

"Rate Base" has the meaning provided in Section III.A. of Attachment B.

"Rate Base Calculation" has the meaning provided in Section 16.3(c)(i).

"Real Power Losses" means energy consumed by the electrical impedance characteristics of the Northern Pass Transmission Line.

"Reconstruction Costs" means, with respect to a Loss Occurrence, collectively, all costs and expenses that are (a) incurred by Owner to reconstruct or otherwise repair the Northern Pass Transmission Line following such Loss Occurrence, net of insurance proceeds and other amounts received by Owner in connection therewith (excluding any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to such Loss Occurrence), and (b) recoverable under the Formula Rate in accordance with Article 8.

"Reconstruction Plan" has the meaning provided in Section 16.3(c)(i).

"Recovery" has the meaning provided in Section 21.6.

"Redetermination Certificate" has the meaning provided in Section 17.1.1(f).

"Redetermination Date" means (a) during the Construction Phase, (i) the first day of the first calendar month following the delivery of the first Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2, and (ii) each anniversary of such date thereafter until the date immediately preceding the Commercial Operation Date, and (b) during the Operation Phase, (i) the Commercial Operation Date, (ii) the first day of the third Contract Year after the Commercial Operation Date, and (iii) the first day of each third Contract Year thereafter.

"Regional Rates" means the rates for Regional Transmission Service.

"Regional Transmission Service" means Regional Transmission Service, as defined in and provided under the ISO-NE Tariff.

"Replacement Transmission Cost" means, with respect to each hour of a period of time during a Non-Excused Outage, the amount equal to (a)(i) the positive difference, if any, between (A) the price per MWh that Purchaser paid for replacement transmission service acquired by Purchaser during such hour to New England from the international border between the Province of Québec and the United States and (B) the price per MWh that Purchaser would have paid under this Agreement based upon the full Transmission Service Payment due for such period, multiplied by (ii) the amount of transmission capacity (expressed in MW) that Purchaser acquired for such hour (capped at the amount of unavailable transmission capacity during such hour resulting from a Non-Excused Outage), plus (b) any reasonable transaction costs incurred by Purchaser in connection with the foregoing purchase.

"Revenue Requirement" means the annual transmission revenue requirement of Owner, as determined in accordance with the Formula Rate.

"ROE" has the meaning provided in Section 8.4(a).

"Rules" has the meaning provided in Section 18.3.2(a).

"Salvage Proceeds" has the meaning provided in Section 9.3.5(b)(ii).

"Satisfying Amount" has the meaning provided in Section 17.1.1(e).

"Scheduling Rules" has the meaning provided in Section 7.1.4.

"Security Agreement" has the meaning provided in Section 17.2.1.

"Stated Cap" means the amount set forth in Section 1(a)(i) of the Purchaser Guaranty, as in effect from time to time.

"Subordination Agreement" has the meaning provided in Section 17.2.2.

"Subsequent Use" has the meaning provided in Section 9.2.

"Target Date" means the date that coincides with the guaranteed substantial completion date as established under the principal Construction Contract, which date is preliminarily expected to be in 2015.

"Taxes" means, collectively, all categories of taxes identified as recoverable under the Formula Rate.

"Technical Dispute" has the meaning provided in Section 18.3.1(b).

"Technical Dispute Notice" has the meaning provided in Section 18.3.1(b).

"Term" has the meaning provided in Section 3.2.

"Term Financing" means a financing evidenced by a Term Loan Agreement.

"Term Financing Parameters" means parameters established by the Management Committee for the terms and conditions of a Term Financing in accordance with Section 5.1.2(e).

"Term Financing Procedures" has the meaning provided in Section 5.1.2(e)(i).

"Term Loan Agreement" means the loan and credit agreements entered into by Owner with respect to any refinancing of the Construction Loan Agreement or any subsequent refinancing of the loans made under such loan and credit agreements. Loans under the Term Loan Agreement shall fund such refinancing in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Term Loan Lender" means, collectively, any Person that commits to provide loans to Owner under the Term Loan Agreement.

"Termination Payment" means an amount equal to the sum of the following, without duplication, (a) Owner's Costs Plus EAFUDC, plus (b) the Net Present Value of Owner's Equity Return as of the applicable termination date. For the avoidance of doubt, the amounts described in the foregoing sentence shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Third Party Claim" has the meaning provided in Section 21.3.

"Third Party Consent" means any Consent of a Person other than a Governmental Authority.

"Third Party Rehearing Request" means any request by a third party for rehearing of the FERC Order.

"Total Transfer Capability" means the Total Transfer Capability of the Northern Pass Transmission Line, as defined in, and established in accordance with, the ISO-NE Tariff and determined by ISO-NE for each hour.

"TransÉnergie" has the meaning provided in the recitals to this Agreement.

"TransÉnergie OATT" means the Hydro-Québec Open Access Transmission Tariff, as amended or accepted by the Régie de l'énergie from time to time.

"Transfer" has the meaning provided in Section 23.1(a).

"Transmission Operating Agreement" means an agreement entered into by and between Owner and ISO-NE for transmission operating services over the Northern Pass Transmission Line under which operating control (as defined in such agreement) of the Northern Pass Transmission Line is transferred from Owner to ISO-NE.

"Transmission Operator" means ISO-NE acting in its capacity pursuant to the Transmission Operating Agreement.

"Transmission Service Payment" has the meaning provided in Section 8.1.2(b).

"Unfavorable FERC Decision" has the meaning provided in Section 2.2(a)(ii).

"United States" or "U.S." means the United States of America.

"U.S. Border" means the location on or near the international border between the State of New Hampshire and the Province of Québec where the HVDC Line and the Québec Line interconnect.

"U.S. Regulatory Event" means a determination by Owner, including a reasonable basis for such determination, that (a) one or more Construction Authorizations (i) is reasonably unlikely to be obtained by the Approval Deadline despite the use of commercially reasonable efforts by Owner and its Affiliates or (ii) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Owner or one or more of its Affiliates or (b) the continuation by Owner or one or more of its Affiliates of the regulatory or other processes required to obtain one or more Construction Authorizations would be reasonably likely to have a material adverse effect on the business, operations or financial condition of Owner or one or more of its Affiliates.

Section 1.2. Interpretation. In this Agreement, unless the context otherwise requires, the following rules shall apply to the usage of terms:

Section 1.2.1. Singular; Plural; Gender; Corollary Meaning. The singular shall include the plural and vice versa, and any pronoun shall include the corresponding masculine, feminine and neuter forms. If a term is defined as one part of speech (such as a noun), then it shall have a corresponding meaning when used as another part of speech (such as a verb).

Section 1.2.2. Coordinating Conjunctions. The word "or" shall have the inclusive meaning represented by the phrase "and/or."

Section 1.2.3. Self Reference. The words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement.

Section 1.2.4. Inclusive References. The words "include," "includes" and "including" when used in this Agreement shall be deemed to be followed by "without limitation" or "but not limited to," whether or not they are in fact followed by such words or words of like import.

Section 1.2.5. Incorporation by Reference. Any reference in this Agreement to an "Article," "Section" or other subdivision or to an "Attachment" or other schedule or attachment shall be references to an article, section or other subdivision of, or to a schedule or attachment to, this Agreement, unless otherwise stated, and all such Articles, Sections, and Attachments are incorporated into this Agreement by reference (all of which comprise part of one and the same agreement with equal force and effect). In the event of any conflict or other inconsistency between the main body of this Agreement and any attachment or schedule to this Agreement, the provisions of the main body of this Agreement shall prevail.

Section 1.2.6. Subsequent Acts. Any references in this Agreement to any statute shall be deemed to refer to such statute, as amended or replaced from time to time, including by succession of comparable successor statute, and all rules and regulations promulgated thereunder. In the event any index or publication referenced in this Agreement ceases to be published or a concept defined by reference to any such index or publication ceases to exist, each such reference shall be deemed to be a reference to a successor or alternate index, publication or concept reasonably agreed to by the Parties. Unless specified otherwise, a reference to a given agreement or instrument, and all schedules and attachments thereto, shall be a reference to that agreement or instrument as modified, amended, supplemented and restated, and as in effect from time to time.

Section 1.2.7. Inclusive of Permitted Successors. Unless otherwise expressly stated, references to any Person also include its permitted successors and assigns.

Section 1.2.8. Time Computation. In this Agreement, in the computation of periods of time from a specified date to a later specified date, the word "from" means "from and including" and the words "to" and "until" each means "to but excluding."

Section 1.2.9. Business Days. Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken under this Agreement on or by a day that is not a Business Day, such action may be validly taken on or by the next day that is a Business Day, and in the case of payments (including refunds of payments), no interest shall accrue on the amount due; provided that such payment is made in full on the next day that is a Business Day.

Section 1.2.10. Regulatory Approvals. Any Governmental Approval shall be deemed to be received upon issuance, even if such Governmental Approval is subject to appeal or rehearing.

Section 1.2.11. Currency. All references to prices, values or monetary amounts referred to in this Agreement shall be paid in United States currency, unless expressly provided otherwise.

ARTICLE 2

REGULATORY FILINGS AND REQUIRED APPROVALS

Section 2.1. FERC Filing.

(a) As soon as practicable after the Execution Date, but in no event later than sixty (60) days thereafter, Owner shall file this Agreement with FERC pursuant to Section 205 of the Federal Power Act and 18 C.F.R. Part 35. Such filing shall include waiver requests for the Effective Date to occur sixty-one (61) days after the date of such filing, which Effective Date may be more than one hundred twenty (120) days before the Commercial Operation Date.

(b) Owner shall consult with Purchaser as to the appropriate time of such filing. The Parties shall respond promptly to any requests for additional information made by FERC in connection with such filing.

(c) Upon the filing of this Agreement pursuant to Section 2.1(a), Purchaser shall support the approval or acceptance of this Agreement by FERC without modification or condition.

Section 2.2. Modifications to FERC Order.

(a) In the event (i) FERC issues an order accepting or approving this Agreement for filing (the "FERC Order") and (ii) the FERC Order contains modifications or conditions that are unacceptable to a Party, in its sole discretion (an "Unfavorable FERC Decision"), such Party shall deliver a written notice to the other Party specifying the unacceptable modifications or conditions, which notice shall be delivered within five (5) Business Days following the issuance of the Unfavorable FERC Decision.

(b) In the event of an Unfavorable FERC Decision, the following provisions shall apply:

(i) The Parties may agree upon amendments to this Agreement (the "FERC Amendment") that achieve, as nearly as practicable, the commercial intent of this Agreement as of the Execution Date in a manner consistent with the Unfavorable FERC Decision. The execution and delivery by the Parties of a FERC Amendment shall be without prejudice to either Party's rights under Section 3.3.2.

(ii) Each Party shall retain the right to request a rehearing of the FERC Order regardless of any negotiations that have occurred or are occurring pursuant to clause (b)(i) above; provided, however, that, in the event the Parties execute a FERC Amendment after one or both of the Parties has filed for rehearing, any such rehearing request shall be withdrawn no later than five (5) Business Days after FERC issues an order accepting or approving the FERC Amendment for filing, if such rehearing request is inconsistent with the terms and conditions of this Agreement, as amended. Unless otherwise agreed in writing by the Parties, a filing by either Party of a request for rehearing of the FERC Order shall not toll or otherwise modify any date or time period set forth in this Agreement, including, for the avoidance of doubt, the date upon which the Construction Phase shall commence or the period within which a Party may terminate this Agreement under Section 3.3.2.

Section 2.3. Cooperation.

(a) In addition to their obligations under Section 2.1, Owner and Purchaser shall, and each Party shall use commercially reasonable efforts to cause its Affiliates to, (i) cooperate with each other to prepare, file and effect any applications, notices, petitions, reports or other filings or documentation required under Applicable Law or otherwise necessary, proper or advisable to consummate the transactions contemplated by this Agreement, (ii) provide updates to the other Party on material developments in connection with any such filings or documentation, (iii) provide any non-privileged information reasonably requested by the other Party in connection with any such filings or documentation, (iv) cooperate with each other to use commercially reasonable efforts to obtain all Governmental Approvals and Third Party Consents that are necessary, proper or advisable to consummate the transactions contemplated by this Agreement, including the FERC Order (without modifications or conditions) and the other Owner Approvals, and (v) provide any support reasonably necessary and requested by the AC Upgrade Owners to obtain the AC Upgrade Approvals.

(b) Each Party shall consult with the Management Committee with respect to all characterizations of information relating to the other Party, its Affiliates or the transactions contemplated by this Agreement that are proposed to appear in any filings or documentation contemplated by Section 2.1 or Section 2.3(a). The Management Committee shall promptly provide comments, if any, to the applicable Party on any such characterizations of information. Each Party shall make a good faith effort to take into account any comments made by the Management Committee.

Section 2.4. No Inconsistent Action. Except as provided in Section 18.2 and Article 20, from and after the Execution Date, the Parties shall not undertake, and shall use commercially reasonable efforts to cause their Affiliates not to undertake, any action before FERC, ISO-NE or any other Governmental Authority that is inconsistent with the terms and conditions of this Agreement, including, for the avoidance of doubt, Section 2.1(c) and Section 7.1.5.

ARTICLE 3

EFFECTIVE DATE; TERM

Section 3.1. Effective Date. This Agreement shall become effective and enforceable to the extent permitted by Applicable Law as of the Execution Date. Notwithstanding the foregoing sentence, this Agreement will become effective as a FERC rate schedule upon the effective date set forth in the FERC Order (the "Effective Date").

Section 3.2. Term. The term of this Agreement shall commence on the Execution Date and shall expire on the fortieth (40th) anniversary of the Commercial Operation Date, unless earlier terminated or extended in accordance with the terms hereof (the "Term").

Section 3.3. Termination Rights. This Agreement may be terminated in accordance with the ensuing provisions in this Article 3, subject to any required regulatory review, approvals or acceptances, as applicable. Neither Party shall oppose any termination of this Agreement made in accordance with this Article 3 before FERC or any other Governmental Authority; provided, however, that the foregoing shall not prohibit either Party from challenging or otherwise Disputing whether or not any termination of this Agreement is permitted by this Agreement.

Section 3.3.1. Mutual Agreement. This Agreement may be terminated at any time upon written agreement of the Parties.

Section 3.3.2. For Convenience During the Development Phase.

(a) Prior to the commencement of the Construction Phase, either Party shall have the right to terminate this Agreement by written notice to the other Party. This right may be exercised by either Party for any reason, including, for the avoidance of doubt, an Unfavorable FERC Decision, Third Party Rehearing Request, Impasse or other Dispute with respect to the Preliminary Budget and Schedule (or any part thereof) or failure by Owner and Affiliates of Purchaser to execute term sheets for a Construction Contract or the Construction Loan Agreement.

(b) Except as otherwise provided in Section 3.6, upon termination of this Agreement pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement; provided, however, that, subject to FERC approval, Purchaser shall reimburse Owner for costs and expenses incurred by Owner to the extent provided in, and in accordance with, the Letter Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.2, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.3. U.S. Regulatory Event.

(a) During the Construction Phase, at any time prior to the fifteenth (15th) day after the receipt by Owner or its Affiliates of all Construction Authorizations, Owner shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Purchaser in the event of a U.S. Regulatory Event.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs, less EPC Costs (if any); provided, however, that, if (i) this Agreement has been terminated pursuant to clause (a) above and (ii) Owner has failed to comply with the provisions of Section 5.1.2(a)(ii)(A), then, except as otherwise provided in Section 3.6, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.3, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.4. Canadian Regulatory Event or Other Regulatory Event.

(a) During the Construction Phase, at any time prior to the fifteenth (15th) day after the earlier to occur of (i) the receipt by Purchaser or its Affiliates of all Canadian Approvals and the receipt by Owner or an Affiliate of Purchaser of all Operational Approvals and (ii) the Approval Deadline, Purchaser shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Owner in the event of a Canadian Regulatory Event or Other Regulatory Event; provided that (A) Purchaser and any of its Affiliates that are responsible for obtaining any Canadian Approval or jointly obtaining the NPCC Approval shall have used commercially reasonable efforts to obtain all of the Canadian Approvals and to jointly obtain the NPCC Approval, in each case, by the Approval Deadline and (B) Purchaser and its Affiliates shall have cooperated with Owner in a manner consistent with Section 2.3 to obtain the ISO-NE Approval by the Approval Deadline.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.4, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.5. Failure to Obtain Certain Approvals.

(a) Unless otherwise agreed in writing by the Parties, this Agreement shall terminate immediately without further action of the Parties in the event any of the Construction Authorizations, AC Upgrade Approvals or Operational Approvals has not been obtained by the Approval Deadline.

(b) From and after the Approval Deadline, at any time prior to the receipt by Purchaser or its Affiliates of all Canadian Approvals, Owner shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Purchaser.

(c) Upon termination of this Agreement pursuant to clause (a) or (b) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC; provided, however, that, if (i) this Agreement has been terminated pursuant to clause (a) above and (ii) Owner has failed to comply with the provisions of Section 5.1.2(a)(ii), then, except as otherwise provided in Section 3.6, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.5, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.6. Material Cost Escalation.

(a) In the event the aggregate amount budgeted for Project Costs, as set forth in a proposed Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i), exceeds, by more than fifteen percent (15%), the aggregate amount budgeted for Project Costs in the most recently approved Construction Budget and Schedule, or, for the initial Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2, the aggregate amount budgeted for Project Costs in the Preliminary Budget and Schedule, Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such proposed Construction Budget and Schedule.

(b) In the event the aggregate amount budgeted for Project Costs, as set forth in a proposed Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i), exceeds, by more than thirty percent (30%), the aggregate amount budgeted for Project Costs in the Preliminary Budget and Schedule, Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such proposed Construction Budget and Schedule.

(c) Purchaser's failure to exercise either of its termination rights pursuant to this Section 3.3.6, (or Purchaser's failure to exercise either of such rights in a timely manner) shall be without prejudice to Purchaser's right to terminate this Agreement (i) pursuant to clause (a) above in the event any proposed Construction Budget and Schedule subsequently delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i) exceeds the most recently approved Construction Budget and Schedule by more than fifteen percent (15%) or (ii) pursuant to clause (b) above in the event any proposed Construction Budget and Schedule subsequently delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i) exceeds both (A) the Preliminary Budget and Schedule by more than thirty percent (30%) and (B) the most recently approved Construction Budget and Schedule by any amount.

(d) Upon termination of this Agreement pursuant to this Section 3.3.6, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.6, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.7. Termination of Agreements with Purchaser's Affiliates.

(a) In the event (i) any Construction Contract with Hydro-Québec Contractor is terminated as a result of any default by Owner of its obligations thereunder (provided that such default was not due to a breach by Hydro-Québec Lender of its funding obligation under the Construction Loan Agreement) or (ii) the Construction Loan Agreement is terminated as a result of any default by Owner of its obligations thereunder (provided that such default was not due to a breach by Hydro-Québec Contractor of any of its obligations under a Construction Contract), Purchaser shall have the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice.

(b) Except as otherwise provided in Section 3.6, upon termination of this Agreement pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.7, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.8. For Convenience During Construction Phase.

(a) In addition to the termination rights set forth in Section 3.3.4 and Section 3.3.6, during the Construction Phase, Purchaser shall have the right to terminate this Agreement for any other reason by not less than five (5) days' prior written notice to Owner.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC.

The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.8, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.9. Loss Occurrence Following Commercial Operation.

(a) In the event (i) a Loss Occurrence during the Operation Phase renders the Northern Pass Transmission Line entirely out-of-service and (ii) the projected Reconstruction Costs, as set forth in the proposed Reconstruction Plan delivered to the

Management Committee under Section 16.3(c)(i), exceed, in the aggregate, the amount equal to (A) the unamortized rate base, as set forth in the Rate Base Calculation delivered to the Management Committee under Section 16.3(c)(i), multiplied by (B) fifteen one-hundredths (0.15), Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such Reconstruction Plan and Rate Base Calculation.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.9, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

Section 3.3.10. For Convenience Following Commercial Operation.

(a) In addition to the termination rights set forth in Section 3.3.9 and Section 3.3.12, from and after the Commercial Operation Date, Purchaser shall have the right to terminate this Agreement for any other reason by not less than thirty (30) days' prior written notice to Owner.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Termination Payment; provided, however, that if this Agreement has been terminated pursuant to clause (a) above within sixty (60) days after the receipt by Purchaser's Manager of a proposed Reconstruction Plan and Rate Base Calculation, then Purchaser shall have the right to Dispute such Reconstruction Plan or Rate Base Calculation pursuant to the arbitration provisions set forth in Section 18.3. If Purchaser Disputes such Reconstruction Plan or Rate Base Calculation, as described above, then the following provisions shall apply:

(i) In the event any such Dispute is resolved in favor of Purchaser, and the projected Reconstruction Costs, as set forth in the Reconstruction Plan delivered to the Management Committee under Section 16.3(c)(i) (or determined pursuant to the arbitration provisions set forth in Section 18.3 in the event of an Impasse with respect thereto), exceed, in the aggregate, the amount equal to (A) the unamortized rate base, as set forth in the Rate Base Calculation delivered to the Management Committee under Section 16.3(c)(i) (or determined pursuant to the arbitration provisions set forth in Section 18.3 in the event of an Impasse with respect thereto), multiplied by (B) fifteen one-hundredths (0.15), then, in lieu of the Termination Payment, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC.

(ii) In the event clause (b)(i) above does not apply following resolution of any such Dispute, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Termination Payment.

The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.10, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

Section 3.3.11. Purchaser Default.

(a) Owner shall have the right to terminate this Agreement in accordance with Section 15.3(a).

(b) Upon the exercise by Owner of its termination rights pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Termination Payment. The Parties' rights and obligations, following termination of this Agreement pursuant to clause (a) above, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

(c) The exercise by Owner of its termination rights pursuant to clause (a) above shall constitute a waiver by Owner of all other remedies or damages that may be available at law or in equity; provided, however, that Owner shall not waive its right to, and Purchaser shall remain liable for, the Termination Payment, any amounts owed to Owner by Purchaser under Section 3.4, Section 9.3.3(c), Section 9.3.4 or Section 9.3.5(d) and any indemnification obligations of Purchaser to Owner under this Agreement, together with any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover the Termination Payment or such indemnified or other amounts.

Section 3.3.12. Owner Default.

(a) Purchaser shall have the right to terminate this Agreement in accordance with Section 15.4(a), Section 15.4(c) or Section 15.4(d).

(b) Except as otherwise provided in Section 3.6, upon the exercise by Purchaser of its termination rights pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to clause (a) above, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(c) and Section 9.3.

(c) The exercise by Purchaser of its termination rights pursuant to clause (a) above shall constitute a waiver by Purchaser of all other remedies or damages that may be available at law or in equity; provided, however, that Purchaser shall not waive its right to, and Owner shall remain liable for, any express remedy or measure of damages that are owing to Purchaser or any express modification of Purchaser's payment obligations that have accrued under this Agreement before or as of such termination, any amounts owed to Purchaser by Owner under Section 9.2, Section 9.3.3(d) or Section 9.3.4, any fees and expenses reasonably incurred by Purchaser in enforcing Owner's participation obligation pursuant to

Section 18.3.5 and any indemnification obligations of Owner to Purchaser under this Agreement, together with any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover such damages or such indemnified or other amounts owed to Purchaser by Owner.

Section 3.4. Termination Payments.

(a) Within sixty (60) days following the termination of this Agreement pursuant to Section 3.3, Owner shall deliver to Purchaser a preliminary invoice that sets forth Owner's good faith estimate of the amounts owed to Owner by Purchaser under Section 3.3, as such amounts may be adjusted pursuant to clause (c) below. Purchaser shall pay the amounts set forth in such preliminary invoice within thirty (30) days following its receipt of such preliminary invoice but otherwise in a manner consistent with Section 14.1.

(b) Promptly after the actual amounts owed to Owner by Purchaser under Section 3.3 are known to Owner, but no later than thirty (30) days following the end of the work associated with the Decommissioning of the Northern Pass Transmission Line, Owner shall deliver to Purchaser a final invoice reconciling the estimated amounts owed to Owner by Purchaser under Section 3.3 and paid by Purchaser with the actual amounts owed to Owner by Purchaser under Section 3.3. If and to the extent the total amount paid by Purchaser for the estimated amounts owed to Owner by Purchaser under Section 3.3 is greater than the actual amounts owed to Owner by Purchaser under Section 3.3, then, concurrently with the delivery of such final invoice, Owner shall refund to Purchaser the excess amounts collected, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the total amount paid by Purchaser for the estimated amounts owed to Owner by Purchaser under Section 3.3 is less than the actual amounts owed to Owner by Purchaser under Section 3.3, then Purchaser shall pay a surcharge to Owner in the amount of such deficiency, together with interest thereon calculated pursuant to Section 14.5(b), in a single lump sum due thirty (30) days following the receipt by Purchaser of such final invoice but otherwise in a manner consistent with Section 14.1. Either Party may deduct and setoff payment of such refund or surcharge, as applicable, against any accrued but unpaid payment obligation of the other Party to such Party hereunder.

(c) Any payments by or on account of any obligation of Purchaser pursuant to Section 3.3 or Section 9.3 shall be made in such amounts as may be necessary for all such payments, after any reduction or withholding for or on account of any present or future taxes, levies, imposts, duties, fees, deductions, withholdings, assessments or other charges imposed, levied, or assessed by or on behalf of any Governmental Authority, and after payment by Owner of any Income Taxes with respect to such amounts (taking into account any reduction in tax or other tax benefits resulting from, or attributable to, any amounts deducted or withheld by Purchaser pursuant to this clause (c)), to yield an aggregate amount that shall not be less than the amounts that Owner was entitled to recover pursuant to Section 3.3 or Section 9.3. If any taxes, levies, imposts, duties, fees, deductions, withholdings, assessments or other charges are required by Applicable Law to be deducted or withheld by Purchaser from any amounts owed to Owner by Purchaser under Section 3.3 or Section 9.3, then (i) Purchaser shall make such deductions or withholdings, and (ii) Purchaser shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with Applicable Law. Notwithstanding anything herein to the contrary, the computation of the adjustments required pursuant to this clause (c) shall be made without duplication of any Federal Income Taxes, State Income Taxes or any other Taxes included in the definition of Owner's Costs or Decommissioning Costs, as applicable. The reconciliation process provided in clause (b) above shall apply *mutatis mutandis* to the actual adjustments required pursuant to this clause (c).

(d) The Parties acknowledge and agree that the payment of amounts by Purchaser to Owner pursuant to Section 3.3, Section 3.4 or Section 9.3 is an appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for the termination of this Agreement are difficult or impossible to determine and that the damages calculated under Section 3.3, Section 3.4 or Section 9.3 constitute a reasonable approximation of the harm or loss to Owner as a result thereof.

Section 3.5. Allocation of Property Rights and Interests Following Termination.

(a) The following provisions shall apply upon the termination of this Agreement pursuant to Section 3.3.2, Section 3.3.3, Section 3.3.4, Section 3.3.5, Section 3.3.6, Section 3.3.7 or Section 3.3.8:

(i) Owner shall have the right to retain or dispose of the Owner Retained Property.

(ii) Subject to the receipt by Owner of all amounts owed to it by Purchaser under this Agreement or the Letter Agreement, as applicable, Owner shall promptly deliver to Purchaser a copy of the Design Materials. For a period of three (3) years following the termination of this Agreement, Purchaser shall not use, or permit a third party to use, the Design Materials to develop, with any Person other than Owner or its Affiliates, an HVDC transmission line from the Province of Québec directly into or through the State of New Hampshire, without the prior written consent of Owner.

(iii) Subject to the receipt by Owner of all amounts owed to it by Purchaser under this Agreement or the Letter Agreement, as applicable, Purchaser shall have the option (exercisable by written notice to Owner) to acquire from Owner, without additional cost to Purchaser or compensation to Owner, the Project Assets. In the event Purchaser fails to exercise such option within thirty (30) days after the termination of this Agreement, Owner shall salvage all Project Assets not acquired by Purchaser pursuant to this clause (a)(iii) in accordance with Section 9.3.5(b).

(b) The following provisions shall apply upon the termination of this Agreement pursuant to Section 3.3.9, Section 3.3.10 or Section 15.3(a):

(i) Owner shall have the right to (A) subject to the rights (if any) of any Financing Party under any of the Loan Agreements, retain or dispose of the rights and interests associated with the Northern Pass Transmission Line, including, for the avoidance of doubt, the Owner Retained Property and (B) determine if and when to Decommission the Northern Pass Transmission Line; provided that the Decommissioning, when it occurs, is undertaken in accordance with Section 9.3.

(ii) Purchaser shall have no right to acquire or use any property rights and interests associated with the Northern Pass Transmission Line, except as may be provided in the Purchaser's Security Documents for any accrued but unpaid payment obligation of Owner to Purchaser hereunder.

(c) The following provisions shall apply upon the termination of this Agreement pursuant to Section 15.4(a), Section 15.4(c) or Section 15.4(d):

(i) Subject to the rights (if any) of any Financing Party under any of the Loan Agreements and the rights of Purchaser under the Purchaser's Security Documents or against Purchaser's Lien, Owner shall retain the rights and interests associated with the Northern Pass Transmission Line, including, for the avoidance of doubt, the Owner Retained Property.

(ii) Purchaser's rights with respect to the property rights and interests associated with the Northern Pass Transmission Line shall be governed by the Purchaser's Security Documents.

Section 3.6. Effect of Termination. Except as provided in Section 24.12 for the survival of provisions, upon expiration or other termination of this Agreement pursuant to its terms, each of the Parties shall be released from all of its obligations under this Agreement, other than any accrued but unpaid payment obligation. Notwithstanding the foregoing sentence, upon such expiration or termination of this Agreement, either Party shall have the right to recover any costs or expenses (including reasonable attorneys' fees) reasonably incurred by such Party to recover any amounts owed to such Party by the other Party hereunder or to secure the release of any security or performance assurance provided by or on behalf of such Party after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of such Party to the other Party hereunder shall have been fully, finally and indefeasibly satisfied.

ARTICLE 4

COMMERCIAL OPERATION

Section 4.1. Commercial Operation Date.

(a) Owner shall provide a written non-binding notice to Purchaser no later than sixty (60) days before the date Owner reasonably expects the Commercial Operation Date to occur.

(b) At the reasonable request of Owner made in writing, Purchaser shall, and shall use commercially reasonable efforts to cause its Affiliates to, cooperate with Owner, TransÉnergie and ISO-NE to support the Commissioning of the HVDC Transmission Project.

(c) As soon as practicable after Owner is of the opinion that the conditions to Commercial Operation, as set forth in Section 4.2, have been satisfied, or such conditions have been waived in writing by the Parties (except in the case of Section 4.2(b), Section 4.2(f), Section 4.2(g) and Section 4.2(h), which conditions may be waived in writing by Purchaser, in its sole discretion), Owner shall deliver a written notice to Purchaser specifying the date upon which Commercial Operation shall commence (the "COD Notice"), which commencement date shall occur no earlier than ten (10) Business Days after the receipt by Purchaser of the COD Notice or on such other date as agreed upon by the Parties in writing (such date, the "Commercial Operation Date").

(d) Within five (5) Business Days after the receipt by Purchaser of the COD Notice, Purchaser shall deliver a certificate to Owner either (i) confirming that the conditions set forth in Section 4.2 have been satisfied or duly waived and that Commercial Operation may commence on the Commercial Operation Date or (ii) objecting with reasonable detail to the COD Notice. Purchaser's failure to respond in writing to a COD Notice within such five (5)-Business Day period shall be deemed to be a confirmation that the conditions set forth in Section 4.2 have been satisfied or duly waived. Any Dispute over whether or not the conditions set forth in Section 4.2 have been satisfied or duly waived shall be resolved in accordance with Article 18. Regardless of the resolution of such Dispute, but subject to the limitations provided in Section 4.3.1(a), for purposes of cost recovery under Section 8.1.2, Owner shall have the right to continue to accrue AFUDC on the Construction Costs and Carrying Charges on the Pre-COD Expenses for the period of time pending resolution of such Dispute and until the Commercial Operation Date. Such Construction Costs and Pre-COD Expenses shall include costs and expenses that are (A) incurred by Owner before the Commercial Operation Date to maintain the Northern Pass Transmission Line in good operating condition pending resolution of such Dispute and (B) recoverable under the Formula Rate in accordance with Article 8.

Section 4.2. Conditions Precedent to Commercial Operation. The items set forth in clauses (a) through (h) below shall be conditions precedent to the Commercial Operation of the Northern Pass Transmission Line:

(a) Completion of the Commissioning of the HVDC Transmission Project by Owner (in coordination with ISO-NE) and TransÉnergie;

(b) The Northern Pass Transmission Line has been constructed in accordance with, and is capable of operating at, the Design Capability;

(c) Completion of the AC Upgrades;

(d) The Interconnection Agreements shall be in full force and effect;

(e) The Transmission Operating Agreement shall be in full force and effect and ISO-NE shall have informed Owner that ISO-NE (i) is prepared to assume operational control over the Northern Pass Transmission Line, as defined in, and in accordance with, the Transmission Operating Agreement and (ii) will assume such operational control as of the Commercial Operation Date;

(f) The Québec Line has been constructed in accordance with, and is capable of operating at, the Design Capability;

(g) Receipt by Purchaser of copies of certificates evidencing all outstanding insurance required or otherwise obtained under Section 5.3(a); and

(h) Receipt by Purchaser of an opinion of legal counsel, reasonably satisfactory to Purchaser, that all Governmental Approvals and Third Party Consents required to own and operate the Northern Pass Transmission Line have been obtained.

Section 4.3. Delay in Commercial Operation.

Section 4.3.1. Owner Delay.

(a) If, as a result of an Owner Default, any conditions set forth in Section 4.2 shall not have been satisfied or duly waived within one hundred eighty (180) days following the later to occur of (i) the Target Date and (ii) the date upon which TransÉnergie has certified to Owner in good faith that the Québec Line is ready for Commissioning (such delay, an "Owner Delay," and such one hundred eightieth (180th) day, "Owner's Initial Deadline"), then, for purposes of cost recovery under Section 8.1.2, AFUDC shall not be accrued on the Construction Costs and Carrying Charges shall not be accrued on the Pre-COD Expenses, in each case, from and after Owner's Initial Deadline.

(b) If an Owner Delay continues beyond the second (2nd) anniversary of Owner's Initial Deadline ("Owner's Final Deadline"), then the following provisions shall also apply:

(i) Purchaser shall have the right to recover from Owner, and Owner shall pay or reimburse to Purchaser, for each month (or part thereof) following Owner's Final Deadline during which the Owner Delay is continuing, an amount equal to all penalties, damages, fees or other charges in respect of the Québec Line that are owed and paid by HQP to TransÉnergie, if any, under the TransÉnergie OATT with respect to such month (or part thereof); provided, however, that Owner's maximum liability to Purchaser under this clause (b)(i) shall not exceed, in the aggregate, an amount equivalent to the sum of the transmission service payments in respect of the Québec Line that would have been owed by HQP to TransÉnergie under the TransÉnergie OATT (the "OATT Payments") (exclusive of any penalties, damages, fees or other charges) if the Québec Line was operating at its full expected capacity following its commercial operation for the period commencing on Owner's Final Deadline and ending six (6) months thereafter or upon the earlier termination of this Agreement pursuant to its terms. Any such penalties, damages, fees or other charges, when taken as a whole, shall not exceed the amounts that would have been owed by a Person other than an Affiliate of TransÉnergie in a comparable arm's-length transaction or arrangement under the TransÉnergie OATT. Purchaser shall use commercially reasonable efforts to cause HQP to mitigate the amount of any such penalties, damages, fees or other charges. At Owner's reasonable request, Purchaser shall make available to Owner any information reasonably necessary to support the amounts owed to Purchaser by Owner pursuant to this clause (b)(i).

(ii) The Parties acknowledge and agree that the cessation of the accrual of AFUDC on Construction Costs and Carrying Charges on Pre-COD Expenses, in each case, pursuant to clause (a) above and the payment of amounts by Owner to Purchaser under clause (b)(i) above are an appropriate remedy and that any such modification or payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for an Owner Delay are difficult or impossible to determine and that the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Purchaser as a result thereof.

(iii) Subject to the discharge by Owner of its obligations under Section 5.7(a), the rights provided in Section 3.3.12 and this Section 4.3.1 shall collectively be the sole and exclusive remedy of Purchaser with respect to an Owner Delay. The foregoing sentence shall not be construed in any way to limit (A) Purchaser’s right to recover any costs or expenses (including reasonable attorneys’ fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement, (B) Purchaser’s rights and remedies under the Purchaser’s Security Documents or Owner Guaranty or against Purchaser’s Lien or any other financial assurances held by Purchaser or (C) Purchaser’s right to recover payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2.

Section 4.3.2. Other Delays. If, for any reason other than an Owner Default, any conditions set forth in Section 4.2 shall not have been satisfied or duly waived by the date upon which Owner has certified to Purchaser in good faith that the Northern Pass Transmission Line is ready for Commissioning, then the following provisions shall apply:

(a) For purposes of cost recovery under Section 8.1.2, AFUDC shall continue to be accrued on the Construction Costs and Carrying Charges shall continue to be accrued on the Pre-COD Expenses, as provided in Section 8.1.2(e)(ii) and Section 8.1.2(e)(iii), in each case, during the period of delay during which any conditions set forth in Section 4.2 have yet to be satisfied or duly waived.

(b) If such delay continues beyond the second (2nd) anniversary of the later to occur of (i) the Target Date and (ii) the date upon which Owner has certified to Purchaser in good faith that the Northern Pass Transmission Line is ready for Commissioning (such second (2nd) anniversary date, "Purchaser’s Deadline"), then the Commercial Operation Date shall be deemed to have occurred, and the Operation Phase shall be deemed to have commenced, on Purchaser’s Deadline for all purposes under this Agreement (provided this Agreement has not been terminated), and Purchaser shall commence payments of the Transmission Service Payments in accordance with Article 14 as if the Northern Pass Transmission Line had achieved Commercial Operation.

(c) For the avoidance of doubt, during such period of delay at any time before Purchaser’s Deadline, Purchaser shall continue to have the right to terminate this Agreement under Section 3.3.8, and, from and after Purchaser's Deadline, Purchaser shall have the right to terminate this Agreement under Section 3.3.10.

ARTICLE 5

GENERAL RIGHTS AND RESPONSIBILITIES OF THE PARTIES

Section 5.1. Responsibilities of the Parties.

Section 5.1.1. Development Phase. The Parties acknowledge and agree that Owner, either directly or through its Affiliates, has commenced the development of the technical design and scope of the Northern Pass Transmission Line consistent with the scope of activities defined in, and the monthly reports and budgets provided under, the Letter Agreement.

Section 5.1.2. Construction Phase.

(a) During the Construction Phase, Owner shall (i) exercise Good Utility Practice to complete, or cause the completion of, all tasks required to construct the Northern Pass Transmission Line and achieve Commercial Operation by the Target Date, in each case, in accordance with the Design Capability and in a manner consistent with Attachment A, (ii) use commercially reasonable efforts (A) to obtain all of the Construction Authorizations by the Approval Deadline, (B) to obtain, jointly with TransÉnergie, the NPCC Approval by the Approval Deadline, (C) to obtain, in consultation with Purchaser or Purchaser's Affiliates, the ISO-NE Approval by the Approval Deadline and (D) to cause Owner's Affiliates that are AC Upgrade Owners to obtain any AC Upgrade Approvals for which such Affiliates are responsible by the Approval Deadline, and (iii) use commercially reasonable efforts to obtain all Owner Approvals (other than the Construction Authorizations) by the Target Date. Provided that Owner has complied with its obligations under Section 2.1, Section 2.3, Section 5.1.2(a)(ii) and Section 5.1.2(a)(iii), Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of Owner's failure to obtain an Owner Approval or an Operational Approval or any AC Upgrade Owner's failure to obtain an AC Upgrade Approval.

(b) The Parties intend that Owner and Hydro-Québec Contractor will use commercially reasonable efforts to enter into, within a commercially reasonable timeframe, a Construction Contract on terms and conditions that are customary for the engineering, procurement and construction of projects of a similar nature to the Northern Pass Transmission Line, but also giving due consideration to the particular context and structure of the transactions contemplated hereby and thereby. The Parties also intend that Owner and Hydro-Québec Lender will use commercially reasonable efforts to enter into, within a commercially reasonable timeframe, the Construction Loan Agreement on terms and conditions that are customary for fully secured project financings of a similar nature to the Northern Pass Transmission Line, but also giving due consideration to the particular context and structure of the transactions contemplated hereby and thereby.

(c) At Purchaser's reasonable request made in writing, Owner shall, and shall use commercially reasonable efforts to cause its Affiliates to, support and cooperate with Purchaser in order to enable Purchaser to enter into one or more facilities agreements to pay for the costs to design, license, construct and operate the Additional AC Upgrades.

(d) Owner shall cooperate with Purchaser and its Affiliates as reasonably necessary for Purchaser or its Affiliates to obtain the Export Authorizations related to the Northern Pass Transmission Line.

(e) The following provisions shall apply with respect to a Term Financing:

(i) No later than three hundred sixty-five (365) days before the Target Date, or such other date as the Management Committee may approve, the Management Committee shall establish a timetable, procedures (the "Term Financing Procedures") and Term Financing Parameters for a Term Financing to refinance the Construction Loan Agreement. No later than three hundred sixty-five (365) days before the maturity date of any Term Financing, the Management Committee shall establish a timetable, Term Financing Procedures and Term Financing Parameters for the refinancing of such Term Financing.

(ii) The Term Financing Parameters shall include a requirement that the Term Financing be on terms and conditions that are customary for fully secured project financings of a similar nature to the Northern Pass Transmission Line, but in no event shall the Term Financing Procedures include any obligation for any Affiliate of Owner to provide a guaranty, capital funds commitment or similar support agreement. The Term Financing Procedures shall require Owner to seek a minimum number of competitive bids (which may be in the form of proposals or commitment letters as specified in the Term Financing Procedures) from potential lenders and shall permit Purchaser or one or more of its Affiliates to submit a competitive bid for the Term Financing. In recognition that the costs of the Term Financing are recoverable under the Formula Rate in accordance with Article 8, the Term Financing Procedures shall also require that Owner negotiate the pricing terms of all or a minimum number of competitive bids for the Term Financing (including interest, fees, amortization and tenor) in good faith as though Owner were bearing such costs itself. Subject to the immediately ensuing sentence, Owner shall comply in all material respects with the timetable, Term Financing Procedures and Term Financing Parameters for the initial Term Financing or any subsequent Term Financing. If, as a result of market conditions, Owner is reasonably unable to comply with such timetable, Term Financing Procedures or Term Financing Parameters, Owner shall consult with the Management Committee, and the Management Committee shall appropriately revise the timetable, Term Financing Procedures or Term Financing Parameters, as applicable, consistent with such market conditions.

(iii) Purchaser shall have the right to review the Term Loan Agreement prior to its execution and effectiveness to confirm that the terms and conditions thereof are not in conflict in any material respect with the Term Financing Parameters established or revised by the Management Committee.

(iv) Owner shall not enter into any subsequent amendment or other modification with respect to any Term Financing that would materially increase the costs recoverable from Purchaser under this Agreement unless approved by the Management Committee.

(v) Any Impasse under this Section 5.1.2(e) shall be resolved pursuant to the arbitration provisions set forth in Section 18.3, but any such resolution shall be consistent with the terms of this Section 5.1.2(e).

Section 5.2. Budgets and Reports.

Section 5.2.1. Preliminary Budget and Schedule.

(a) Within forty-five (45) days after the Execution Date, Owner shall prepare and submit to the Management Committee for review and approval a Project Budget and Project Schedule (together, as established herein, the "Preliminary Budget and Schedule"), together with a Cost-of-Service Estimate. At the request of Purchaser's Manager, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of the proposed Preliminary Budget and Schedule, and shall make the personnel responsible for preparing such Preliminary Budget and Schedule available during normal business hours and upon reasonable advance notice to discuss such Preliminary Budget and Schedule with the Management Committee. At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning the Cost-of-Service Estimate.

(b) The Management Committee shall promptly review the proposed Preliminary Budget and Schedule, and may approve such Preliminary Budget and Schedule in whole or in part. If an Impasse occurs with respect to the proposed Preliminary Budget and Schedule (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.2, the proposed Preliminary Budget and Schedule, with any changes agreed upon by the Management Committee, shall be deemed to be (i) in effect upon the commencement of the Construction Phase and (ii) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

Section 5.2.2. Construction Budget and Schedule.

(a) On a quarterly basis beginning in the fourth (4^{th}) full calendar month during the Construction Phase, but no later than the end of the fourth (4^{th}) calendar month after the receipt by Purchaser's Manager of the most recent quarterly Construction Budget and Schedule delivered to the Management Committee under this clause (a), or as required under Section 16.3(b)(i), Owner shall prepare and submit to the Management Committee for review and approval an update of the Preliminary Budget and Schedule (such updated budget and schedule as established herein, the "Construction Budget and Schedule"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of the Construction Budget and Schedule, and shall make the personnel responsible for preparing the Construction Budget and Schedule available during normal business hours and upon reasonable advance notice to discuss the proposed Construction Budget and Schedule with the Management Committee.

(b) The Management Committee shall promptly review the proposed Construction Budget and Schedule, and may approve the Construction Budget and Schedule in whole or in part. If an Impasse occurs with respect to the proposed Construction Budget and Schedule (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.6 or Section 3.3.8, as applicable, the proposed Construction Budget and Schedule, with any changes agreed upon by the Management Committee, shall be deemed to be (i) in effect upon the sixty-first (61st) day after the receipt by Purchaser's Manager of such Construction Budget and Schedule and (ii) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

Section 5.2.3. Estimated Wind-Down Costs.

(a) Beginning on the date on which the first Construction Budget and Schedule is delivered to the Management Committee under Section 5.2.2 and on an annual basis thereafter concurrently with the delivery of every fourth (4^{th}) Construction Budget and Schedule subsequently delivered to the Management Committee under Section 5.2.2, Owner shall prepare and submit to Purchaser an estimate of the Estimated Wind-Down Costs as of the Redetermination Date associated with such Construction Budget and Schedule. Owner shall provide Purchaser with access to, and copies of, all reasonably requested documentation concerning the Estimated Wind-Down Costs.

(b) If Purchaser believes that the Estimated Wind-Down Costs are incorrect or inconsistent with the standard set forth in the definition thereof, then Purchaser shall have the right to submit the matter to the Management Committee for resolution solely for the purpose of redetermining the Determined Cap during the Construction Phase, as contemplated by Section 17.1.1(d). If an Impasse occurs with respect to such matter, then the matter shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Construction Phase, as contemplated by Section 17.1.1(d).

Section 5.2.4. Budget Overruns; Progress Reports.

(a) Owner shall use commercially reasonable efforts not to exceed the budgeted amounts set forth in the Preliminary Budget and Schedule or applicable Construction Budget and Schedule; provided, however, that all Project Costs (and Reconstruction Costs, if applicable) actually incurred by Owner, whether or not set forth in such Preliminary Budget and Schedule or applicable Construction Budget and Schedule, shall be recoverable under the Formula Rate in accordance with Article 8.

(b) Owner shall prepare and submit to the Management Committee for review during each calendar month during the Construction Phase a progress report for informational purposes that sets forth in reasonable detail (i) the Project Costs actually incurred in the prior month and the activities associated therewith and (ii) the current status of the milestones set forth in the Construction Budget and Schedule, including any changes in the expected timelines and the status of all Owner Approvals (collectively, the "Construction Progress Report"). At the request of Purchaser's Manager, Owner shall, or shall cause each Contractor to, provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Construction Progress Report.

(c) Owner shall, or shall cause the principal Contractor to, notify the Management Committee promptly, but in no event later than ten (10) days, after Owner, or such Contractor, becomes aware that (i) the Commercial Operation of the Northern Pass Transmission Line is not reasonably likely to occur by the Target Date or (ii) the aggregate costs and expenses required to develop, finance, design, site, construct and Commission the Northern Pass Transmission Line and the AC Upgrades are reasonably likely to exceed either of the minimum thresholds needed for Purchaser to terminate this Agreement under Section 3.3.6.

Section 5.3. Insurance and Events of Loss.

(a) Owner shall obtain and maintain insurance of the type, in such amounts and on such terms as required by the Management Committee from time to time. Owner shall have the right, in its sole discretion, to obtain additional insurance (in amount or type) consistent with Good Utility Practice and shall acquire such insurance as may be required by any Financing Party. All premiums and other costs of property, liability or other insurance obtained by Owner in connection with the Northern Pass Transmission Line, or the ownership, development, engineering, construction or operation thereof, shall be recoverable under the Formula Rate in accordance with Article 8. Owner shall provide Purchaser with copies of certificates of all outstanding insurance obtained hereunder promptly after the receipt thereof by Owner.

(b) The Parties' rights and obligations, following a Loss Occurrence or other loss of, destruction of or damage to, or any condemnation of, the Northern Pass Transmission Line due to an event of Force Majeure, are set forth in Article 16.

Section 5.4. Compliance with Laws. At all times during the Term, the Parties shall comply with all Applicable Laws (including ISO-NE Rules to the extent applicable) and relevant Governmental Approvals and Third Party Consents.

Section 5.5. Third Party Contracts. At all times during the Term, Owner shall (a) discharge its obligations under and (b) administer all third-party contracts entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, in each case, in a commercially reasonable manner; provided, however, that Owner shall not be in breach of its obligations under the foregoing clause (a) if, due to a breach by Hydro-Québec Lender of its funding obligation under the Construction Loan Agreement, Owner fails to discharge any payment obligation under any such third-party contract. Provided that Owner has complied with its obligations under the foregoing sentence, Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of any act or omission by any Contractor or AC Upgrade Owner, and all increased costs, expenses, fines and penalties resulting therefrom (including reasonable attorneys' fees) shall be recoverable under the Formula Rate in accordance with Article 8.

Section 5.6. Equity Commitment. Owner shall, and hereby commits to Purchaser that it will, finance a portion of the Project Costs through contributions to the equity capital of Owner in a manner consistent with Owner's obligations under Section 8.3(a). Without limiting Owner's obligations under the foregoing sentence, Owner shall enter into an equity commitment agreement with Northeast Utilities, and shall cause Northeast Utilities to enter into such equity commitment agreement with Owner, in each case, no later than the Distribution Date, pursuant to which agreement Northeast Utilities shall commit annually during the Construction Phase to provide, either directly or through a subsidiary, equity capital consistent with Owner's obligations under the foregoing sentence, which equity commitment is expected to be based upon the amounts set forth in the Construction Budget and Schedule for the upcoming year. The Parties acknowledge and agree that such equity commitment will be used only to finance Project Costs during the Construction Phase and may not be applied towards, or accelerated to settle, any claims resulting from an Owner Default, other than pursuant to this Section 5.6. For the avoidance of doubt, Owner's rights under such equity commitment agreement shall be part of the collateral pledged to Hydro-Québec Lender to secure Owner's obligations under the Construction Loan Agreement.

Section 5.7. Owner's Obligation to Cure; Purchaser's Losses.

(a) Owner shall use commercially reasonable efforts to cure, at its own cost and expense, any Owner Default in a commercially reasonable timeframe consistent with Good Utility Practice, and no such cost or expense shall be recoverable under the Formula Rate. For the avoidance of doubt, the foregoing sentence shall apply in the event of a delay in Commercial Operation due to an Owner Delay or in the event of a Non-Excused Outage.

(b) Neither Purchaser nor its Affiliates shall be entitled to recover from Owner any losses, damages, costs or expenses related to the Québec Line or arising under the TransÉnergie OATT, except as provided in Section 4.3.1 or Section 7.4.2.

Section 5.8. Continuity of Rights and Responsibilities. Unless otherwise agreed in writing by the Parties or prohibited by Applicable Law, the Parties shall continue to provide service and honor commitments under this Agreement and continue to make payments in accordance with this Agreement pending resolution of any bona fide Impasse or other Dispute hereunder or relating hereto.

ARTICLE 6

PROCEDURES FOR OPERATION AND MAINTENANCE OF THE NORTHERN PASS TRANSMISSION LINE

Section 6.1. Transmission Operating Agreement; ISO-NE Operational Control.

(a) Prior to entering into the Transmission Operating Agreement, Owner shall consult with the Management Committee with respect to the proposed terms and conditions thereof. The Management Committee shall promptly provide comments, if any, to Owner on such terms and conditions. Owner shall make a good faith effort to take into account any comments made by the Management Committee that are consistent with FERC rules and policies.

(b) As of the Commercial Operation Date, Owner shall transfer operational control over the Northern Pass Transmission Line, as defined in the Transmission Operating Agreement, to Transmission Operator in accordance with the Transmission Operating Agreement. Owner shall provide, and shall direct its Affiliates to provide, such information as Transmission Operator may require to discharge its obligations under the Transmission Operating Agreement, and Owner shall comply with the instructions of Transmission Operator to the extent provided in the Transmission Operating Agreement and the ISO-NE Tariff. The Parties acknowledge and agree that Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of Owner's compliance with such instructions of Transmission Operator; provided that Owner did not initiate or support instructions that would otherwise breach Owner's obligations under this Agreement.

Section 6.2. Good Utility Practice; Regulatory and Reliability Requirements. From and after the Commercial Operation Date, Owner shall (a) provide Firm Transmission Service and Additional Transmission Service, (b) operate and maintain the Northern Pass Transmission Line in accordance with Good Utility Practice and in compliance with all applicable regulatory requirements, including applicable NERC and NPCC reliability standards, and (c) comply with all applicable operating instructions and manufacturers' warranties. The costs associated with the discharge by Owner of its obligations under the foregoing clauses (a), (b) and (c) shall be recoverable under the Formula Rate in accordance with Article 8.

Section 6.3. Annual Plan and Operating Budget and Multiyear Outlook.

(a) No later than one hundred twenty (120) days before the start of each Contract Year or, in the case of the first Contract Year during which Owner is obligated to provide Firm Transmission Service hereunder, no later than one hundred twenty (120) days before the date Owner reasonably expects the Commercial Operation Date to occur, Owner shall deliver to the Management Committee the Annual Plan and Operating Budget for the following Contract Year, along with a non-binding Capital Plan for the following five (5) Contract Years (a "Multiyear Outlook"). Upon request by the Management Committee, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of any Annual Plan and Operating Budget and shall make the personnel responsible for its preparation available during normal business hours and upon reasonable advance notice to discuss the proposed Annual Plan and Operating Budget with the Management Committee. Owner shall also provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning the Multiyear Outlook.

(b) The Management Committee shall attempt to agree upon the Annual Plan and Operating Budget within sixty (60) days following its receipt thereof, and the Management Committee may approve the proposed Annual Plan and Operating Budget in whole or in part.

(i) If the Management Committee approves the Annual Plan and Operating Budget (or any part thereof) the costs associated with the approved activities shall not be subject to challenge on prudence grounds under Section 8.1.4. Notwithstanding the foregoing sentence, if the costs incurred by Owner to perform any activity in an approved Annual Plan and Operating Budget exceed, in the aggregate, the amount in the approved Annual Plan and Operating Budget for such activity, Purchaser shall then have the right to challenge the prudence of the costs that exceed such approved amount pursuant to Section 8.1.4.

(ii) If Purchaser's Authorized Representative votes against the approval of all or any part of the activities set forth in the Annual Plan and Operating Budget, and Owner nonetheless performs the unapproved activities, Purchaser shall have the right to challenge the prudence of Owner's expenditures on such unapproved activities pursuant to Section 8.1.4.

(iii) If Purchaser's Authorized Representative votes against the approval of all or any part of the activities set forth in the Annual Plan and Operating Budget, and Owner thereafter chooses not to perform activities that have not been approved, Owner's failure to undertake any such activities not approved by the Management Committee shall not constitute a violation of Good Utility Practice or a breach by Owner of its obligations hereunder with respect to any such activities, and Purchaser shall have no right to recover losses or damages from, or assert any claim against, Owner as a result of such failure. In addition, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, an amount equal to any penalties assessed by FERC, NERC or any other Governmental Authority for violations of Applicable Law by Owner, its Affiliates or any of its or their third-party contractors as a result of such failure.

(iv) In the event Owner becomes aware that the aggregate O&M Costs and Planned CapEx Costs to be incurred during any Contract Year are likely to exceed the budgeted amounts therefor, as set forth in the Annual Plan and Operating Budget, by more than fifteen percent (15%), Owner shall promptly notify the Management Committee. At the request of Purchaser's Manager, Owner shall provide the Management Committee, as applicable, with access to, and copies of, all reasonably requested documentation concerning such O&M Costs or Planned CapEx Costs.

(v) The budgeted amounts for O&M Costs and Planned CapEx Costs, as set forth in any Annual Plan and Operating Budget approved by the Management Committee or otherwise contemplated by Section 6.2, shall be used to calculate Transmission Service Payments under the Formula Rate and shall be recoverable under the Formula Rate in accordance with Article 8, subject to reconciliation, as described in Section 14.2, to account for differences between the budgeted and actual O&M Costs and Planned CapEx Costs.

(c) The Management Committee shall also attempt to agree upon the Multiyear Outlook within sixty (60) days following its receipt thereof solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d), and the Management Committee may approve the proposed Multiyear Outlook in whole or in part. If an Impasse occurs with respect to the proposed Multiyear Outlook, then the Impasse shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d). The Capital Plan for any Contract Year shall not be deemed to be imprudent solely on the basis that such Capital Plan varied from any Multiyear Outlook that included such Contract Year. Purchaser shall not waive any right to challenge the prudence of any Capital Plan for any Contract Year solely on the basis that the Management Committee approved any Multiyear Outlook that included such Contract Year.

Section 6.4. Estimated Wind-Down Costs.

(a) Beginning on the date on which the first Annual Plan and Operating Budget is delivered to the Management Committee under Section 6.3 and thereafter concurrently with the delivery of every third (3rd) Annual Plan and Operating Budget subsequently delivered to the Management Committee under Section 6.3, Owner shall prepare and submit to Purchaser an estimate of the Estimated Wind-Down Costs as of the upcoming Redetermination Date. Owner shall provide Purchaser with access to, and copies of, all reasonably requested documentation concerning the Estimated Wind-Down Costs.

(b) If Purchaser believes that the Estimated Wind-Down Costs are incorrect or inconsistent with the standard set forth in the definition thereof, then Purchaser shall have the right to submit the matter to the Management Committee for resolution solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d). If an Impasse occurs with respect to such matter, then the matter shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d).

Section 6.5. Scheduled Maintenance. Unless approved by the Management Committee, or unless the Transmission Operator or TransÉnergie requires otherwise, Owner shall not perform or otherwise undertake, and shall cause third parties not to perform or otherwise undertake, any scheduled maintenance or capital project with respect to the Northern Pass Transmission Line that requires any interruption or reduction of scheduling rights over the Northern Pass Transmission Line during the months of January, February, March, June, July, August, September and December.

Section 6.6. Extraordinary Capital Expenditures.

(a) In the event Owner determines that any Extraordinary CapEx is required, Owner shall promptly notify the Management Committee and deliver to it information relating to the cost and expected scope and nature of the Extraordinary CapEx, including any expected outages and overhauls of the Northern Pass Transmission Line associated therewith (the "Extraordinary CapEx Plan"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Extraordinary CapEx Plan.

(b) The Management Committee shall attempt to agree upon any Extraordinary CapEx Plan as soon as practicable after its receipt thereof, and the Management Committee may approve the proposed Extraordinary CapEx Plan in whole or in part; provided, however, that, subject to Purchaser's rights under Section 8.1.4, no Management Committee approval shall be required for any Extraordinary CapEx Plan that does not exceed One Million Dollars ($1,000,000).

(c) Section 6.3(b)(i), Section 6.3(b)(ii) and Section 6.3(b)(iii) shall apply *mutatis mutandis* to costs incurred by Owner to perform Extraordinary CapEx that is approved or not approved by the Management Committee.

(d) Any Extraordinary CapEx Plan shall be used to calculate Transmission Service Payments under the Formula Rate and the costs set forth therein shall be recoverable under the Formula Rate in accordance with Article 8, subject to reconciliation, as described in Section 14.2, to account for differences between the budgeted and actual Extraordinary CapEx Costs.

Section 6.7. Record of Management Committee Decisions. The minutes for any meeting at which a vote was held with respect to a proposed Annual Plan and Operating Budget or Extraordinary CapEx Plan, as applicable, or any unanimous written consent in lieu thereof, shall expressly set forth in reasonable detail the grounds on which Purchaser's Authorized Representative disapproved of any maintenance or capital expenditure set forth in such Annual Plan and Operating Budget or Extraordinary CapEx Plan, as applicable, and the reasons therefor.

ARTICLE 7

PURCHASER'S TRANSMISSION RIGHTS OVER THE NORTHERN PASS TRANSMISSION LINE

Section 7.1. Transmission Service.

Section 7.1.1. Firm Transmission Service. Owner shall make available to Purchaser, from and after the Commercial Operation Date, transmission capacity on the Northern Pass Transmission Line in order to deliver electrical energy, as scheduled by Purchaser or by a third party under the resale provisions of Article 10, in an amount equal to the Contract Capacity ("Firm Transmission Service"). Firm Transmission Service shall be made available over the Northern Pass Transmission Line at any time from and after the Commercial Operation Date, in a north-to-south and south-to-north direction, between the U.S. Border and the Delivery Point. Firm Transmission Service shall be subject to curtailment or interruption only as a result of an Excused Outage or as provided in Section 15.3(b). Without limiting Owner's obligations under this Section 7.1.1, the quantity of Firm Transmission Service that Owner will provide in any hour shall not exceed the Total Transfer Capability for such hour.

Section 7.1.2. Additional Transmission Service. To the extent (a) transmission capacity in excess of the Contract Capacity in a north-to-south or south-to-north direction is necessarily incidental to the design, engineering, construction or operation of the

Northern Pass Transmission Line, as described in this Agreement, and (b) ISO-NE permits the scheduling of transmission service using such incidental transmission capacity during any hour (or such other permissible scheduling period adopted by ISO-NE), then Owner shall make available to Purchaser, from and after the Commercial Operation Date, non-firm transmission service in an amount equal to such incidental transmission capacity ("Additional Transmission Service"). Additional Transmission Service shall be subject to curtailment or interruption by ISO-NE in accordance with the ISO-NE Tariff or upon determination by the Management Committee that the provision of the Additional Transmission Service would degrade the provision of Firm Transmission Service. For the avoidance of doubt, the unavailability of, or any curtailment or interruption in, all or any portion of Additional Transmission Service shall not constitute an Excused Outage under Section 7.3 or Non-Excused Outage under Section 7.4, and any such unavailability, curtailment or interruption shall not affect the calculation of the size of any Excused Outage under Section 7.3 or Non-Excused Outage under Section 7.4.

Section 7.1.3. Limitation on Transmission Service. Owner shall have no obligation to provide transmission service under this Agreement other than Firm Transmission Service and Additional Transmission Service. Purchaser shall have no right to redirect service to alternate points of delivery or receipt on any portion of the transmission system operated by ISO-NE other than the Northern Pass Transmission Line.

Section 7.1.4. Scheduling. All Firm Transmission Service and Additional Transmission Service shall be scheduled in accordance with the rules relating to the scheduling of electrical energy or capacity transactions over the Northern Pass Transmission Line, as established under the Transmission Operating Agreement (the "Scheduling Rules").

Section 7.1.5. Owner's Cooperation.

(a) Without limiting the generality of Owner's express obligations under Section 7.1.1 and Section 7.1.2, but subject to the limitations provided in Section 11.2(c), to the extent permitted by the FERC Authorization and ISO-NE Rules and consistent with Good Utility Practice, at Purchaser's reasonable request, Owner shall cooperate with Purchaser and ISO-NE in order to permit Purchaser to realize the full reliability and economic benefits intended under this Agreement.

(b) Owner shall provide Purchaser with notice of any FERC regulatory proceedings to which Owner is a party promptly after Owner becomes aware of any such proceeding. Owner shall not take any position in such proceeding that is inconsistent with its obligations under this Agreement.

Section 7.2. Damages Under Third Party Contracts.

(a) Subject to the rights of any Financing Party, if and to the extent Owner receives or is entitled to receive damages, whether liquidated or otherwise, or other amounts payable in connection with a third party's breach of its obligations under, or termination (for whatever reason) of, any Construction Contract (including any Construction Contract with Hydro-Québec Contractor) or other contract (including any contract with the OASIS Administrator) entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, Owner shall credit the amounts received by Owner to Purchaser under the Formula Rate, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts.

(b) Owner shall use commercially reasonable efforts to pursue the collection or recovery of any such amounts and otherwise seek to enforce its rights under any Construction Contract (including any Construction Contract with Hydro-Québec Contractor), insurance policy or other third-party contract (including any contract with an Affiliate of Northeast Utilities) entered into by Owner in connection with the Northern Pass Transmission Line or the AC Upgrades.

Section 7.3. Excused Outages or Reductions.

(a) Notwithstanding anything herein to the contrary, Owner shall not be in breach of, or be liable to Purchaser for any losses or damages under, this Agreement, and no Owner Default shall occur, as a consequence of an Excused Outage. "Excused Outages" means any outages of the Northern Pass Transmission Line or reductions in the Total Transfer Capability below the Contract Capacity (whether as a result of a physical condition, legal impediment or otherwise), if and to the extent due to any reason other than Owner's failure to (i) exercise Good Utility Practice or (ii) otherwise discharge its obligations under this Agreement.

(b) For the avoidance of doubt, Excused Outages shall include outages of the Northern Pass Transmission Line or reductions in the Total Transfer Capability below the Contract Capacity due to the following events, but only to the extent they satisfy the definition set forth in last sentence of clause (a) above:

(i) Events of Force Majeure;

(ii) Scheduled maintenance, if and to the extent required to discharge Owner's obligations under Section 6.2 or Section 5.4 and consistent with Owner's obligations under Section 6.5;

(iii) Outages or reductions in the use or availability of transmission lines other than the Northern Pass Transmission Line;

(iv) Decisions of TransÉnergie or conditions in the electric system located in the Province of Québec, including the unavailability of the Québec Line, in whole or in part; and

(v) Decisions of ISO-NE, including a decision to reduce or suspend the scheduling rights over the Northern Pass Transmission Line as a result of any grid reliability issue or to preserve facilities and equipment from physical damage.

(c) Purchaser shall be obligated, during any Excused Outage, to pay the Transmission Service Payment in accordance with Article 8 and Article 14 to the same extent as if such Excused Outage had not occurred, except as provided in Section 16.4 for any Extended Outage. Owner shall use commercially reasonable efforts to (i) seek to avoid and

(ii) mitigate or remedy any Excused Outage in a commercially reasonable timeframe consistent with Good Utility Practice.

Section 7.4. Non-Excused Outages or Reductions.

Section 7.4.1. Reduction in Transmission Service Payments. Unless otherwise excused under Section 7.3 or Article 16, if and to the extent an outage of the Northern Pass Transmission Line or reduction in the Total Transfer Capability below the Contract Capacity (whether as a result of a physical condition, legal impediment or otherwise) is due to Owner's failure to (a) exercise Good Utility Practice or (b) otherwise discharge its obligations hereunder (a "Non-Excused Outage"), the Transmission Service Payment for such period shall be reduced by an amount that bears the same ratio to the Transmission Service Payment as the amount of unavailable transmission capacity resulting from such Non-Excused Outage bears to the Contract Capacity and Owner shall have no right to recover such amounts. Any Dispute over whether or not or to what extent a Non-Excused Outage has occurred shall be resolved in accordance with Article 18. For the avoidance of doubt, pending resolution of any such Dispute, Purchaser's right, pursuant to this Section 7.4.1, to any reduction in the Transmission Service Payments shall be suspended.

Section 7.4.2. Québec Damages. In addition to the reduction in Transmission Service Payments contemplated by Section 7.4.1, Purchaser shall have the right to recover from Owner, and Owner shall pay or reimburse to Purchaser, for each month (or part thereof) of any Non-Excused Outage, an amount equal to the OATT Payment with respect to such month (or part thereof) or, to the extent Purchaser acquires replacement transmission service during such month (or part thereof), the Replacement Transmission Cost for the replaced transmission capacity, if less expensive than such OATT Payment (the "Québec Damages"); provided, however, that Owner's liability to Purchaser for any Québec Damages shall not commence unless and until such time as the aggregate amount of unavailable transmission capacity resulting from Non-Excused Outages (which amount shall be converted to, and expressed in, megawatt-hours) exceeds the Initial Allowance in any Contract Year; provided, further, however, that, with respect to any Non-Excused Outage, Owner's maximum liability to Purchaser for any Québec Damages that are related to such Non-Excused Outage (regardless of the duration of such Non-Excused Outage) shall not exceed, in the aggregate, an amount equivalent to the sum of the OATT Payments for the period commencing on the later to occur of (i) the first date of such Non-Excused Outage and (ii) the date on which the aggregate amount of unavailable transmission capacity that is attributable to Non-Excused Outages (expressed in megawatt-hours) exceeds the Initial Allowance in any Contract Year and ending six (6) months thereafter or upon the earlier termination of this Agreement pursuant to its terms. Any such Québec Damages, when taken as a whole, shall not exceed the amounts that would have been owed by a Person other than an Affiliate of TransÉnergie in a comparable arm's-length transaction or arrangement under the TransÉnergie OATT. Purchaser shall use commercially reasonable efforts to cause HQP to mitigate the amount of any Québec Damages. At Owner's reasonable request, Purchaser shall make available to Owner any information reasonably necessary to support the amounts owed to Purchaser by Owner pursuant to this Section 7.4.2.

Section 7.4.3. Liquidated Damages. The Parties acknowledge and agree that the modification of Purchaser's payment obligations pursuant to Section 7.4.1 and the payment of amounts by Owner to Purchaser under Section 7.4.2 are an appropriate remedy and that any such modification or payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for a Non-Excused Outage are difficult or impossible to determine and that the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Purchaser as a result thereof.

Section 7.4.4. Sole and Exclusive Remedy. Subject to the discharge by Owner of its obligations under Section 5.7(a), the rights provided in Section 3.3.12 and this Section 7.4 shall collectively be the sole and exclusive remedy of Purchaser with respect to a Non-Excused Outage. The foregoing sentence shall not be construed in any way to limit (a) Purchaser's right to recover any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement, (b) Purchaser's rights and remedies under the Purchaser's Security Documents or Owner Guaranty or against Purchaser's Lien or any other financial assurances held by Purchaser or (c) Purchaser's right to recover payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2.

Section 7.5. Metering. Metering and telemetering requirements for the Northern Pass Transmission Line shall be established by the Management Committee in accordance with Good Utility Practice and as necessary to (a) accomplish the purposes of, and to implement and administer, this Agreement and (b) satisfy the requirements of, and to implement and administer, the Interconnection Agreement and the Transmission Operating Agreement. If an Impasse occurs with respect to such metering and telemetering requirements, then the matter shall be resolved in accordance with Section 18.1(b). All costs incurred by Owner in connection with metering and telemetering for the Northern Pass Transmission Line shall be recoverable under the Formula Rate in accordance with Article 8.

ARTICLE 8

PAYMENT FOR TRANSMISSION SERVICE OVER THE NORTHERN PASS TRANSMISSION LINE

Section 8.1. Transmission Service Payment; Application of Formula Rate.

Section 8.1.1. Letter Agreement. In the event this Agreement is terminated under Section 3.3.2, Owner's right to recover from Purchaser any costs or expenses incurred by Owner in connection with the Northern Pass Transmission Line shall be as provided in the Letter Agreement and subject to FERC approval, and Purchaser shall have no obligation for any charges under this Agreement (other than as provided in the Letter Agreement).

Section 8.1.2. Charges under the Formula Rate.

(a) Prior to the Commercial Operation Date, Owner shall not invoice Purchaser for any Transmission Service Payments hereunder.

(b) From and after the Commercial Operation Date, unless expressly excluded under the terms and conditions of this Agreement, Purchaser shall pay all charges, as calculated pursuant to the Formula Rate, which charges shall be payable on a monthly basis in accordance with Article 14 (the "Transmission Service Payment"). Owner shall not invoice Purchaser for, and Purchaser shall have no obligation to pay, any charges that are not recoverable under the Formula Rate, except (i) as contemplated by Section 8.1.1, (ii) for amounts owed to Owner by Purchaser under Section 3.3, Section 3.4, Section 9.3.3(c), Section 9.3.4 or Section 9.3.5(d), (iii) for damages that may be recovered by Owner under this Agreement as a result of a Purchaser Default, (iv) for any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover any amounts owed to Owner by Purchaser under this Agreement or to secure the release of Purchaser's Lien and the Purchaser's Security Documents or other security or performance assurance provided by or on behalf of Owner after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of Owner to Purchaser hereunder shall have been fully, finally and indefeasibly satisfied, (v) for fees and expenses reasonably incurred by Owner in enforcing Purchaser's participation obligation pursuant to Section 18.3.5, or (vi) for payment of any indemnification obligations of Purchaser to Owner pursuant to Section 21.1.

(c) Transmission Service Payments calculated under the Formula Rate shall be based upon a projected cost-of-service calculation. The Formula Rate shall be reconciled with actual costs on an annual basis in accordance with Section 14.2.

(d) If and when the Construction Phase occurs, the Letter Agreement shall terminate immediately without further action of the Parties, and commencing on the Commercial Operation Date, (i) all Construction Costs incurred during the Development Phase shall be included in the Formula Rate, together with AFUDC, as accrued thereon in accordance with clause (e)(ii) below, but subject to Section 4.3.1, and (ii) all Pre-COD Expenses shall be included in the Formula Rate, together with Carrying Charges, as accrued thereon in accordance with clause (e)(iii) below, but subject to Section 4.3.1.

(e) For purposes of calculating the Transmission Service Payment under the Formula Rate, (i) depreciation shall not be included before the Commercial Operation Date; (ii) AFUDC shall be accrued on all capital costs that were incurred during the Development Phase and Construction Phase and that are recoverable under the Formula Rate, such that recovery of a return on such capital costs, together with AFUDC accrued thereon, shall commence on the Commercial Operation Date (except as otherwise contemplated in Section 3.3 with respect to the recovery of costs and AFUDC following termination of this Agreement); and (iii) commencing on the date on which the Development Phase begins, Owner shall establish a regulatory asset that will include all Pre-COD Expenses, together with carrying charges on the regulatory asset at Owner's weighted cost of capital (as calculated under the Formula Rate) ("Carrying Charges") from the date on which the regulatory asset is established until the regulatory asset is fully amortized, and shall amortize such regulatory asset over a three (3)-year period commencing on the Commercial Operation Date.

(f) Owner shall seek FERC approval or acceptance to permit Owner to include in the regulatory asset described in clause (e)(iii) above all AC Upgrade Costs associated with the AC Upgrades placed-in-service before the Commercial Operation Date.

Section 8.1.3. Purchaser's Costs. Except as expressly contemplated by this Agreement for (a) any damages suffered by Purchaser as a result of an Owner Default, (b) any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement or to secure the release of any Purchaser Guaranty or other security or performance assurance provided by or on behalf of Purchaser after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of Purchaser to Owner hereunder shall have been fully, finally and indefeasibly satisfied, (c) fees and expenses reasonably incurred by Purchaser in enforcing Owner's participation obligation pursuant to Section 18.3.5 or (d) any indemnification obligations of Owner to Purchaser pursuant to Section 21.2, Owner shall have no liability to Purchaser or its Affiliates for any costs, expenses or charges incurred by Purchaser in connection with this Agreement.

Section 8.1.4. Challenges to Inclusion of Charges under the Formula Rate. Owner's right to recover any costs or expenses under the Formula Rate, and Purchaser's liability for such costs or expenses under this Agreement, shall be subject to the following provisions:

(a) The Formula Rate shall only include costs and expenses that were prudently incurred; provided that a rebuttable presumption shall exist that all costs and expenses included in the Formula Rate were prudently incurred, and nothing contained herein shall be construed to alter the burdens of proof and going forward, as set forth in clause (b) below.

(b) Subject to Section 18.2, Purchaser shall have the right to challenge the prudency of any costs or expenses that Owner seeks to recover from Purchaser under this Agreement by filing a pleading with FERC seeking to omit from the Transmission Service Payments calculated under the Formula Rate any costs or expenses included in the Formula Rate that were not prudently incurred. Such prudency challenge shall be made pursuant to Sections 306 and 309 of the Federal Power Act to invoke FERC's retained authority to investigate and order refunds with respect to any imprudent charges sought to be recovered under the Formula Rate. Any proceeding initiated by Purchaser to challenge the prudency of Owner's costs and expenses shall be conducted using the same standards and in accordance with the same procedures that FERC would normally apply to prudency challenges. Further, a rebuttable presumption shall exist that all costs and expenses included in the Formula Rate were prudently incurred; provided, however, that once Purchaser has met its initial burden to show that a cost or expense was not prudently incurred, the burden shall then shift back to Owner to prove that such cost or expense was prudently incurred. The Parties specifically intend and acknowledge and agree that, if FERC determines that any amount included in the Formula Rate was not prudently incurred, then such amount may be excluded from the Formula Rate effective as of the date such amount was first included in Owner's FERC account(s) that comprise the Formula Rate.

(c) Notwithstanding clauses (a) and (b) above, Purchaser acknowledges and agrees that no prudency challenge shall be permitted with respect to (i) any cost or expense to the extent approved by the Management Committee, including pursuant to Section 5.2.1(b), Section 5.2.2(b), Section 5.3(a), Section 6.3(b), Section 6.6(b), Section 9.3.2(b), Section 16.3(b) and Section 16.3(c), but excluding Section 5.2.3, Section 6.3(c) or

Section 6.4, or agreed to in writing by Purchaser or (ii) any cost or expense established pursuant to the arbitration provisions set forth in Section 18.3, other than any cost or expense so established as a result of an Impasse under Section 5.2.3, Section 6.3(c) or Section 6.4. Purchaser further acknowledges and agrees that its right to challenge any costs under this Section 8.1.4 shall be subject to Section 14.3(b).

(d) Subject to Section 5.5 and Section 6.3(b)(iii), in no event shall any (i) penalties assessed by FERC, NERC or any other Governmental Authority for any violation of Applicable Law by Owner, its Affiliates or any of its or their third-party contractors or (ii) payments made to settle allegations of such violations be recoverable under the Formula Rate, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, such amounts.

(e) This Section 8.1.4 shall not be construed in any way to limit any other rights Purchaser may have to file for relief with FERC pursuant to Section 18.2.

Section 8.1.5. Challenges to Application of Formula Rate. If, as a result of the audit of Owner's application of the Formula Rate or for any other reason, Purchaser believes that Owner has miscalculated or incorrectly included charges under the Formula Rate, Purchaser shall then have the right to submit the matter to the Management Committee for resolution under Section 18.1(a). If an Impasse occurs with respect to such matter, Purchaser shall then have the right to file a complaint with FERC seeking an order requiring Owner to comply with the Formula Rate, as its filed tariff.

Section 8.2. Service Life. For purposes of calculating the Transmission Service Payments under the Formula Rate, (a) the depreciable life of any depreciable asset comprising part of the Northern Pass Transmission Line as of the Commercial Operation Date shall be equal to forty (40) years, and (b) the depreciable life of a capital addition that is placed-in-service after the Commercial Operation Date shall be equal to the lesser of (i) its economic life and (ii) the remaining Term as of the placed-in-service date.

Section 8.3. Capital Structure.

(a) From and after the Development Phase, Owner shall use commercially reasonable efforts to maintain a Capital Structure equal to 50-50.

(b) Notwithstanding clause (a) above, at all times during the Term, the Capital Structure for purposes of calculating Transmission Service Payments under the Formula Rate shall be equal to 50-50.

Section 8.4. Return on Equity.

(a) The return on equity ("ROE") used in the Formula Rate to accrue AFUDC prior to the Commercial Operation Date and to calculate the weighted cost of capital for the Carrying Charges on the regulatory asset established pursuant to Section 8.1.2(e)(iii) shall be twelve and fifty-six one-hundredth percent (12.56%).

(b) Upon Commercial Operation, the ROE shall be adjusted to equal (i) the Base ROE, plus (ii) an adder equal to the lesser of (A) one hundred forty-two (142) basis points and (B) an amount that would not cause the total ROE to exceed the applicable zone of reasonableness for such Regional Transmission Service, as established in the most recent rate order for such service. In the event the Base ROE for Regional Transmission Service using the transmission facilities of Northeast Utilities is no longer based upon a single, regional Base ROE, Owner shall make a filing under Section 205 of the Federal Power Act to establish the ROE applicable to service under this Agreement that includes the adder set forth above; provided, however, that Owner shall delay such FERC filing for a period not less than thirty (30) days, but not to exceed sixty (60) days, to provide time for the Parties to negotiate the ROE to be applicable to service under this Agreement. The Parties acknowledge and agree that Purchaser shall have the right to challenge any FERC filing made under Section 205 of the Federal Power Act with respect to a replacement for the Base ROE, unless Purchaser shall have agreed in writing to the ROE set forth in such filing.

Section 8.5. Cost Recovery of AC Upgrades.

(a) The Parties acknowledge and agree that the AC Upgrades will be constructed and owned by the AC Upgrade Owners. Owner shall enter into a facilities agreement with each such AC Upgrade Owner to pay the costs to design, license, construct and operate such AC Upgrades (each, a "Facilities Agreement").

(b) Prior to executing any Facilities Agreement, Owner shall consult with the Management Committee with respect to the proposed terms and conditions thereof. The Management Committee shall promptly provide comments, if any, to Owner on such terms and conditions. Owner shall make a good faith effort to take into account any comments made by the Management Committee that are consistent with FERC rules and policies. Any Facilities Agreement entered into with an Affiliate of Northeast Utilities shall be on terms and conditions at least as favorable to Owner, when taken as a whole, as would have been obtained (at the time entered into) in a comparable arm’s-length transaction or arrangement with a Person other than an Affiliate of Northeast Utilities; provided, however, that, if such transaction or arrangement has been accepted or approved by FERC or any other Governmental Authority that specifically reviews the Affiliate relationship in such transaction or arrangement, then such transaction or arrangement shall be deemed to be a comparable arm’s-length transaction or arrangement.

(c) All amounts incurred by Owner under the Facilities Agreement ("AC Upgrade Costs") shall be recovered as expenses under the Formula Rate in accordance with Article 8. Notwithstanding the foregoing sentence, the AC Upgrade Costs under any Facilities Agreement entered into with an Affiliate of Northeast Utilities shall not exceed the costs and expenses that would have been incurred by Owner if the AC Upgrade Costs were directly incurred by Owner and recovered pursuant to the Formula Rate in accordance with this Agreement.

(d) Owner shall coordinate with the AC Upgrade Owners and ISO-NE as necessary to obtain for Purchaser the Other Transmission Rights under the ISO-NE Tariff that are associated with, or issued in connection with, the AC Upgrades, the costs of which AC Upgrades are incurred by Owner and recovered from Purchaser in accordance with this Agreement.

(e) In the event ISO-NE determines that all or any portion of the AC Upgrade Costs are eligible to be included in Regional Rates, Purchaser shall have the right, exercisable in its sole discretion, to continue to bear responsibility under this Agreement for all or any portion of the AC Upgrade Costs, in which case Purchaser shall continue to be entitled, in accordance with the ISO-NE Tariff, to all or any portion of the Other Transmission Rights that are associated with, or issued in connection with, Purchaser's continued responsibility for such AC Upgrade Costs.

Section 8.6. Transfer and Cost Recovery of AC Line.

(a) The AC Line shall be initially owned by Owner. AFUDC or Carrying Charges, as applicable, shall be accrued on the costs and expenses that are incurred by Owner in connection with the AC Line in accordance with Section 8.1.2(e)(ii) or Section 8.1.2(e)(iii), and, commencing on the Commercial Operation Date, such costs and expenses, together with AFUDC or Carrying Charges, as applicable, accrued thereon, shall be recoverable under the Formula Rate (i) in the same manner as the costs and expenses that are incurred by Owner in connection with the HVDC Line and (ii) otherwise in accordance with Article 8, except, in each case, as otherwise provided in clause (e) below.

(b) In the event all or any portion of the AC Line, for all or any part of the Term, meets the criteria for Pool Transmission Facilities ("PTF") (as those criteria and term are defined in the ISO-NE Tariff), Owner shall have the right, in its sole discretion, to transfer ownership of any such PTF portion of the AC Line to its Affiliate, PSNH, in accordance with this Section 8.6.

(c) In connection with any such transfer of ownership, Owner shall enter into an agreement with PSNH ("AC Line Agreement") pursuant to which Owner shall, subject to clause (e) below, (i) pay all costs and expenses (including unrecovered return on capital investment) that (A) have been or will be incurred in connection with such transferred portion of the AC Line, (B) have not been previously recovered under this Agreement, and (C) are not and will not be included in Regional Rates. To the extent not included in Regional Rates, such costs and expenses shall include those necessary for Purchaser's eligibility, in accordance with the ISO-NE Tariff, for the Other Transmission Rights that are associated with, or issued in connection with, the AC Line. Pursuant to the AC Line Agreement, Owner shall acquire sufficient rights with respect to such PTF portion of the AC Line to permit Owner to discharge its obligations under this clause (c) and Purchaser to exercise its rights under clause (f) below.

(d) Purchaser shall have the right to participate in the negotiation of the AC Line Agreement, and the Parties shall attempt to reach agreement on the rates, terms and conditions thereof, consistent with the parameters set forth in this Section 8.6. In the event the Parties fail to reach agreement with PSNH on the rates, terms and conditions of the AC Line Agreement within sixty (60) days following the commencement of such negotiations, Owner shall unilaterally file the AC Line Agreement with FERC in unexecuted form pursuant to Section 205 of the Federal Power Act, and Purchaser shall have the right to contest any of the rates, terms and conditions thereof, consistent with the parameters set forth in this Section 8.6, or to seek changes to the AC Line Agreement pursuant to Section 206 of the Federal Power Act, consistent with the parameters set forth in this Section 8.6. Except as provided in the foregoing sentence, and consistent with the terms of clause (b) above, Purchaser shall not have the right to oppose the transfer by Owner of ownership of any PTF portion of the AC Line to PSNH.

(e) All amounts incurred by Owner under the AC Line Agreement shall be recovered as expenses under the Formula Rate in accordance with Article 8. Notwithstanding the foregoing sentence, such amounts shall not exceed the costs and expenses that would have been incurred by Owner if the AC Line were still owned by Owner and such amounts were recovered pursuant to the Formula Rate in accordance with this Agreement. In no event shall Owner have the right to recover any return on investment associated with any PTF portion of the AC Line transferred to PSNH that is higher than the ROE established in Section 8.4.

(f) Upon a reasoned basis, Purchaser may request that Owner or PSNH, whichever is the owner of the AC Line (such party, "AC Line Owner"), determine and inform Purchaser of whether or not the costs and expenses associated with all or any portion of the AC Line should be included in Regional Rates. If AC Line Owner determines that such Regional Rate treatment is consistent with AC Line Owner's obligations and representations to FERC, other Governmental Authorities and AC Line Owner's Affiliates, then AC Line Owner shall submit such request to ISO-NE within ninety (90) days after the receipt by Owner of the request described in the first sentence of this clause (f). If ISO-NE subsequently determines that the costs and expenses associated with all or any portion of the AC Line are eligible to be included in Regional Rates, then Purchaser shall have the right, exercisable in its sole discretion, to take either of the following actions:

(i) Accept such Regional Rate treatment; or

(ii) Continue to bear responsibility under this Agreement for all or any portion of the costs and expenses associated with the transferred portion of the AC Line, in which case Purchaser shall be entitled, in accordance with the ISO-NE Tariff, to all or any portion of the Other Transmission Rights that are associated with, or issued in connection with, Purchaser's continued responsibility for such costs and expenses.

Owner and its Affiliates assume no obligations under this Agreement to advocate, with ISO-NE, NEPOOL or otherwise, for the Regional Rate treatment of all or any portion of the AC Line, and neither Owner nor its Affiliates shall have any liability to Purchaser if all or any portion of the AC Line does not receive such Regional Rate treatment. If AC Line Owner determines that it will not submit or support a request to ISO-NE for such Regional Rate treatment, then Owner shall notify Purchaser in writing of such decision within ninety (90) days after the receipt by Owner of the request described in the first sentence of this clause (f). Following the end of such ninety (90)-day period, Purchaser shall have the right to file a complaint with FERC seeking an order requiring such Regional Rate treatment.

(g) From and after the transfer to PSNH of those portions of the AC Line designated as PTF by ISO-NE, the following provisions shall apply for all purposes under this Agreement for the remainder of the Term:

(i) If the entirety of the AC Line has been designated PTF and transferred to PSNH, then the Delivery Point shall be the southern terminus of the HVDC Line at the DC/AC converter station located near the Webster substation in the City of Franklin in the State of New Hampshire, and if less than the entirety of the AC Line has been designated as PTF, then the Management Committee shall determine the appropriate Delivery Point;

(ii) References to the Northern Pass Transmission Line shall exclude all portions of the AC Line that have been designated as PTF;

(iii) References to the AC Upgrades, other than references thereto in Section 8.5, shall include the portions of the AC Line that have been designated as PTF;

(iv) Transmission service over the portions of the AC Line designated as PTF shall be provided in accordance with Section II of the ISO-NE Tariff and not pursuant to the terms and conditions of this Agreement; and

(v) Owner shall continue to maintain the Northern Pass Transmission Line to the same standard, in accordance with Section 6.2 and Section 6.3, as existed before the Delivery Point was changed.

ARTICLE 9

RIGHTS UPON EXPIRATION OF TERM

Section 9.1. Rollover Rights.

(a) Unless this Agreement is terminated early under Section 3.3, Section 15.3 or Section 15.4, Purchaser shall have rollover rights at the end of the initial Term in accordance with Order No. 890 *et seq.* and the FERC pro forma open access transmission service tariff, as such rights are defined as of the Effective Date.

(b) If Purchaser chooses to exercise rollover rights in accordance with clause (a) above, Owner shall then prepare and deliver to Purchaser, no later than six months after such exercise, an engineering assessment, which shall include an assessment of (i) the ability of the Northern Pass Transmission Line to operate for the proposed extended Term, (ii) any upgrades or refurbishment required to support the operation of the Northern Pass Transmission Line for the proposed extended Term, and (iii) forecasted capital expenditures over the proposed extended Term. All costs and expenses incurred by Owner in connection with such engineering assessment shall be recoverable under the Formula Rate in accordance with Article 8. If such engineering assessment indicates that the Northern Pass Transmission Line is incapable of providing Firm Transmission Service for the full duration of the extended Term requested by Purchaser or if the costs required to support the operation of the Northern Pass Transmission Line for the proposed extended Term are unacceptable to Purchaser, in its sole discretion, then Purchaser shall have the right, exercisable in its sole discretion, to (A) revise its election to reduce the period of the extended Term or (B) waive its rollover rights.

(c) Owner shall not enter into any contract or other arrangement for a Subsequent Use that is inconsistent with Purchaser's rollover rights, as provided herein.

Section 9.2. Reimbursement of Capital Costs. If, following the expiration or earlier termination of the Term, (a) a third party acquires service over the Northern Pass Transmission Line, or (b) the Northern Pass Transmission Line is included in Regional Rates (either event, a "Subsequent Use"), then Owner shall reimburse Purchaser for a pro rata portion of the costs and expenses associated with each capital addition comprising part of the Northern Pass Transmission Line that has an expected useful life beyond the end of the Term, as determined using the ratio of (i) the period of time during which such third party acquires service over the Northern Pass Transmission Line or, if ISO-NE includes the Northern Pass Transmission Line in Regional Rates, the remaining useful life of the Northern Pass Transmission Line following the end of the Term, and (ii) such period of time or remaining useful life, as applicable, plus the amortization period used to charge Purchaser for such capital addition. No later than thirty (30) days after Owner has entered into any contract or other arrangement for a Subsequent Use, Owner shall (A) calculate the reimbursement amount with respect to such contract or other arrangement, (B) provide a copy of such calculation to Purchaser, and (C) pay to Purchaser any amounts owed by Owner to Purchaser under this Section 9.2, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. Any Dispute with respect to the amount owed to Purchaser under this Section 9.2 shall be resolved in accordance with Article 18.

Section 9.3. Retirement and Decommissioning.

Section 9.3.1. Establishment of Regulatory Asset; Recovery of Net Decommissioning Costs.

(a) In the event all or a portion of the Northern Pass Transmission Line is required to be Decommissioned by Applicable Law, Owner shall establish the Regulatory Asset – Asset Retirement Obligation (Decommissioning), as defined in Attachment B. At the time Owner files this Agreement with FERC pursuant to Section 2.1(a), Owner shall also seek FERC approval or acceptance to permit Owner to establish such regulatory asset.

(b) Unless this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3 (in which case Section 9.3.3(c) shall apply) or under Section 3.3.7 or Section 15.4 (in which case Section 9.3.3(d) shall apply), promptly after the Decommissioning Plan is approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), Owner shall calculate the Levelized Monthly Decommissioning Payment. The "Levelized Monthly Decommissioning Payment" shall be equal to (i) the estimated Net Decommissioning Costs, as set forth in such Decommissioning Plan (which estimated Net Decommissioning Costs shall be expressed in dollars for the year(s) during which they are expected to be incurred and then discounted to the present value at the beginning of the first calendar day after the end of the Decommissioning Payment Period (regardless of whether or not such day is a Business Day) using a discount factor equal to the reasonably expected monthly rate of return applied in computing the Levelized Monthly Decommissioning Payment), multiplied by (ii) the Decommissioning Payment Formula. An example of this calculation is set forth in Attachment H. Thereafter, the Levelized Monthly Decommissioning Payment shall not be subject to change (unless such change shall have been agreed by the Parties or approved by the Management Committee).

(c) Owner shall have the right to make a unilateral filing under Section 205 of the Federal Power Act to establish a separate rate for the recovery of Net Decommissioning Costs consistent with this Section 9.3, rather than to recover such Net Decommissioning Costs under the Formula Rate, and Purchaser shall have the right to challenge such filing, unless Purchaser shall have agreed in writing on such filing.

Section 9.3.2. Decommissioning Plan.

(a) No later than six (6) months before the commencement of the Decommissioning Payment Period, or if this Agreement is earlier terminated under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, no later than sixty (60) days after such termination, Owner shall deliver to the Management Committee a statement that sets forth in reasonable detail (i) Owner's estimation of (A) the Decommissioning Costs and Salvage Proceeds and, unless this Agreement is terminated early under Section 3.3 or Section 15.3, the Levelized Monthly Decommissioning Payment derived therefrom, and (B) any activities associated with either thereof and (ii) the scope and frequency of informational progress reports with respect to the Decommissioning of the Northern Pass Transmission Line, including the process for the recovery by Owner of its actual Net Decommissioning Costs following the exhaustion of the Decommissioning Fund prior to the completion of Decommissioning (collectively, the "Decommissioning Plan"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Decommissioning Plan.

(b) The Management Committee shall attempt to agree upon the Decommissioning Plan within sixty (60) days following its receipt thereof, and the Management Committee may approve the proposed Decommissioning Plan in whole or in part. If an Impasse occurs with respect to the proposed Decommissioning Plan (or any part thereof), then the matter shall be resolved pursuant to the arbitration provisions set forth in Section 18.3.

(c) Owner shall use commercially reasonable efforts not to exceed the estimated amounts set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto); provided, however, that all Net Decommissioning Costs actually incurred by Owner, whether or not set forth in such Decommissioning Plan, shall be recoverable under this Agreement in accordance with this Section 9.3, subject to (i) reallocation upon a Subsequent Use, if any, as described in Section 9.3.4, and (ii) challenge on prudence grounds, if applicable, as described in Section 9.3.6.

Section 9.3.3. Payment of Decommissioning Costs.

(a) Unless this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3 (in which case clause (c) below shall apply) or under Section 3.3.7 or Section 15.4 (in which case clause (d) below shall apply), Owner shall include the Levelized Monthly Decommissioning Payment in the Formula Rate during each of the last sixty (60) months of the Term (excluding any extension of the Term made after the thirty-fifth (35th) anniversary of the Commercial Operation Date pursuant to Section 9.1 or Section 16.4) (the "Decommissioning Payment Period"). If the Management Committee shall not have approved the Decommissioning Plan (or the Decommissioning Plan shall not have been determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) prior to the commencement of the Decommissioning Payment Period, then the following provisions shall apply, notwithstanding anything herein to the contrary:

(i) The Levelized Monthly Decommissioning Payment included in the Formula Rate pursuant to this clause (a) shall be equal to (A) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan delivered to the Management Committee under Section 9.3.2(a), multiplied by (B) the Decommissioning Payment Formula (each such monthly payment amount, the "Preliminary Monthly Decommissioning Payment").

(ii) Promptly after the Decommissioning Plan has been approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), but in no event later than thirty (30) days thereafter, Owner shall complete the following tasks: (A) calculate the Levelized Monthly Decommissioning Payment in accordance with Section 9.3.1(b); (B) retroactively adjust all payments previously made by Purchaser with respect to the Decommissioning Payment Period to reflect the Levelized Monthly Decommissioning Payment rather than the Preliminary Monthly Decommissioning Payment and (C) thereafter conform all future Invoices to reflect such Levelized Monthly Decommissioning Payments.

(iii) If and to the extent the aggregate Levelized Monthly Decommissioning Payments owed by Purchaser for the period prior to the date on which Owner shall have completed the tasks described in clause (a)(ii) above is less than the aggregate Preliminary Monthly Decommissioning Payments made by Purchaser for such period, then, within thirty (30) days after the calculation of the Levelized Monthly Decommissioning Payment contemplated by clause (a)(ii) above, Owner shall withdraw from the Decommissioning Fund and refund to Purchaser such overpayment in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the aggregate Levelized Monthly Decommissioning Payments owed by Purchaser for the period prior to the date on which Owner shall have completed the tasks described in clause (a)(ii) above is greater than the aggregate Preliminary Monthly Decommissioning Payments made by Purchaser for such period, then, within thirty (30) days after a written demand therefor from Owner, Purchaser shall deposit into the Decommissioning Fund such deficiency in immediately available funds in accordance with the terms and conditions established by the Management Committee, as contemplated by clause (b) below. Notwithstanding anything herein to the contrary, the withdrawal of any overpayment or the deposit of any deficiency, in each case, contemplated by this clause (a)(iii) shall not be subject to the provisions of Section 14.5.

(b) All Levelized Monthly Decommissioning Payments and Preliminary Monthly Decommissioning Payments, as applicable, included in the Formula Rate pursuant to clause (a) above and the Decommissioning Estimate described in clause (c) below, that are, in each case, paid by Purchaser shall be deposited into an external fund created on terms and conditions established by the Management Committee to protect the interests of each Party and to ensure that such fund is used for the purposes contemplated by this Agreement (the "Decommissioning Fund"), until applied to the Net Decommissioning Costs in accordance with Section 9.3.5(c) or refunded to Purchaser under Section 9.3.5(e).

(c) If this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, then Purchaser shall deposit into the Decommissioning Fund, an amount equal to (i) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) (which estimated Net Decommissioning Costs, solely for the purpose of calculating the Decommissioning Estimate, shall be expressed in dollars as of the date on which this Agreement is terminated as if the Decommissioning were to commence as of such date), less (ii) the balance, if any, in the Decommissioning Fund as of the date such payment is due (the "Decommissioning Estimate"). Purchaser shall make such payment within thirty (30) days following the later to occur of (A) the receipt by Purchaser of the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) and (B) the date on which the estimated Net Decommissioning Costs have been redetermined, as provided in the immediately ensuing sentence (the "Decommissioning Payment Date"). If this Agreement is terminated prior to the expiration of the Term pursuant to Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, but after the Decommissioning Plan has been approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), then the Parties shall agree upon modifications to the estimated Net Decommissioning Costs, as set forth in such Decommissioning Plan, consistent with the first sentence of this clause (c). Any Dispute with respect to such redetermination shall be resolved pursuant to the arbitration provisions set forth in Section 18.3.

(d) If this Agreement is terminated prior to the expiration of the Term pursuant to Section 3.3.7 or Section 15.4, then Purchaser shall have no liability for any Decommissioning Costs, and Owner shall refund to Purchaser all amounts remaining in the Decommissioning Fund no later than sixty (60) days after such termination.

(e) If Hydro-Québec pays to Owner the Decommissioning Liquidated Damages, as provided in the Purchaser Guaranty, then such payment shall satisfy, in full, the obligations of Purchaser to pay Decommissioning Costs and Purchaser shall cease to have (i) any further obligation to pay any Decommissioning Costs hereunder, including under Section 9.3.5(d), (ii) any right to any reimbursement, refund or reduction if the actual Net Decommissioning Costs are less than the Decommissioning Liquidated Damages, including under Section 9.3.5(e) and (iii) any right to challenge the prudency of the Net Decommissioning Costs or the Decommissioning Estimate under Section 9.3.6 or otherwise.

Section 9.3.4. Subsequent Use. In the event Owner (a) receives an offer for a Subsequent Use for service to commence immediately following the expiration or earlier termination of the Term or at any time thereafter until the Northern Pass Transmission Line has been fully Decommissioned and (b) desires to accept such offer or otherwise enter into another arrangement for a Subsequent Use, Owner shall notify Purchaser in writing of the material terms and conditions of such proposed Subsequent Use and Owner and Purchaser shall negotiate in good faith with such proposed third-party transmission customer or ISO-NE, as applicable, to determine the allocation of Net Decommissioning Costs between Purchaser and such proposed third-party transmission customer or ISO-NE, as applicable. Any Net Decommissioning Costs allocated to Purchaser shall be fixed by reference to the budgeted amounts for Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), and shall not be subject to any payments or refunds pursuant to Section 9.3.5(d) or Section 9.3.5(e) with respect to Decommissioning Costs actually incurred by Owner or Salvage Proceeds actually received by Owner in connection with the Decommissioning of the Northern Pass Transmission Line. If the Parties and the proposed third-party transmission customer or ISO-NE, as applicable, fail to reach agreement on the allocation of Net Decommissioning Costs between Purchaser and such proposed third-party transmission customer or ISO-NE, as applicable, within sixty (60) days after the receipt by Purchaser of the notice described in the first sentence of this Section 9.3.4, then Owner shall make a unilateral filing under Section 205 of the Federal Power Act to establish such allocation of Net Decommissioning Costs, consistent with this Section 9.3.4, and Purchaser shall have the right to challenge such filing. If Owner enters into a contract or other arrangement for such Subsequent Use, then Owner shall deliver to Purchaser a statement setting forth in reasonable detail the amount equal to (i) the Net Decommissioning Costs, less (ii) the sum of (A) the reallocated portion of the Net Decommissioning Costs and (B) the balance, if any, in the Decommissioning Fund as of the date such statement is due (the "Purchaser's Decommissioning Balance"), within thirty (30) days after the later to occur of (1) the date on which this Agreement has expired or otherwise terminated, (2) the date on which Owner has entered into such contract or other arrangement for such Subsequent Use or (3) provided Owner has made a unilateral filing with FERC to establish the allocation of Net Decommissioning Costs, the date on which FERC has issued an order establishing the allocation of Net Decommissioning Costs. If and to the extent the Purchaser's Decommissioning Balance is less than zero (0), then, concurrently with the delivery of such statement, Owner shall refund to Purchaser the absolute value of the Purchaser's Decommissioning Balance, in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the Purchaser's Decommissioning Balance is greater than zero (0), then Purchaser shall pay the Purchaser's Decommissioning Balance to Owner, in a single lump sum due thirty (30) days following the receipt by Purchaser of such statement, but otherwise in a manner consistent with Section 14.1. Either Party may deduct and setoff payment of such

Purchaser's Decommissioning Balance against any accrued but unpaid payment obligation of the other Party to such Party hereunder.

Section 9.3.5. Decommissioning Process. The following provisions shall apply to the Decommissioning of the Northern Pass Transmission Line unless a Subsequent Use has occurred:

(a) Owner shall complete the Decommissioning of the Northern Pass Transmission Line in accordance with the Decommissioning Plan, unless otherwise required by Applicable Law.

(b) In connection with the Decommissioning of the Northern Pass Transmission Line, Owner shall (i) use commercially reasonable efforts to sell the Project Assets (other than the Project Assets acquired by Purchaser pursuant to Section 3.5(a)(iii)) at their fair market value to one or more third parties (which may include Affiliates of Owner) and (ii) credit the proceeds of such sale, net of reasonable fees (including attorneys' fees) and other expenses (including storage costs) incurred by Owner in connection with such sale (the "Salvage Proceeds") against the Decommissioning Costs, and to the extent the Salvage Proceeds exceed the Decommissioning Costs, against other amounts owed to Owner by Purchaser under this Agreement. For the avoidance of doubt, no Project Asset acquired by Purchaser pursuant to Section 3.5(a)(iii) shall generate any Salvage Proceeds.

(c) Owner shall draw upon the Decommissioning Fund on a monthly basis for its actual Net Decommissioning Costs. The Decommissioning Fund shall be administered in all other respects consistent with the terms and conditions established by the Management Committee for the Decommissioning Fund.

(d) In the event Owner's draws upon the Decommissioning Fund for its actual Net Decommissioning Costs shall have exhausted the Decommissioning Fund prior to the completion of Decommissioning, Owner shall thereafter invoice Purchaser on a monthly basis (unless another interval shall have been agreed by the Parties or approved by the Management Committee) for Owner's actual Net Decommissioning Costs thereafter incurred until the Decommissioning has been completed. Owner shall submit such invoices to Purchaser (in reasonable detail to evidence the basis for individual billings and charges), and Purchaser shall pay the amounts set forth in such invoices, in each case, in a manner consistent with Section 14.1 (unless another manner shall have been agreed by the Parties or approved by the Management Committee). Purchaser's payment of any amounts set forth in such invoices (i) shall not be deemed to be an acceptance or approval by Purchaser of the correctness or prudency of the costs reflected therein (provided that nothing herein shall alter the otherwise applicable burden of proof set forth in Section 8.1.4 for prudency challenges or time limit set forth in Section 14.3(b), as modified by Section 9.3.6, within which Purchaser has the right to challenge an invoice) and (ii) shall be without prejudice to any right or remedy that Purchaser may have under this Agreement, including under Section 9.3.6, to contest any such amount. Purchaser may deduct and setoff payment of such amounts against any accrued but unpaid payment obligations of Owner to Purchaser hereunder.

(e) If and to the extent Owner's draws upon the Decommissioning Fund shall not have exhausted the Decommissioning Fund upon the completion of Decommissioning, then, within thirty (30) days following the completion of the Decommissioning, Owner shall refund to Purchaser, in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing, the remaining balance in the Decommissioning Fund as of the date such payment is due. Owner may deduct and setoff payment of such refund against any accrued but unpaid payment obligations of Purchaser to Owner hereunder.

Section 9.3.6. Prudency Challenges. Unless a Subsequent Use has occurred and subject to Section 9.3.3(e), Decommissioning Costs actually incurred by Owner and invoiced to Purchaser as provided in this Section 9.3, and Salvage Proceeds actually received by Owner and credited against the Decommissioning Costs or against other amounts owed to Owner by Purchaser under this Agreement, as provided in this Section 9.3, are subject to Purchaser's right to challenge the prudency of such Decommissioning Costs or Salvage Proceeds before FERC to the extent such Decommissioning Costs are higher than, or such Salvage Proceeds are lower than, the budgeted amounts therefor, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), which prudency challenge shall be subject, *mutatis mutandis*, to the procedures and standards set forth in Section 8.1.4. For purposes of applying the provisions of Section 14.3 to such prudency challenges, all invoices rendered pursuant to Section 9.3.5(d) shall be deemed to have been rendered on the date the last such invoice shall have been rendered.

Section 9.3.7. Limitations on the Parties' Decommissioning Rights and Obligations. The following provisions shall apply, notwithstanding anything herein to the contrary:

(a) Subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.2, the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

(b) If Owner shall have failed to comply with the provisions of Section 5.1.2(a)(ii)(A), then, subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.3, the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

(c) If Owner shall have failed to comply with the provisions of Section 5.1.2(a)(ii), then, subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.5(a), the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

ARTICLE 10

RESALE OF TRANSMISSION SERVICE

Section 10.1. Resale Rights of Purchaser. If and to the extent Purchaser determines from time to time, and in its sole discretion, that the transmission capacity available over the Northern Pass Transmission Line exceeds Purchaser's needs, Purchaser shall then offer to resell such unused capacity to third parties in accordance with Applicable Law as may then be in effect (including the terms and conditions of FERC Order No. 890 *et seq.*, if applicable).

Section 10.2. Capacity Releases for Daily and Hourly Use. From and after the Commercial Operation Date, if and to the extent the Total Transfer Capability of the Northern Pass Transmission Line exceeds the amount of electrical energy that Purchaser has scheduled for delivery over the Northern Pass Transmission Line by the applicable scheduling deadline (as in effect at such time) established pursuant to the Scheduling Rules, then the transmission capacity that is available for resale to third parties for the following day, and the price at which any such resales are offered, shall be posted on the OASIS site established pursuant to Section 10.3.

Section 10.3. OASIS.

(a) The Parties shall jointly contract with an independent, non-affiliated third party (the "OASIS Provider") for use of an OASIS site. The OASIS Provider shall post the transmission capacity available for resale over the Northern Pass Transmission Line and schedule related transmission service over the Northern Pass Transmission Line on such OASIS site in accordance with written instructions that Purchaser or the OASIS Administrator, as applicable, may provide to the OASIS Provider from time to time. In connection with any such posting, the Parties shall comply with FERC Order No. 890 *et seq.* at all times and shall direct the OASIS Provider to comply with same.

(b) To the extent resales are made available by Purchaser pursuant to Section 10.1, the OASIS Provider shall post on the OASIS site information regarding such resales, (i) in accordance with written instructions provided by Purchaser from time to time and (ii) at a price established by Purchaser from time to time, and in its sole discretion, as permitted under Applicable Law.

(c) The Parties shall jointly contract with an independent, non-affiliated third party (the "OASIS Administrator"), which entity may be the same as or different from the OASIS Provider, to carry out the capacity release functions for daily and hourly resales set forth in Section 10.2 in a commercially reasonable manner and in compliance with applicable FERC rules and regulations.

(i) In addition to assigning the responsibility for such capacity release functions, such contract shall also contain the following provisions, at a minimum, unless waived by the Management Committee, (A) to the extent neither Party voluntarily assumes the responsibility to perform Necessary Administrative Functions, the OASIS Administrator shall be required to perform such functions, (B) the OASIS Administrator shall be required to use commercially reasonable efforts to collect amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Article 10 and (C) the Parties shall have the right to terminate the contract, with or without cause, within a reasonable timeframe and without damages. The term "Necessary Administrative Functions" as used herein includes the following functions: entering into transmission service agreements with third-party assignees; billing and collecting transmission service payments from third-party assignees; crediting the proceeds of any capacity releases and transmission resales to Purchaser; making all required regulatory filings (such as Electronic Quarterly Reports) with FERC; and performing any other administrative functions relating to capacity releases, transmission resales or the scheduling of transmission service. Any Dispute with respect to the selection of an OASIS Administrator or the terms and conditions of a contract to employ an OASIS Administrator shall be resolved pursuant to the arbitration provisions set forth in Section 18.3, but any such resolution shall be consistent with the terms of this clause (c)(i). Following resolution of any such Dispute, the Parties will take such actions as are reasonably necessary to contract with the OASIS Administrator on the terms and conditions consistent with the resolution of such Dispute.

(ii) Each Party shall designate a representative, and the two representatives so designated shall jointly be assigned the responsibility to (A) monitor the OASIS Administrator's activities, (B) administer the contract entered into by the Parties with the OASIS Administrator, and (C) provide periodic reports to the Management Committee, as requested by any Manager, with respect to the performance of the OASIS Administrator.

(iii) The costs incurred pursuant to the contract with the OASIS Administrator shall be recovered under the Formula Rate in accordance with Article 8; provided that Purchaser shall not have the right under Section 8.1.4 to challenge costs incurred by Owner under a contract with the OASIS Administrator to which Purchaser is a party. Further, Purchaser shall not have the right under Section 8.1.4 to challenge the prudency of revenues received from resales or reassignments of transmission capacity to third parties made by the OASIS Administrator pursuant to clause (c)(i) above and credited to Purchaser under the Formula Rate in accordance with Article 8.

(iv) If either Party believes that the OASIS Administrator is acting in a manner adverse to its interests, such Party shall then have the right to submit the matter to the Management Committee for resolution. Any Impasse with respect to such matter shall be resolved pursuant to the arbitration provisions set forth in Section 18.3. Following resolution of any such Dispute, the Parties will take such actions as are reasonably necessary to implement the resolution of such Dispute.

(v) Nothing contained herein shall be construed as preventing a Party from enforcing the terms and conditions of any contract with an OASIS Administrator, including the recovery of damages against the OASIS Administrator for breach, non-performance, negligence or other misfeasance in performing the Necessary Administrative Functions or its other duties thereunder; provided, however, that damages received from the OASIS Administrator by Owner, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts, shall be credited to the Formula Rate pursuant to Article 8 to the extent such damages relate to costs paid or payable by Purchaser under the Formula Rate or revenue credits for the services of the OASIS Administrator.

Section 10.4. Proceeds from Capacity Releases and Transmission Resales. Except as otherwise provided in Section 15.3(b), the proceeds received by Owner of any capacity releases and transmission resales made pursuant to this Article 10 shall be credited, net of reasonable fees (including attorneys' fees) and other expenses incurred in connection with performance of the functions described in Section 10.2 and Section 10.3, against any Transmission Service Payment or other amounts owed to Owner by Purchaser for the calendar month subsequent to the calendar month in which such proceeds were received. Owner shall have no liability for, or obligation to credit to Purchaser under the Formula Rate, amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Article 10.

Section 10.5. Owner's Rights and Obligations. Except as expressly provided in this Agreement, Owner shall have no right or obligation to offer any transmission service over the Northern Pass Transmission Line for sale or resale to any Person other than Purchaser.

ARTICLE 11

REAL POWER LOSSES, CONGESTION AND CAPACITY RIGHTS

Section 11.1. Real Power Losses. Purchaser shall be responsible for all Real Power Losses associated with Firm Transmission Service and Additional Transmission Service between the U.S. Border and the Delivery Point; provided, however, that, if and to the extent any Real Power Losses associated with Firm Transmission Service and Additional Transmission Service between the U.S. Border and the Delivery Point are due to Owner's failure to exercise Good Utility Practice or otherwise discharge its obligations under this Agreement, such incremental Real Power Losses shall be treated as Non-Excused Outages for which Owner shall be liable in accordance with Section 7.4, and the rights and remedies contemplated by Section 7.4, including the rights provided in Section 3.3.12, shall collectively be the sole and exclusive remedy of Purchaser with respect to any such incremental Real Power Losses as provided in Section 7.4.4. The assignment of losses associated with the transmission of electric power over the AC Upgrades shall be determined in accordance with the ISO-NE Rules.

Section 11.2. Other Rights.

(a) Purchaser shall be entitled to the following, without duplication and without additional cost to Purchaser or compensation to Owner, (i) all Other Transmission Rights associated with the Northern Pass Transmission Line or, to the extent the costs of which are incurred by Owner and recovered from Purchaser under this Agreement, the AC Upgrades, in each case, that are issued in accordance with the ISO-NE Tariff or otherwise granted under the ISO-NE Rules, or otherwise created or awarded by ISO-NE, and (ii) all other Market Products that are issued in accordance with the ISO-NE Tariff or granted under the ISO-NE Rules, or otherwise created or awarded by ISO-NE, that derive from the acquisition of transmission service over the Northern Pass Transmission Line. As Owner's sole obligation under this clause (a), upon its receipt of any of the entitlements or rights described in the foregoing sentence, Owner shall promptly convey such entitlements or rights to Purchaser.

(b) In the event tie benefits or interconnection capability credits (or any similar concept) are ever deemed applicable to the Northern Pass Transmission Line and to the extent allocated to either Party, Purchaser shall be entitled to one hundred percent (100%) of the economic benefits associated therewith (however entitled and whether existing now or in the future), without additional cost to Purchaser or compensation to Owner.

(c) Owner shall have no obligation to support the creation or establishment of any of the rights described in clauses (a)(ii) and (b) above, but Owner may not oppose the creation or establishment of any such right, unless otherwise agreed in writing by Purchaser. Neither Section 2.4 nor the foregoing sentence shall be construed in any way to limit the right of any Affiliate of Owner to oppose the creation or establishment of any of the rights described in clauses (a)(ii) and (b) above.

ARTICLE 12

ANCILLARY SERVICES

Section 12.1. Responsibility for Ancillary Services. Purchaser shall be responsible for any Ancillary Services that are required under the ISO-NE Tariff in connection with the transmission of electric power over the Northern Pass Transmission Line. Responsibility for ancillary services that are required under the ISO-NE Tariff in connection with the transmission of electric power over the AC Upgrades shall be determined in accordance with the ISO-NE Rules.

Section 12.2. Revenues from Ancillary Services. All revenues received by Owner in respect of any ancillary services (however defined) associated with the Northern Pass Transmission Line (other than revenues received in respect of ancillary services associated with transmission service scheduled for a third-party customer) and, to the extent applicable, the AC Upgrades shall be credited, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner with respect to the provision of such ancillary services, against any amounts owed to Owner by Purchaser for the calendar month subsequent to the calendar month in which such revenues were received by Owner.

ARTICLE 13

MANAGEMENT COMMITTEE

Section 13.1. Management Committee. No later than ten (10) days after the Execution Date, the Parties shall establish a committee ("Management Committee") by appointment of the Managers, which committee shall (a) coordinate and oversee the implementation and administration of this Agreement, including matters relating to the Parties' performance obligations under this Agreement, but excluding decisions that may be made by either or both of the Parties under the express terms and conditions of this Agreement, (b) bear responsibility for the matters expressly under the purview of the Management Committee pursuant to the terms and conditions of this Agreement, and (c) handle any other matters delegated to the Management Committee by the express written agreement of the Parties. The ensuing provisions of this Article 13 shall apply to the Management Committee.

Section 13.2. Appointment and Authority of Managers.

(a) Owner and Purchaser shall each be entitled to appoint one member to serve on the Management Committee as a voting member (each a "Manager"). In addition, Owner and Purchaser shall each designate, within ten (10) days after the Execution Date, an alternate to its Manager (each, an "Alternate Manager") with the authority to serve in place of, and with the authority of, such Manager solely if such Manager is absent from, or unavailable to attend, a Management Committee meeting. Owner and Purchaser may also each appoint such other non-voting members of the Management Committee as such Party deems advisable to perform the tasks assigned to the Management Committee, and may remove or replace such non-voting members, in each case, in its sole discretion. Each Party shall promptly give written notice to the other Party of any change in the business address or business telephone of its Manager or Alternate Manager (collectively, its "Authorized Representatives").

(b) Each Authorized Representative shall be an agent of the Party that designated such Authorized Representative, and subject to Section 13.1 and the next two sentences, each Authorized Representative shall have the right and authority to bind the Party such Authorized Representative represents. In respect of the Authorized Representatives, (i) each Authorized Representative shall have power to act (or refrain from acting) solely in accordance with the wishes of the Party that designated such Authorized Representative, (ii) the acts of an Authorized Representative with respect to any matter shall be deemed to be the acts of the Party that designated such Authorized Representative, and (iii) no Authorized Representative shall owe (or be deemed to owe) any duty (fiduciary or otherwise) to any Party other than the Party that designated such Authorized Representative. Notwithstanding the foregoing, no Authorized Representative, in such capacity, shall have the authority to (A) amend, waive, revise, modify or terminate this Agreement or any portion thereof, (B) serve any notice alleging breach of this Agreement, or (C) enter into, settle or otherwise dismiss any FERC or arbitration proceeding under Section 18.2 or Section 18.3.

(c) The compensation and expenses of Owner's Authorized Representatives, including an allocated share of overhead, shall be recoverable under the Formula Rate in accordance with Article 8.

Section 13.3. Term of Managers; Resignation, Removal and Vacancies. Each Authorized Representative shall serve until the earlier to occur of such Authorized Representative's resignation or removal. An Authorized Representative may resign as such at any time by delivering written notice to that effect to Owner and Purchaser, and the effective date of such resignation shall be the date upon which such notice is delivered, unless another date therefor is specified therein. An Authorized Representative may be removed or replaced at any time and for any reason and without the approval of the other Party by the Party that appointed such Authorized Representative. In the event a vacancy on the Management Committee occurs as a result of the death, disability, resignation, removal or otherwise of a

Manager, such vacancy shall be promptly filled by the Party that appointed the vacating Manager. Such Party shall provide written notice to the other Party whenever an Authorized Representative appointed by such Party is removed or replaced.

Section 13.4. Meetings; Attendance.

(a) Meetings of the Management Committee shall be held on a monthly basis prior to the Commercial Operation Date and quarterly thereafter, or more frequently as determined by the Parties or the Management Committee, on such dates and at such times as may be determined by the Management Committee. Notwithstanding the foregoing sentence, a Party may call a special meeting by reasonable advance notice to the other Party's Manager in writing.

(b) Each Party shall use reasonable efforts to cause its Manager or Alternate Manager to attend each Management Committee meeting, and no Party shall withhold the presence or participation of its Manager or Alternate Manager to prevent, delay or forestall decisions on matters under consideration by the Management Committee. The Parties shall cause their respective Authorized Representatives not to delay unreasonably any actions of the Management Committee.

(c) All meetings of the Management Committee shall be held at Owner's principal place of business or at such other place (or means if by telephone conference or other means) as shall be agreed upon by the Parties or the Management Committee. A designee of the Management Committee shall provide written notice to each Party and Manager stating the date and hour of each Management Committee meeting, together with a detailed agenda for the meeting, not less than five (5) Business Days before such meeting. Attendance of an Authorized Representative of a Party at a Management Committee meeting shall constitute a waiver of the foregoing notification requirement by such Party.

(d) A designee of the Management Committee shall record minutes of each meeting and, within seven (7) Business Days following such meeting, shall provide to each Party and Manager a copy of such minutes. If applicable, such minutes shall be in such detail as required for purposes of Section 6.7.

Section 13.5. Rules. The Management Committee may adopt such rules of order as it considers necessary or appropriate for the conduct of its business and the exercise of its powers, none of which shall conflict with this Agreement.

Section 13.6. Action by the Management Committee. An Authorized Representative of Owner and an Authorized Representative of Purchaser shall together constitute a quorum for the transaction of business, and each Authorized Representative shall have one (1) vote on all decisions of the Management Committee. The affirmative vote of an Authorized Representative of Owner and an Authorized Representative of Purchaser shall be the act of the Management Committee.

Section 13.7. Action by Written Consent. Any action that may be taken by the Management Committee under this Agreement may be taken without a meeting and without a vote if there is written consent, setting forth the action so taken, and signed by an Authorized

Representative of Owner and an Authorized Representative of Purchaser or with the electronic approval of an Authorized Representative of Owner and an Authorized Representative of Purchaser. Any action taken by the written consent shall have the same force and effect as if taken at a meeting. If applicable, such written consent shall be in such detail as required for purposes of Section 6.7.

Section 13.8. Telephonic Meetings. Managers may participate in any meeting of the Management Committee by means of conference telephone or similar communication equipment by which both Managers participating in the meeting can hear each other at the same time. Such participation shall constitute presence in person at the meeting.

Section 13.9. Impasse between the Managers. Except in the case of any Annual Plan and Operating Budget, an "Impasse" shall be deemed to have occurred if, for any reason, the Authorized Representatives are unable to reach agreement on a matter submitted to the Management Committee for approval or any Dispute referred to the Management Committee for resolution within thirty (30) days after such submission or referral, or such earlier or longer period as the Management Committee may establish. In the case of any Annual Plan and Operating Budget, an "Impasse" shall be deemed to have occurred if, for any reason, the Authorized Representatives are unable to reach agreement on an Annual Plan and Operating Budget submitted to the Management Committee within sixty (60) days after such submission, or such earlier or longer period as the Management Committee may establish.

ARTICLE 14

BILLING AND PAYMENTS

Section 14.1. Invoices.

(a) No later than sixty (60) days before the date Owner reasonably expects the Commercial Operation Date to occur, Owner shall deliver to Purchaser an estimated Revenue Requirement for the first Contract Year, pursuant to which the Transmission Service Payments shall be calculated under the Formula Rate, such estimated Revenue Requirement to be effective as of the Commercial Operation Date.

(b) The monthly Transmission Service Payments shall be calculated as follows:

(i) The monthly Transmission Service Payments for the first Contract Year shall be calculated by dividing (A) the estimated Revenue Requirement described in clause (a) above, by (B) the number of calendar months in such Contract Year.

(ii) The monthly Transmission Service Payments for any Contract Year thereafter, other than the final Contract Year, shall be calculated by dividing (A) the estimated Revenue Requirement for such Contract Year by (B) twelve (12).

(iii) The monthly Transmission Service Payments for the final Contract Year shall be calculated by dividing (A) the estimated Revenue Requirement for such final Contract Year by (B) number of calendar months in such Contract Year.

(c) Within seven (7) Business Days after the first day of each calendar month following the commencement of the Operation Phase, Owner shall submit an Invoice to Purchaser for the Transmission Service Payments owed for the preceding calendar month, and Purchaser shall pay the amounts set forth in the Invoice within fourteen (14) Business Days following its receipt of such Invoice. During the Decommissioning Payment Period, all Invoices shall separately set forth the portion of the Transmission Service Payment that is associated with the Levelized Monthly Decommissioning Payment or Preliminary Monthly Decommissioning Payment, as applicable. All payments shall be made in immediately available funds payable to Owner by wire transfer to a bank named by Owner, in accordance with wiring instructions provided to Purchaser by Owner in writing, except that the Levelized Monthly Decommissioning Payment or Preliminary Monthly Decommissioning Payment, as applicable, shall be made in immediately available funds and deposited into the Decommissioning Fund in accordance with the terms and conditions established by the Management Committee, as contemplated by Section 9.3.3(b). Owner shall be entitled to change the place or recipient for payment by thirty (30) days' prior written notice to Purchaser.

(d) Invoices provided under this Agreement will be based upon the estimated Revenue Requirement, subject to a true-up to actual costs pursuant to Section 14.2. For the first Contract Year, the estimated Revenue Requirement described in clause (a) above shall become effective as of the Commercial Operation Date. For each Contract Year thereafter, the estimated Revenue Requirement for such Contract Year, shall become effective on January 1st of such Contract Year.

Section 14.2. Reconciliation; Audit Rights.

(a) Owner shall provide Purchaser with a statement setting forth in reasonable detail all of the costs and expenses used to calculate the trued-up annual Revenue Requirement pursuant to the Formula Rate during the prior year, and the activities associated therewith, no later than sixty (60) days after Owner has filed its FERC Form 1 for such prior year. The foregoing statement shall detail all components of the amounts included in the Formula Rate and all calculations used to determine the final Transmission Service Payments thereunder (based upon costs actually incurred).

(b) At Purchaser's reasonable request, Owner shall make available to Purchaser any information reasonably necessary to permit Purchaser to audit Owner's application of the Formula Rate. At Purchaser's reasonable request, Owner shall also make available to Purchaser any information reasonably necessary to support the borrowing cost of any Additional Financing described in clause (a)(i) of the definition thereof. Owner acknowledges and agrees that the making of any payment hereunder by Purchaser or the approval of any cost estimate, budget, schedule or maintenance plan by the Management Committee shall be without prejudice to the audit rights of Purchaser provided herein.

(c) If and to the extent the total amount of the estimated Transmission Service Payments initially paid by Purchaser for any calendar year is greater than the costs actually incurred in such calendar year under the Formula Rate, then Owner shall refund to Purchaser the excess amounts collected, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum due on the same date on which Owner is required to submit the first Invoice to be delivered after the receipt by Purchaser of the statement described in clause (a) above. If and to the extent the total amount of the estimated Transmission Service Payments initially paid by Purchaser for any calendar year is less than the costs actually incurred during such calendar year under the Formula Rate, then Purchaser shall pay a surcharge to Owner in the amount of such deficiency, together with interest thereon calculated pursuant to Section 14.5(b), which surcharge shall be payable in a single lump sum due on the same date on which Purchaser is required to pay the amounts set forth in the first Invoice to be delivered after the receipt by Purchaser of the statement described in clause (a) above. Solely for purposes of performing the calculations set forth in this clause (c), for any calendar year, the actual amounts associated with the Levelized Monthly Decommissioning Payments or Preliminary Monthly Decommissioning Payments, as applicable, during such calendar year shall be deemed to be equal to the estimated amounts associated with the Levelized Monthly Decommissioning Payments or Preliminary Monthly Decommissioning Payments, as applicable, that are included in the estimated Transmission Service Payments for such calendar year.

Section 14.3. Procedures for Billing Disputes.

(a) In the event of any Impasse or other Dispute with respect to the amount owed to Owner by Purchaser under this Agreement, Purchaser shall have no right to withhold payment of the Disputed amount pending resolution of the Dispute; provided, however, that, in the event such Dispute is resolved in favor of Purchaser, Owner shall complete the following tasks consistent with the resolution of such Dispute: (i) retroactively adjust all payments previously made by Purchaser; (ii) promptly refund all overpayments previously made by Purchaser, together with interest thereon in accordance with Section 14.2(c), in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing; and (iii) thereafter conform all future Invoices to reflect the resolution of such Dispute. Purchaser's payment of any Disputed amounts (A) shall not be deemed to be an acceptance or approval by Purchaser of the correctness or prudency of the costs reflected therein (provided that nothing herein shall alter the otherwise applicable burden of proof set forth in Section 8.1.4 for prudency challenges or time limit set forth in clause (b) below within which Purchaser has the right to challenge an Invoice) and (B) shall be without prejudice to any right or remedy that Purchaser may have under this Agreement, including under Section 8.1.4, to contest any such amount.

(b) Purchaser shall not have the right to challenge any Invoice or to bring any action of any kind challenging the propriety of any Invoice after the second (2nd) anniversary of the date payment of the Invoice was due; provided, however, that, in the case of an Invoice based upon cost estimates, such two (2)-year period shall be based upon the date such Invoice is reconciled to actual costs in a statement provided to Purchaser unless the challenge equally applied to such cost estimates, in which case such two (2)-year period shall be based upon the date on which such cost estimates was provided to Purchaser. If an Invoice is not rendered within two (2) years after the end of the calendar month during which such Invoice should have been rendered hereunder, then the right to payment of such Invoice is waived.

Section 14.4. Reporting of Revenue Credits. In the event Owner becomes aware of a material change in the revenue credits to be made to Purchaser in any calendar month as compared with the revenue credits contained in the applicable Annual Plan and Operating Budget, Owner shall promptly notify the Management Committee of the nature and amount of such revenue credits.

Section 14.5. Interest. All interest payable under this Section 14.5 shall be calculated pursuant to 18 C.F.R. § 35.19a(a), as such regulation (or any successor thereto) is in effect during the period during which such interest is due.

(a) Interest on refunds owed to Purchaser by Owner under Section 3.4(b), Section 9.2 or Section 14.2(c) shall begin to accrue on the amount subject to refund, as originally invoiced, from the earlier to occur of the due date or the date of payment of the monthly Invoices to which the refund relates and shall continue to accrue until the date of payment of such refund.

(b) Interest on surcharges owed to Owner by Purchaser under Section 3.4(b) or Section 14.2(c) shall begin to accrue on the surcharge from the due date of the monthly Invoices to which the surcharge relates and shall continue to accrue until the date of payment of such surcharge.

(c) Amounts not paid when due to either Owner or Purchaser under this Agreement (other than amounts owed pursuant to Section 3.4(b), Section 9.2 or Section 14.2(c)) shall bear interest from the date such amount was due until the date of payment of such overdue amount. For the avoidance of doubt, as illustrated in Attachment I, if all or a portion of the amount to which such interest relates is later refunded pursuant to this Agreement, then, in calculating that refund, such interest shall not be included in the refund. Refunds of overpayments owed to Purchaser by Owner under this Agreement (other than amounts owed pursuant to Section 3.4(b), Section 9.2 or Section 14.2(c)) shall begin to accrue interest on the amount subject to refund, as originally invoiced, from the earlier to occur of the due date or the date of payment of the monthly Invoices to which the overpayment relates and shall continue to accrue interest until the date of payment of such refund.

Section 14.6. Obligation to Make Payments. The Parties acknowledge and agree that, except as set forth in Section 4.3.1, Section 7.4.1, Section 8.1.4, Section 14.7, Section 15.4(h) and Section 16.4, no cause or event whatsoever shall excuse or suspend Purchaser's obligation to pay Transmission Service Payments, Owner's estimate of the amounts owed to Owner by Purchaser under Section 3.3, the Decommissioning Estimate, or any other amounts payable by Purchaser under this Agreement. The Parties also acknowledge and agree that no cause or event whatsoever shall excuse or suspend any amounts payable by Owner under this Agreement.

Section 14.7. Offsets. Except as otherwise provided in Section 3.4(b), Section 9.3.4, Section 9.3.5(d), Section 9.3.5(e) and Section 15.4(h), neither of the Parties shall be entitled to deduct and setoff payment of any amount owed to such Party under this Agreement against payment of any amount owing under this Agreement or any other agreement between the Parties or their Affiliates.

ARTICLE 15

EVENTS OF DEFAULT AND REMEDIES

Section 15.1. Purchaser Defaults. Except to the extent excused as a result of an event of Force Majeure in accordance with Article 16, the occurrence of one or more of the following events shall constitute a default by Purchaser under this Agreement (a "Purchaser Default"):

(a) Purchaser's failure to pay any amount due to Owner under this Agreement by the due date, which failure is not cured within thirty (30) days after the receipt by Purchaser of a demand from Owner that such amount is due and owing and has not been timely paid.

(b) Purchaser's failure to comply in any material respect with the provisions of Article 17.

(c) Purchaser's failure to perform or comply with any of its obligations under this Agreement, other than those described in clauses (a) and (b) above, or under the Letter Agreement, in each case, in any material respect, and, if such failure is susceptible to cure, such failure continues for thirty (30) days after the receipt by Purchaser of written notice thereof from Owner, unless such cure shall reasonably require a longer period, in which case Purchaser shall be provided such additional period as necessary to complete such cure so long as Purchaser has promptly commenced such cure and thereafter diligently pursues and completes such cure.

(d) Any representation or warranty made by Purchaser in this Agreement is false or misleading at the time made and such inaccuracy has a material adverse effect on the ability of Owner to perform its obligations under this Agreement, individually or in the aggregate, or on the business, operations or financial condition of Owner.

(e) Any Insolvency Event occurs with respect to Purchaser.

Section 15.2. Owner Defaults. Except to the extent excused as a result of an event of Force Majeure in accordance with Article 16, the occurrence of one or more of the following events shall constitute a default by Owner under this Agreement (an "Owner Default"):

(a) Owner's failure to pay any amount due to Purchaser under this Agreement by the due date, which failure is not cured within thirty (30) days after the receipt by Owner of a demand from Purchaser that such amount is due and owing and has not been timely paid.

(b) An Owner Delay occurs and the Operation Phase has not commenced by the fifth (5th) anniversary of Owner's Initial Deadline (which fifth (5th) anniversary shall not be subject to extension for any event of Force Majeure).

(c) Owner's failure to comply with the provisions of Section 5.1.2(a)(ii).

(d) Owner's failure to comply with the provisions of Section 5.1.2(a)(iii).

(e) Owner's failure to comply with the provisions of Section 5.1.2(e).

(f) Owner's failure to comply with the provisions of Section 5.6; provided that such failure also constitutes a default under any Loan Agreement (or any agreement entered into by Owner with a Financing Party or any equity commitment or similar agreement entered into by any Affiliate of Owner with a Financing Party in connection therewith).

(g) Owner's failure to comply with the provisions of Section 5.7(a).

(h) A Non-Excused Outage occurs.

(i) Owner's failure to comply in any material respect with the provisions of Article 17.

(j) Owner's failure to perform or comply with any of its obligations under this Agreement, other than those described in clauses (a), (b), (c), (d), (e), (f), (g), (h) and (i) above, or under the Letter Agreement, in each case, in any material respect, and, if such failure is susceptible to cure, such failure continues for thirty (30) days after the receipt by Owner of written notice thereof from Purchaser, unless such cure shall reasonably require a longer period, in which case Owner shall be provided such additional period as necessary to complete such cure so long as Owner has promptly commenced such cure and thereafter diligently pursues and completes such cure.

(k) Any representation or warranty made by Owner in this Agreement is false or misleading at the time made and such inaccuracy has a material adverse effect on the ability of Purchaser to perform its obligations under this Agreement, individually or in the aggregate, or on the business, operations or financial condition of Purchaser.

(l) Any Insolvency Event occurs with respect to Owner.

Section 15.3. Remedies Upon Purchaser Default. Upon the occurrence of a Purchaser Default and at any time thereafter so long as the same is continuing, Owner shall be entitled, to the extent permitted by Applicable Law, to exercise one or more of the following remedies, as Owner shall elect:

(a) In the case of a Purchaser Default pursuant to Section 15.1(a), and subject to Section 5.8, Owner may terminate this Agreement by written notice to Purchaser as of a date that is not less than ninety (90) days after the date of such notice.

(b) In the case of a Purchaser Default pursuant to Section 15.1(a), and subject to Section 5.8, Owner may suspend all or part of Owner's obligations or Purchaser's rights under this Agreement during the period during which such Purchaser Default is continuing. During any such period of suspension occurring after the Commercial Operation Date, (i) Purchaser shall not be entitled to schedule, and shall not schedule, any transactions over the Northern Pass Transmission Line and (ii) the OASIS Provider shall be directed to post any portion of the transmission capacity available over the Northern Pass Transmission Line and to attempt to sell such capacity to one or more third parties consistent with Article 10. The proceeds of any capacity releases and transmission resales made pursuant to the foregoing sentence and received by Owner, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with this Section 15.3(b), shall be credited against any accrued but unpaid payment obligation of Purchaser to Owner hereunder. Any proceeds in excess of such accrued but unpaid payment obligation of Purchaser shall be credited in accordance with Section 10.4; provided, however, that Owner shall have no liability for, or obligation to credit against any accrued but unpaid payment obligation of Purchaser to Owner hereunder, amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Section 15.3(b).

(c) Subject to Article 19 and this Section 15.3, as applicable, Owner may recover all damages suffered by Owner that are due to a Purchaser Default, including, for the avoidance of doubt, any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover any amounts owed to Owner by Purchaser under this Agreement.

(d) Owner may exercise and enforce any and all of its rights and remedies under the Purchaser Guaranty or any other financial assurances held by Owner.

(e) Owner may exercise any and all other rights and remedies that may be available to Owner at law or in equity, unless expressly prohibited or otherwise restricted by Article 19 or any other provision of this Agreement. Notwithstanding the foregoing sentence, Owner shall have no right to (i) terminate this Agreement based upon a Purchaser Default, except as provided in clause (a) above, or (ii) suspend transmission service under this Agreement based upon a Purchaser Default, except as provided in clause (b) above.

Section 15.4. Remedies Upon Owner Default. Upon the occurrence of an Owner Default and at any time thereafter so long as the same is continuing, Purchaser shall be entitled, to the extent permitted by Applicable Law, to exercise one or more of the following remedies, as Purchaser shall elect:

(a) In the case of an Owner Default pursuant to Section 15.2(b) or Section 15.2(d), and subject to Section 5.8, Purchaser may exercise all of its rights and remedies contemplated by Section 4.3.1, including the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice. Such rights and remedies shall collectively be the sole and exclusive remedy of Purchaser with respect to such Owner Default as provided in Section 4.3.1(b)(iii).

(b) In the case of an Owner Default pursuant to Section 15.2(c), and subject to Section 5.8, this Agreement shall terminate in accordance with Section 3.3.5 without liability to either Party (except for any accrued but unpaid payment obligations and any indemnification obligations under this Agreement). Such termination shall be the sole and exclusive remedy of Purchaser with respect to such Owner Default.

(c) In the case of an Owner Default pursuant to Section 15.2(f), and subject to Section 5.8, Purchaser may terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice. Such termination shall be the sole and exclusive remedy of Purchaser with respect to such Owner Default and any breach of Section 8.3(a) resulting from such Owner Default.

(d) In the case of an Owner Default pursuant to Section 15.2(h), and subject to Section 5.8, Purchaser may exercise all of its rights and remedies contemplated by Section 7.4, including the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice if the Northern Pass Transmission Line is entirely out-of-service for the five (5)-year period following a Non-Excused Outage (which five (5)-year period shall not be subject to extension for any event of Force Majeure). Such rights and remedies shall collectively be the sole and exclusive remedy of Purchaser with respect to such Owner Default as provided in Section 7.4.4.

(e) Upon the written agreement of the Parties on the amount of the damages suffered by Purchaser as a result of an Owner Default, or the determination of such amount pursuant to the dispute resolution provisions herein, then, if Owner shall not have paid such amount by the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, Purchaser may exercise and enforce any and all of its rights and remedies under the Purchaser's Security Documents or against Purchaser's Lien.

(f) Subject to the limitations provided in Section 4.3.1(b)(iii), Section 7.4.4, Article 19 or this Section 15.4, as applicable, Purchaser may recover all damages suffered by Purchaser as a result of an Owner Default, including, for the avoidance of doubt, any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement.

(g) Purchaser may exercise and enforce any and all of its rights and remedies under the Owner Guaranty or any other financial assurances held by Purchaser.

(h) In the event the Parties agree in writing upon the amount of the damages suffered by Purchaser as a result of an Owner Default (i) due to a Non-Excused Outage or (ii) pursuant to Section 21.2, or such amount has been determined pursuant to the dispute resolution provisions herein, then, if Owner shall not have paid such amount by the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, Purchaser may deduct and setoff payment of such amount against any Transmission Service Payment.

(i) Purchaser may exercise any and all other rights and remedies that may be available to Purchaser at law or in equity, unless expressly prohibited or otherwise restricted by Article 19 or any other provision of this Agreement. Notwithstanding the foregoing sentence, Purchaser shall have no right to (i) terminate this Agreement based upon an Owner Default, except as provided in clauses (a), (c) and (d) above, or (ii) any reduction of or offset against payments under this Agreement based upon an Owner Default, except as contemplated by Section 7.4.1, Section 8.1.4, Section 14.7, Section 15.4(h) and Section 16.4, as applicable.

Section 15.5. Disputes. Any Dispute over whether or not an Owner Default or Purchaser Default has occurred shall be resolved in accordance with Article 18.

ARTICLE 16

FORCE MAJEURE

Section 16.1. Definition.

(a) "Force Majeure" means an event or circumstance that prevents a Party from performing its obligations under this Agreement, which event or circumstance is not within the reasonable control of such Party. Such events or circumstances shall include the following, but only to the extent they satisfy the foregoing condition: actions or inactions of any Governmental Authority; acts of God; war, terrorism, riot or insurrection; blockades; embargoes; sabotage; epidemics; explosions and fires; hurricanes, floods, blizzards, ice storms, thunderstorms and other abnormal weather conditions; national or regional general strikes, lockouts or other labor disputes. Force Majeure shall not include (i) changes in market conditions that affect the demand for, or supply of, electrical energy or capacity or transmission service, (ii) the acts or omissions of a third party, including contractors, customers, vendors and sub-contractors, except to the extent resulting from Force Majeure, (iii) economic hardship or (iv) the financial inability of any Person to perform its obligations.

(b) A Party shall not be required to settle any strike, walkout, lockout or other labor dispute on terms that, in the sole judgment of such Party, are contrary to its interest. The settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party involved in such dispute.

Section 16.2. Conditions.

(a) If and to the extent a Party is prevented by Force Majeure from performing, in whole or part, its obligations under this Agreement and such claiming Party gives notice and details of the Force Majeure to the other Party as soon as practicable, then such claiming Party shall be excused from the performance of its obligations hereunder (other than the obligation to make any payments or comply with Article 17); provided that the suspension of performance due to Force Majeure shall be of no greater scope than is required by such Force Majeure and shall be of no greater duration than is consistent with clause (b) below.

(b) Such claiming Party shall use commercially reasonable efforts to (i) seek to avoid and (ii) mitigate or remedy any Force Majeure in a commercially reasonable timeframe consistent with Good Utility Practice. Subject to the limitations provided in Section 16.3, all costs and expenses incurred by Owner to comply with its obligations under the foregoing sentence shall be recoverable under the Formula Rate in accordance with Article 8.

Section 16.3. Events of Loss.

(a) Owner shall notify Purchaser as soon as practicable, but in no event later than ten (10) days, after Owner becomes aware of a Loss Occurrence.

(b) The following provisions shall apply in the event of a Loss Occurrence during the Construction Phase:

(i) Promptly after, but no later than sixty (60) days following a Loss Occurrence, Owner shall prepare and submit to the Management Committee for review and approval a Construction Budget and Schedule inclusive of all projected Reconstruction Costs associated with such Loss Occurrence.

(ii) Subject to Purchaser's termination rights under Section 3.3.6 or Section 3.3.8, as applicable, and the rights of any Financing Party, Owner shall reconstruct or otherwise repair the Northern Pass Transmission Line in a manner consistent with Owner's rights and obligations under Section 5.1.2(a)(i) and Section 5.2.4(a); provided, however, that Owner shall not commence with such reconstruction or repair prior to the sixty-first (61st) day after the receipt by Purchaser's Manager of the proposed Construction Budget and Schedule described in clause (b)(i) above, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, the costs associated therewith. Any delays in reconstruction or repair due to Owner's compliance with the proviso to the first sentence of this clause (b)(ii) shall not constitute a violation of Good Utility Practice.

(c) The following provisions shall apply in the event of a Loss Occurrence during the Operation Phase:

(i) Promptly after, but no later than sixty (60) days following, a Loss Occurrence Owner shall prepare and submit to the Management Committee for review and approval a budget and schedule that sets forth all Reconstruction Costs and the expected timeline to complete the work required to reconstruct or otherwise repair the Northern Pass Transmission Line (the "Reconstruction Plan"), together with a statement for informational purposes that sets forth in reasonable detail the unamortized Rate Base calculated as of the date of such Loss Occurrence (the "Rate Base Calculation"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Reconstruction Plan or Rate Base Calculation.

(ii) The Management Committee shall promptly review the proposed Reconstruction Plan, and may approve such Reconstruction Plan in whole or in part. If an Impasse occurs with respect to the proposed Reconstruction Plan (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.9 or Section 3.3.10, as applicable, the proposed Reconstruction Plan, with any changes agreed upon by the Management Committee, shall be deemed to be (A) in effect upon the sixty-first (61st) day after the receipt by Purchaser's

Manager of such Reconstruction Plan and Rate Base Calculation and (B) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

(iii) Subject to Purchaser's termination rights under Section 3.3.9 or Section 3.3.10, as applicable, and the rights of any Financing Party, Owner shall reconstruct or otherwise repair the Northern Pass Transmission Line in a manner consistent with Owner's rights and obligations under Section 16.2(b) and clause (c)(iv) below; provided, however, that Owner shall not commence with such reconstruction or repair prior to the sixty-first (61st) day after the receipt by Purchaser's Manager of the proposed Reconstruction Plan and the Rate Base Calculation described in clause (c)(i) above, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, the costs associated therewith. Any delays in reconstruction or repair due to Owner's compliance with the proviso to the first sentence of this clause (c)(iii) shall not constitute a violation of Good Utility Practice.

(iv) Owner shall use commercially reasonable efforts not to exceed the budgeted amounts set forth in the Reconstruction Plan; provided, however, that, consistent with Section 16.2(b), all Reconstruction Costs, whether or not set forth in such Reconstruction Plan, shall be recoverable under the Formula Rate in accordance with Article 8.

Section 16.4. Extended Outages; Extended Term.

(a) If an event of Force Majeure in the United States renders the Northern Pass Transmission Line entirely out-of-service for more than three hundred sixty-five (365) consecutive days (an "Extended Outage"), then Purchaser shall have no obligation to pay the ROE portion of the Transmission Service Payment or depreciation expenses from and after the final day of such three hundred sixty-five (365)-day period until such time as the Northern Pass Transmission Line has been placed back in-service at an operating condition sufficient to enable the provision of Firm Transmission Service, but Purchaser shall continue to pay all other portions of the Transmission Service Payments, including the debt component, Taxes and O&M Costs, during such Extended Outage.

(b) Following an Extended Outage:

(i) the Term shall be extended for a period equal to the entire period of time during which the Northern Pass Transmission Line was out-of-service due to such Extended Outage; and

(ii) the ROE portion of the Transmission Service Payments and depreciation expenses shall resume and Owner shall recover the ROE on the remaining transmission investment and such depreciation, in each case, over the period commencing on such resumption date and ending on the last day of the penultimate year of the extended Term.

(c) From and after the first calendar month following the Commercial Operation Date, if an event of Force Majeure causes the availability of the Northern Pass Transmission Line ("Average Availability") to fall below the Minimum Average Availability, as measured over any calendar month, then the Term shall be extended for an additional calendar month, except where the Term has already been extended for such unavailability of the Northern Pass Transmission Line under clause (b)(i) above.

(d) Any costs and expenses that are incurred during any extended Term contemplated by clause (b)(i) or (c) above shall be recoverable under the Formula Rate in accordance with Article 8.

(e) For purposes of this Section 16.4, the Average Availability for any measurement period shall be calculated using the arithmetic average of the Hourly Availability values for all hours in such measurement period.

Section 16.5. Insurance Proceeds. Subject to the rights of any Financing Party, if and to the extent Owner receives or is entitled to receive proceeds from insurance or other amounts payable in connection with any Force Majeure (including any Loss Occurrence), Owner shall then credit such amounts (excluding any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to such Force Majeure) to Purchaser under the Formula Rate, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts. Owner shall use commercially reasonable efforts to pursue the collection or recovery of any such amounts and otherwise seek to enforce any rights to which it is entitled with respect to any Force Majeure (including any Loss Occurrence).

ARTICLE 17

FINANCIAL ASSURANCES

Section 17.1. Parent Guaranty.

Section 17.1.1. Purchaser's Guaranty.

(a) Purchaser shall cause Hydro-Québec to execute and deliver to Owner, no later than the Execution Date, a payment guaranty, substantially in the form attached hereto as Attachment E-1, for the benefit of Owner (the "Purchaser Guaranty"), which Purchaser Guaranty shall guaranty payment of (i) all present and future amounts owed by Purchaser to Owner hereunder (excluding obligations owed by Purchaser to Owner for Decommissioning Costs); provided that the aggregate liability of Hydro-Québec for such amounts shall be subject to the Stated Cap set forth in the Purchaser Guaranty, which Stated Cap shall be equal to the Determined Cap determined in accordance with this Section 17.1.1 (the "Capped Guaranteed Obligations"), (ii) the Decommissioning Liquidated Damages, as provided in the Purchaser Guaranty, and (iii) certain costs of enforcement, as provided in the Purchaser Guaranty.

(b) In accordance with clauses (g) and (i) below, as applicable, Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty with a revised Stated Cap from time to time. Upon the receipt by Owner of each Purchaser Guaranty that has been reissued in compliance with clause (g) or (i) below, as applicable, the previously issued Purchaser Guaranty shall terminate, subject to clause (e) below.

(c) Subject to Section 23.1, Purchaser shall cause each Purchaser Guaranty to be and remain in full force and effect at all times from and after the commencement of the Construction Phase and until the earlier to occur of (i) the date on which the obligations guaranteed thereunder have been fully, finally and indefeasibly paid, or, with respect to the obligations guaranteed thereunder with respect to the payment of the Decommissioning Liquidated Damages, the termination date therefor, as set forth in the Purchaser Guaranty, and (ii) subject to clause (e) below, the date on which a Purchaser Guaranty shall have been reissued in compliance with clause (g) or (i) below, as applicable.

(d) The Determined Cap shall be an amount determined as follows:

(i) until the first Redetermination Date, the Determined Cap shall equal Fifty-Five Million U.S. Dollars (U.S. $55,000,000);

(ii) as of each Redetermination Date during the period commencing on the first Redetermination Date and ending on the last day of the Construction Phase, the Determined Cap shall equal (A) the Owner’s Costs Plus EAFUDC that, if applicable, would be payable upon an early termination of this Agreement as of such Redetermination Date, with the "Owner’s Costs" component of the Owner’s Costs Plus EAFUDC to be determined by reference to (1) all amounts described in clauses (a) and (b) of the definition of "Owner’s Costs" that have been incurred by Owner with respect to the Northern Pass Transmission Line prior to such Redetermination Date (whether payable before or after such Redetermination Date, and including reasonable forecasts of such amounts to the extent the actual amounts thereof are unknown to Owner as of the date of the applicable Redetermination Certificate), subject to the exclusions to such definition, plus (2) the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 5.2.3 concurrently with the delivery to the Management Committee of the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date; plus (B) the budgeted Construction Costs, as set forth in the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date; minus (C) the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under any Purchaser Guaranty prior to the date of the applicable Redetermination Certificate; provided, however, that, if Purchaser shall have submitted any matter with respect to Estimated Wind-Down Costs to the Management Committee for resolution under Section 5.2.3(b) and the Management Committee shall not have resolved such matter prior to the date of such Redetermination Certificate, then, until the Management Committee shall have agreed upon such Estimated Wind-Down Costs (or such Estimated Wind-Down Costs shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Estimated Wind-Down Costs shall be deemed equal to the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 5.2.3 concurrently with the delivery to the Management Committee of the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date. If the Estimated Wind-Down Costs are subsequently adjusted by the agreement of the Management Committee (or pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), then Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty in accordance with clause (i) below. For the avoidance of doubt, the budgeted Construction Costs described in the foregoing clause (B) shall be subject to the approval of the Management Committee as and to the extent provided in Section 5.2.2(b).

(iii) as of each Redetermination Date during the Operation Phase, the Determined Cap shall equal (A) the Owner's Costs Plus EAFUDC that, if applicable, would be payable upon an early termination of this Agreement as of such Redetermination Date, with the "Owner's Costs" component of the Owner's Costs Plus EAFUDC to be determined by reference to (1) all amounts described in clauses (a) and (b) of the definition of "Owner's Costs" that have been incurred by Owner with respect to the Northern Pass Transmission Line prior to such Redetermination Date (whether payable before or after such Redetermination Date, and including reasonable forecasts of such amounts to the extent the actual amounts thereof are unknown to Owner as of the date of the applicable Redetermination Certificate), subject to the exclusions to such definition, plus (2) the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 6.4 concurrently with the delivery to the Management Committee of the Capital Plan for the upcoming Contract Year after such Redetermination Date; plus (B) the sum of (1) the budgeted amounts set forth in the Capital Plan for the upcoming Contract Year after such Redetermination Date, plus (2) the budgeted amounts set forth in the Multiyear Outlook for the second and third Contract Years after such Redetermination Date (the sum of the amounts set forth in the foregoing clauses (1) and (2), the "Budgeted Amount"); minus (C) the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under any Purchaser Guaranty prior to the date of the applicable Redetermination Certificate; provided, however, that:

(1) if Purchaser shall have submitted any matter with respect to Estimated Wind-Down Costs to the Management Committee for resolution under Section 6.4(b) and the Management Committee shall not have resolved such matter prior to the date of such Redetermination Certificate, then, until the Management Committee shall have agreed upon such Estimated Wind-Down Costs (or such Estimated Wind-Down Costs shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Estimated Wind-Down Costs shall be deemed equal to the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 6.4 concurrently with the delivery to the Management Committee of the most recent Annual Plan and Operating Budget for the upcoming Contract Year after such Redetermination Date;

(2) if the Management Committee shall not have approved such Capital Plan or Multiyear Outlook (or such Capital Plan or Multiyear Outlook shall not have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto) prior to the date of such Redetermination Certificate, then, until the Management Committee shall have approved such Capital Plan or Multiyear Outlook (or such Capital Plan or Multiyear Outlook shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Budgeted Amount shall be deemed equal to the sum of the budgeted amounts for the upcoming three (3) Contract Years after such Redetermination Date, as set forth in (x) the Multiyear Outlook most recently approved by the Management Committee (or determined pursuant to the dispute resolution provisions in this Agreement in the event of an

Impasse with respect thereto) or (y) if no such Multiyear Outlook exists, then the Multiyear Outlook most recently delivered to the Management Committee under Section 6.3; and

(3) if the Estimated Wind-Down Costs, Capital Plan or Multiyear Outlook is subsequently adjusted by the agreement of the Management Committee (or pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), then Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty in accordance with clause (i) below.

(iv) in the case of each of clauses (d)(ii) and (d)(iii) above, (A) the adjustments required pursuant to Section 3.4(c) shall apply *mutatis mutandis* to the Determined Cap and (B) the dollar amount of the Determined Cap shall be rounded up to the nearest One Million Dollars ($1,000,000), unless such dollar amount is Zero Dollars ($0).

(e) Notwithstanding anything in this Section 17.1.1 to the contrary, if, prior to any Redetermination Date, a claim for Capped Guaranteed Obligations has been submitted by Owner to Hydro-Québec under any Purchaser Guaranty (an "Existing Guaranty") but not yet paid by Hydro-Québec thereunder (an "Outstanding Claim"), then such Existing Guaranty shall not terminate upon the reissuance of a new Purchaser Guaranty, but shall continue in full force and effect solely with respect to such Outstanding Claim and the costs of enforcement thereof, as provided in such Existing Guaranty and subject to the Stated Cap set forth in such Existing Guaranty (as reduced by the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under such Existing Guaranty prior to such Redetermination Date ("Prior Claims")). With respect to the Purchaser Guaranty subsequently reissued by Hydro-Québec in accordance with clause (g) or (i) below for such Redetermination Date (which reissued Purchaser Guaranty shall be in addition to the Existing Guaranty until the Existing Guaranty terminates in accordance with this clause (e)), and for purposes of calculating the Determined Cap (as redetermined in accordance with clause (d) above) to be set forth in such reissued Purchaser Guaranty, the Determined Cap shall be reduced to the extent, if any, Hydro-Québec shall have accepted, in writing, liability for such Outstanding Claim prior to the reissuance of such Purchaser Guaranty. If and when Hydro-Québec pays the lesser of the (i) the entire Outstanding Claim (or the portion of such Outstanding Claim that satisfies in full such Outstanding Claim, as mutually agreed by Hydro-Québec and Owner or for which Hydro-Québec is found liable pursuant to the final order of a court of competent jurisdiction) and (ii) the Stated Cap set forth in such Existing Guaranty (as reduced by the sum of all Prior Claims) ("Satisfying Amount"), then, if and to the extent an additional adjustment is required to the Stated Cap set forth in such reissued Purchaser Guaranty, Purchaser shall cause Hydro-Québec to reissue such Purchaser Guaranty in accordance with clause (i) below. If and when (A) Hydro-Québec pays the Satisfying Amount, together with the costs of enforcement thereof, as provided in such Purchaser Guaranty, or (B) Hydro-Québec is found not to be liable for such Outstanding Claim pursuant to the final order of a court of competent jurisdiction, then, in each case, the Existing Guaranty shall terminate.

(f) The amount of the Determined Cap, as redetermined as of each Redetermination Date, as provided in clause (d) above, shall be set forth in a certificate of Owner, showing the calculation thereof in reasonable detail (a "Redetermination Certificate"). With respect to each Redetermination Date during the Construction Phase, Owner shall deliver a Redetermination Certificate to Purchaser within thirty (30) days after the date on which Owner shall have delivered the applicable Construction Budget and Schedule to Purchaser's Manager under Section 5.2.2. With respect to each Redetermination Date during the Operation Phase, Owner shall deliver a Redetermination Certificate to Purchaser by the earlier to occur of (i) seventy-five (75) days after the date on which Owner shall have delivered the applicable Capital Plan and Multiyear Outlook to Purchaser's Manager under Section 6.3 and (ii) thirty (30) days after the date on which the Management Committee shall have approved such Capital Plan and Multiyear Outlook (or such Capital Plan and Multiyear Outlook shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto). Purchaser promptly shall acknowledge such Redetermination Certificate and deliver such acknowledged Redetermination Certificate to Hydro-Québec.

(g) Subject to Section 23.1, Purchaser shall cause Hydro-Québec, following the receipt by Purchaser of each Redetermination Certificate (regardless of any Impasse or other Dispute with respect to the Redetermination Certificate), to reissue the Purchaser Guaranty, as provided herein, with a revised Stated Cap equal to the Determined Cap, as so redetermined in accordance with clause (d) above, but subject to clause (e) above, and as set forth in such Redetermination Certificate, which Purchaser Guaranty shall be effective as of the date of issuance. Provided that a Redetermination Certificate is provided to Purchaser, the failure of Purchaser to acknowledge such Redetermination Certificate, or of Hydro-Québec to reissue such Purchaser Guaranty with such revised Stated Cap, as provided in this clause (g), within forty-five (45) days following the receipt by Purchaser of such Redetermination Certificate, shall be deemed to be a termination by Purchaser of this Agreement under Section 3.3.8 or Section 3.3.10, as applicable, unless Section 3.3.6 is applicable.

(h) If Owner fails to provide any Redetermination Certificate required by clause (f) above within fifteen (15) days after the receipt by Owner of written notice of such failure from Purchaser, Purchaser may provide such Redetermination Certificate to Hydro-Québec, with a copy to Owner, and Purchaser shall cause Hydro-Québec thereafter to reissue the Purchaser Guaranty in accordance with clause (g) above, with a revised Stated Cap equal to the Determined Cap, as so redetermined in accordance with clause (d) above, but subject to clause (e) above, and as set forth in such Redetermination Certificate, which Purchaser Guaranty shall be effective as of the date of issuance. Owner shall be entitled to Dispute any amount set forth in such Redetermination Certificate in accordance with Section 18.1(b).

(i) Without limiting the provisions of Section 5.2.2(b) or Section 8.1.4(c), Purchaser's acknowledgement or issuance of a Redetermination Certificate or Hydro-Québec's issuance of a Purchaser Guaranty shall be without prejudice to any right or remedy that Purchaser may have under this Agreement to contest any amount set forth in a Redetermination Certificate, and none of the foregoing actions by Purchaser or Hydro-Québec shall be construed in any way to create a presumption that the Redetermination Certificate or Determined Cap is correct. Upon resolution of any Dispute as to whether or not the Determined Cap set forth in a Redetermination Certificate is mathematically correct or was calculated in accordance with clause (d) or (e) above, or resolution of any Impasse with respect to the Estimated Wind-Down Costs, Capital Plan or Multiyear Outlook, in each case, as contemplated by this Section 17.1.1, Purchaser shall cause Hydro-Québec to reissue the

Purchaser Guaranty, as provided herein, with a revised Stated Cap equal to the Determined Cap, as so determined by the agreement of the Management Committee or pursuant to the dispute resolution provisions in this Agreement, but subject to clause (e) above, which Purchaser Guaranty shall be effective as of the date of issuance. The failure of Hydro-Québec to reissue such Purchaser Guaranty with such revised Stated Cap, as provided in this clause (i), within forty-five (45) days following the resolution of any such Dispute or Impasse, shall be deemed to be a termination by Purchaser of this Agreement under Section 3.3.8 or Section 3.3.10, as applicable, unless Section 3.3.6 is applicable.

Section 17.1.2. Owner's Guaranty. Owner shall (a) cause each of Northeast Utilities and NSTAR to execute and deliver to Purchaser, no later than the Execution Date, a payment guaranty, substantially in the form attached hereto as Attachment E-2, for the benefit of Purchaser (each an "Owner Guaranty"), and (b) subject to Section 23.1, cause each such Owner Guaranty to be and remain in full force and effect at all times from and after the Commercial Operation Date and until the amounts guaranteed thereunder have been fully, finally and indefeasibly paid. The Owner Guaranty to be executed and delivered by Northeast Utilities shall be in the maximum principal amount equal to Twenty-Five Million Dollars ($25,000,000) multiplied by the ratio of Northeast Utilities' beneficial ownership interest in Owner to the aggregate beneficial interests in Owner owned by Northeast Utilities and NSTAR, and the Owner Guaranty to be executed and delivered by NSTAR shall be in the maximum principal amount equal to Twenty-Five Million Dollars ($25,000,000) multiplied by the ratio of NSTAR's beneficial ownership interest in Owner to the aggregate beneficial interests in Owner owned by Northeast Utilities and NSTAR. Purchaser agrees to cooperate with Northeast Utilities and NSTAR, at their written request, to amend the Owner Guaranties from time to time to amend the maximum principal amount of each such Owner Guaranty in proportion to the respective beneficial ownership interests in Owner owned by Northeast Utilities and NSTAR, such that the aggregate principal amount of the Owner Guaranties issued by Northeast Utilities and NSTAR at all times shall equal Twenty-Five Million Dollars ($25,000,000) (less any amounts drawn under such Owner Guaranties).

Section 17.2. Purchaser's Lien.

Section 17.2.1. Security Documents. No later than the Distribution Date, as additional security for Owner's performance of its obligations hereunder, including payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2, Owner shall (a) execute, deliver, and record a mortgage and security agreement and all other agreements, documents, or instruments required or customary to provide Purchaser with a fully perfected security interest and mortgage lien in and to (i) the Northern Pass Transmission Line, and (ii) all real property rights and related personal property rights, contractual rights, Governmental Approvals, or other rights of Owner relating to the Northern Pass Transmission Line and the AC Upgrades (collectively, the "Purchaser Mortgage"), (b) execute and deliver a security agreement and all other agreements, documents, or instruments required or customary to provide Purchaser with a fully perfected security interest in and to (i) any material contracts entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, and (ii) all of Owner's other assets relating to the Northern Pass Transmission Line and the AC Upgrades, including all personal property rights, contractual rights, Governmental Approvals, or other rights of Owner to develop, procure, construct, operate, and maintain the Northern Pass

Transmission Line (collectively, the "Security Agreement"), and (c) cause each of its members to grant to Purchaser a present and continuing perfected lien on, and security interest in, all of the equity interests in Owner (collectively, the "Membership Pledges," and collectively with the Purchaser Mortgage and the Security Agreement, "Purchaser's Security Documents"). The Purchaser's Security Documents shall be based upon the agreements securing Owner's obligations under the Construction Loan Agreement, but shall not include any representations, warranties, covenants, or restrictions other than those that are reasonably required with respect to the creation, validity, perfection, protection or enforcement of Purchaser's security interests in the assets and property described in this Section 17.2.1 or as may otherwise be reasonably satisfactory to Purchaser, Owner, and the Financing Parties. The Purchaser's Security Documents shall provide that any such document may be assigned by Purchaser solely to the assignee of Purchaser pursuant to a permitted assignment of this Agreement. Subject to the rights of any Financing Parties, Owner shall cause the mortgage, liens and security interests created pursuant to Purchaser's Security Documents (collectively, "Purchaser's Lien") to be maintained in full force and effect at all times following the Distribution Date and until the later to occur of the expiration or earlier termination of the Term or the date on which any accrued but unpaid payment obligation of Owner to Purchaser hereunder shall have been fully, finally and indefeasibly satisfied. Promptly following such later date, Purchaser shall release the Purchaser's Lien. The granting of Purchaser's Lien shall not be to the exclusion of, or be construed to limit, the amount of any claims, causes of action or other rights accruing to Purchaser by reason of any breach by Owner under this Agreement, an Owner Default or the termination of this Agreement.

Section 17.2.2.Subordination. Purchaser's Lien shall be subordinate in right of priority and remedies only to the interests of the Financing Parties, to the extent of the Project Debt Obligations, but shall be superior in priority to all other indebtedness of Owner secured by the assets subject to the Purchaser's Security Documents. The subordination of Purchaser's Lien shall be effective on the terms and conditions set forth in Attachment F without necessity of the execution by Purchaser of further instruments to effectuate such subordination (provided that Purchaser's Security Documents shall be subject to the terms and conditions set forth in Attachment F), but Purchaser agrees to execute and deliver, at the request of any Financing Party, such documents or instruments as may be reasonably required to confirm such subordination on the terms and conditions set forth in Attachment F and otherwise on terms and conditions reasonably required by the Financing Parties. Solely for purposes of the automatic subordination provided for in this Section 17.2.2, the principal amount of the Project Debt Obligations to which Purchaser's Lien is subordinate shall be deemed to be equal to fifty percent (50%) of Owner's total capitalization; provided that any documents or instruments executed by Purchaser, at the request of any Financing Party, pursuant to the second sentence of this Section 17.2.2 shall specify the maximum actual principal amount of the Project Debt Obligations (consistent with Owner's obligations under Section 5.6 and Section 8.3(a)) to which Purchaser's Lien is subordinate. No later than the Distribution Date, Purchaser shall execute and deliver, at the request of Hydro-Québec Lender, a subordination agreement or intercreditor agreement with Hydro-Québec Lender with respect to Purchaser's Lien on the terms and conditions set forth in Attachment F and otherwise reasonably satisfactory to Purchaser and Hydro-Québec Lender. In addition, no later than the date on which funds are initially distributed by the Term Loan Lender under the Term Loan Agreement, or, if applicable, by an Additional Lender under the loan and credit agreements entered into by Owner with respect to any Additional Financing that such

Additional Lender commits to provide, Purchaser shall, at Owner's request, cooperate and diligently negotiate with each Term Loan Lender or such Additional Lender the form of a subordination agreement or intercreditor agreement with respect to Purchaser's Lien, substantially on the terms and conditions set forth in Attachment F, with such other terms and conditions as may be customary for transactions of a similar nature and as may be reasonably required by the Term Loan Lender or such Additional Lender (any such agreement, the "Subordination Agreement").

Section 17.2.3.Recording. Upon or promptly after the Distribution Date, the Parties shall file and record, at the expense of Owner, the Purchaser Mortgage. In addition, Owner hereby agrees to take such further action and execute such further instruments as may be reasonably requested by Purchaser to confirm and continue the validity, priority, and perfection of Purchaser's Lien, and agrees to cooperate with Purchaser in the execution and filing of, and hereby authorizes the execution and filing of, such financing statements under the Uniform Commercial Code or other Applicable Law, as may be requested by Purchaser or required by Applicable Law, upon or promptly after such date, and to confirm and continue the validity, priority, and perfection of Purchaser's Lien.

Section 17.2.4.Transfer of Governmental Approval. The Purchaser's Security Documents shall provide that, in the event Purchaser acts to obtain title (directly or indirectly) to the Northern Pass Transmission Line by exercise of its rights thereunder, Owner shall cooperate diligently with Purchaser in connection with the transfer to Purchaser of all Governmental Approvals necessary to construct, own or operate the Northern Pass Transmission Line.

ARTICLE 18

DISPUTE RESOLUTION

Section 18.1. Referral to the Management Committee.

(a) Either Party may refer a Dispute (other than a Dispute over the matters described in Section 13.2(b)(iii)(A), Section 13.2(b)(iii)(B) and Section 13.2(b)(iii)(C)) to the Management Committee by written notice to the other Party of such referral ("Dispute Notice"); provided that, following an Impasse with respect to any matter upon which the Managers were unable to reach agreement or any Dispute that the Managers were unable to resolve, such matter or Dispute shall not be referred back to the Management Committee pursuant to this clause (a). Such Dispute Notice shall include a Position Statement. Each Party shall honor any reasonable request made by the other Party for information with regard to a Dispute.

(b) Subject to Section 18.2 and except as expressly provided otherwise in this Agreement, any Dispute that has not been timely resolved by the Management Committee, as provided in Section 13.9 (or any Dispute that may not be referred to the Management Committee, as described in clause (a) above), shall be finally resolved in accordance with Section 18.3.

(c) All negotiations pursuant to this Section 18.1 shall be deemed to be confidential and shall be treated as compromise and settlement negotiations, and no evidence with regard to any proposal made during such negotiations shall be admissible in any arbitration under Section 18.3 or in any other proceeding following such negotiations, including any FERC proceeding or filing contemplated by Section 18.2.

Section 18.2. Disputes to be Resolved by FERC. In the event a Dispute over any of the following matters is not resolved in accordance with Section 18.1(a), either Party shall have the right to file for relief with FERC, subject to Article 20, unless the Parties mutually agree to resolve such Dispute in accordance with Section 18.3 or by some other means:

(a) Any matter subject to challenge under Section 8.1.4;

(b) Any matter subject to challenge under Section 8.1.5;

(c) Any matter subject to challenge under Section 8.4(b);

(d) Any matter subject to challenge under Section 8.6(d);

(e) Any matter subject to challenge under Section 8.6(f);

(f) Any filing or Dispute under Article 9 or Article 10 (to the extent that Article 9 or Article 10 does not expressly require resolution under Section 18.3);

(g) Any matter subject to challenge under Article 20; or

(h) Any matter that is subject to the exclusive jurisdiction of FERC; provided that, in the event any Party objects to the reference of any such matter to FERC on the grounds that such matter is not subject to the exclusive jurisdiction of FERC, the matter shall be referred to FERC for resolution of the Dispute as to whether or not such matter is subject to the exclusive jurisdiction of FERC.

Nothing contained in this Agreement shall be construed as precluding a Party from filing any answer, protest or other opposition to any FERC filing made by the other Party, unless expressly prohibited under the terms of this Agreement.

Section 18.3. Arbitration.

Section 18.3.1. Arbitration of Technical Disputes.

(a) Within thirty (30) days after the Execution Date, the Parties shall propose the names of up to three (3) technical experts to act as Expert Arbitrators for Technical Disputes that may arise ("Expert Arbitrator Candidates"). A Party shall accept or reject any Expert Arbitrator Candidate proposed by the other Party within ten (10) Business Days after such proposal. The Parties shall continue to propose Expert Arbitrator Candidates until the panel of Expert Arbitrators is comprised of at least three (3) Expert Arbitrators (the "Panel"). The Parties shall agree upon the order of the Expert Arbitrators on the Panel. If any

Expert Arbitrator is no longer available to serve on the Panel or ceases to satisfy the criteria for an Expert Arbitrator, then the Parties shall promptly agree upon a suitable replacement.

(b) Once the period for resolution of a Dispute submitted to the Management Committee, as set forth in Section 18.1, has terminated without a resolution of such Dispute, or earlier if both Parties agree, and in the event the Dispute is technical in nature (a "Technical Dispute"), the Technical Dispute may be submitted by either Party (with concurrent notice of such submission to the other Party (a "Technical Dispute Notice")) for arbitration by an Expert Arbitrator (an "Expert Arbitration"). Any Party involved in the Technical Dispute may object to reference of the Technical Dispute to an Expert Arbitrator on the grounds that such Technical Dispute is not appropriate for resolution by Expert Arbitration by giving notice of such objection to the other Party within ten (10) Business Days after the receipt by such Party of the Technical Dispute Notice, whereupon an Expert Arbitrator selected in accordance with clause (c) below shall determine whether or not such Dispute is a Technical Dispute appropriate for resolution by Expert Arbitration. In the event the Expert Arbitration determines that the Dispute is a Technical Dispute appropriate for resolution by Expert Arbitration, such Dispute shall be resolved in accordance with this Section 18.3.1. Absent such determination, the Technical Dispute shall be finally resolved in accordance with Section 18.3.2.

(c) The Parties shall promptly confer as to which of the Expert Arbitrators on the Panel have the appropriate expertise to hear the Technical Dispute. Promptly thereafter, the Party referring the Technical Dispute to Expert Arbitration shall contact the first Expert Arbitrator on the Panel who the Parties mutually agree has such expertise. If such Expert Arbitrator has any financial interest in the outcome of any Dispute or is unavailable to serve in a timely fashion, then the other Expert Arbitrators on the Panel who the Parties mutually agree have such expertise shall be contacted in order until an Expert Arbitrator without any financial interest in the outcome of the Technical Dispute is available to hear the Technical Dispute in a timely fashion. If, for any reason, all of the Expert Arbitrators on the Panel without any financial interest in the outcome of any Dispute are unavailable to hear the Technical Dispute, or the Parties fail to agree that any of the available Expert Arbitrators on the Panel have the appropriate expertise to hear the Technical Dispute, then Parties shall have ten (10) days to agree upon a suitable Expert Arbitrator. If the Parties fail to agree, within such ten (10)-day period, upon an Expert Arbitrator to hear the Technical Dispute, then, on the request of either Party, the International Chamber of Commerce ("ICC") Center for Expertise shall appoint an Expert Arbitrator to hear the Technical Dispute.

(d) The arbitration of the Technical Dispute shall be conducted in New York, New York (or such other place to which the Parties mutually agree in writing), in accordance with ICC Rules for Expertise. The language of the arbitration of the Technical Dispute and of all documentation in the arbitration shall be English. The Expert Arbitrator may request information and documents from the Parties that he or she determines to be reasonably necessary to resolve the Technical Dispute. The Expert Arbitrator shall review evidence and other submissions by the Parties and, unless the Parties mutually agree otherwise, shall hold a one (1)-day hearing. The Parties and the Expert Arbitrator shall use commercially reasonable efforts to have the Expert Arbitrator render a final award as soon as possible, and if practicable, within ninety (90) days after his or her appointment. Such time period may be extended by the

Expert Arbitrator for good cause shown or by the written agreement of both Parties. The award of the Expert Arbitrator shall be in writing and shall briefly state the findings of fact and conclusions of law upon which it is based; it shall be final and binding on the Parties, and may be entered and enforced in any court having jurisdiction.

Section 18.3.2. Arbitration for Other Disputes.

(a) Disputes not covered by Section 18.3.1 shall be finally resolved by arbitration in accordance with the Rules of the ICC (the "Rules"), as in effect from time to time.

(b) The place of arbitration shall be New York, New York (or such other place to which the Parties mutually agree in writing). The language of the arbitration and of all documentation in the arbitration shall be English. If the amount in controversy is Five Million Dollars ($5,000,000) or less (including all claims and counterclaims), then the Dispute shall be decided by a single arbitrator who shall be agreed upon by the Parties within twenty (20) days after the receipt by a Party of a copy of a written demand for arbitration from the other Party. If the amount in controversy is more than Five Million Dollars ($5,000,000) (including all claims and counterclaims), then the Dispute shall be decided by three (3) neutral and impartial arbitrators, one of whom shall be appointed by each of the Parties in accordance with the Rules, and the third arbitrator, who shall chair the arbitral tribunal, shall be appointed by the Party-appointed arbitrators within fifteen (15) days after the appointment of the second arbitrator. In the event any arbitrator is not appointed within the time limit provided herein, such arbitrator shall be appointed by the ICC. Any arbitrator appointed by the ICC shall be a retired judge or a practicing attorney, with not less than fifteen (15) years of experience with large complex cases and who, if practicable, is an experienced arbitrator of disputes involving transmission facilities. All arbitrators shall be fluent in the English language. The Parties, with the consent of the arbitrator(s), shall be entitled to discovery of documents directly related to the issues in Dispute. The arbitrator(s) may also request additional information from the Parties. The arbitration shall be governed by the Federal Arbitration Act, 9 U.S.C. § 1 *et seq*. The award of the arbitrator(s) shall be in writing and shall briefly state the findings of fact and conclusions of law upon which it is based; it shall be final and binding on the Parties, and may be entered and enforced in any court having jurisdiction.

Section 18.3.3. Arbitral Awards; Fees and Expenses. No Expert Arbitrator or arbitrator is empowered to award damages in excess of compensatory damages and each Party expressly waives and foregoes any right to damages, claims, or remedies identified in Article 19. The fees and expenses of the Expert Arbitrator or arbitrator(s), as applicable, and the costs of the facilities required for the Expert Arbitration or arbitration, as applicable, shall be paid equally by the Parties, unless the award specifies a different division of such costs and expenses. Each Party shall be responsible for its own expenses, including attorneys' fees. Each of the Parties shall be afforded adequate opportunity to present information in support of its position on the Dispute being arbitrated.

Section 18.3.4. Confidentiality. All Disputes shall be resolved in a confidential manner. The Expert Arbitrator or arbitrator(s), as applicable, shall agree to hold any information received during the Expert Arbitration or arbitration, as applicable, in the strictest of confidence and shall not disclose to any non-party the existence, contents or results of the Expert Arbitration or arbitration, as applicable, or any other information about such Expert Arbitration or arbitration, as applicable. No Party shall disclose or permit the disclosure of any information about the evidence adduced or the documents produced by the other Party in such proceedings or about the existence, contents or results of the proceeding, except as (x) may be required by Applicable Law or a Governmental Authority, (y) may be necessary in an action in aid of such proceedings or for enforcement of an arbitral award, and (z) reasonably required for enforcement or interpretation of this Agreement by FERC to the extent any Dispute is brought to FERC as provided in Section 18.2. Before making any disclosure permitted by the foregoing clauses (x) and (y), the Party intending to make such disclosure shall give the other Party reasonable written notice in advance of the intended disclosure and afford the other Party a reasonable opportunity to protect its interests. The following information shall not be subject to the restrictions provided for in this Section 18.3.4:

(a) Information that is a matter of public knowledge at the time of its disclosure or is thereafter published in or otherwise ascertainable from a source available to the public without breach of this Agreement;

(b) Information that is obtained from a Person other than by or as a result of unauthorized disclosure; or

(c) Information that, prior to the time of disclosure, had been independently developed or obtained by the disclosing Party or its Affiliates independent of information obtained as a result of unauthorized disclosure.

Section 18.3.5. Arbitration Proceedings. Each Party shall proceed to conclude the Expert Arbitration or arbitration, as applicable, proceeding as quickly as reasonably possible. If a Party refuses to participate in any such proceeding, then the other Party may petition any court of law having proper jurisdiction for an order to compel Expert Arbitration or arbitration, as applicable. All costs and expenses incurred by the petitioning Party in enforcing such participation obligation shall be paid for by the refusing Party.

Section 18.3.6. Exclusive Remedies. Except for any Dispute to be resolved pursuant to Section 18.2, Expert Arbitration or arbitration, as applicable, under this Section 18.3 shall be the exclusive remedy for all Disputes arising under this Agreement that are not resolved by the Management Committee.

Section 18.4. Equitable Remedies. Notwithstanding anything herein to the contrary, prior to the appointment of an Expert Arbitrator under Section 18.3.1 or the arbitrator or arbitrators under Section 18.3.2, either Party may seek temporary injunctive relief in a court of law with jurisdiction over the Parties to maintain the status quo or prevent irreparable harm. Without prejudice to such provisional remedies as may be available under the jurisdiction of a court, the arbitrator(s) shall have full authority to grant provisional remedies or order the Parties to request that a court modify or vacate any temporary or preliminary relief issued by such court, and to award damages for the failure of any Party to respect the orders of the arbitrator(s) to that effect.

ARTICLE 19

LIMITATION OF REMEDIES

NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, NEITHER PARTY NOR ANY OF THEIR RESPECTIVE AGENTS, SUBCONTRACTORS, REPRESENTATIVES OR AFFILIATES SHALL BE LIABLE TO THE OTHER PARTY FOR PUNITIVE, CONSEQUENTIAL, SPECIAL, MULTIPLE, EXEMPLARY, INCIDENTAL OR INDIRECT DAMAGES OF ANY NATURE, INCLUDING THE FOLLOWING: LOSS OF REVENUE OR PROFIT FROM THE WHOLESALE SALE OF POWER; ADVERSE RATE IMPACTS ON RETAIL OR WHOLESALE CUSTOMERS OF EITHER PARTY OR THEIR RESPECTIVE AFFILIATES; LOSS OF A TAX BENEFIT OR TAX CREDIT; LOSS OF USE DAMAGES (EXCEPT AS EXPRESSLY CONTEMPLATED IN Section 4.3.1 OR Section 7.4 OR FOR ANY DIRECT DAMAGES SUFFERED BY PURCHASER AS A RESULT OF A BREACH BY OWNER OF ITS OBLIGATIONS UNDER Section 6.2, Article 10, Section 11.2 OR Article 12); COST OF REPLACEMENT POWER; COST OF REPLACEMENT TRANSMISSION SERVICE (EXCEPT AS EXPRESSLY CONTEMPLATED IN Section 4.3.1 OR Section 7.4); OR CLAIMS OF CUSTOMERS FOR LOSS OF POWER OR PRODUCTION, IN EACH CASE, ARISING OUT OF OR RELATING TO THE PERFORMANCE OF THIS AGREEMENT, AND WHETHER SUCH LIABILITY IS CLAIMED IN CONTRACT OR TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY, WARRANTY, FAILURE OF GOOD UTILITY PRACTICE OR ANY OTHER LEGAL OR EQUITABLE THEORY).

FOR THE AVOIDANCE OF DOUBT, THE PARTIES ACKNOWLEDGE AND AGREE THAT Section 4.3.1 OR Section 7.4 PROVIDE THE SOLE AND EXCLUSIVE REMEDIES FOR ANY LOSS OF USE CONTEMPLATED BY Section 4.3.1 OR Section 7.4 AND NOTHING IN Section 6.2, Article 10, Section 11.2 OR Article 12 SHALL SUPERSEDE, SUPPLEMENT OR AMEND SUCH SOLE AND EXCLUSIVE REMEDIES.

THIS Article 19 IS IN ADDITION TO THE SPECIFIC LIMITATIONS ON REMEDIES REFERENCED IN Article 15.

ARTICLE 20

MODIFICATION OF THIS AGREEMENT

Section 20.1. Certain Changes to Formula Rate. Notwithstanding anything herein to the contrary, nothing contained in this Agreement shall be construed as affecting in any way the right of Owner to make a unilateral filing at any time under Section 205 of the Federal Power Act or the regulations promulgated thereunder to change the Formula Rate. In the event of any such Section 205 filing, Purchaser shall have the right to oppose Owner's proposed changes to the Formula Rate in any FERC proceeding. In addition, notwithstanding anything herein to the contrary, nothing contained in this Agreement shall be construed as affecting in any way the right of Purchaser to file a complaint at any time under Section 206 of the Federal Power Act seeking to change the Formula Rate. Notwithstanding the foregoing provisions, no filing by Owner under Section 205 of the Federal Power Act or by either Party under Section 206 of the

Federal Power Act shall be permitted to the extent that it is inconsistent with the terms and conditions of this Agreement.

Section 20.2. Other Modifications. The Parties specifically intend and acknowledge and agree that, except as otherwise expressly provided in this Agreement, (a) this Agreement shall not be subject to amendment or other modification, absent the written agreement of both Parties and (b) neither Party shall be permitted to make a filing with FERC under any provision of the Federal Power Act or the regulations promulgated thereunder that seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any provision of this Agreement at any time during the Term, except to implement an amendment or other modification to this Agreement that has been reduced to writing and signed by both Parties. In addition, to the extent any third party, or FERC acting *sua sponte* seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any provision of this Agreement, the standard of review for any proposed amendment or other modification shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and as further defined in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S.Ct. 2733 (2008) and *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 130 S.Ct. 693 (2010).

ARTICLE 21

INDEMNIFICATION

Section 21.1. Purchaser Indemnity. Purchaser shall indemnify, defend and hold harmless Owner and Owner's Affiliates and their respective officers, directors, shareholders, managers, members, partners, agents, employees, representatives, and permitted successors and assigns (each, an "Owner Indemnified Party"), from and against any and all claims, demands, suits, proceedings, judgments, losses, liabilities, damages, in each case, resulting from any third-party claims, together with any costs and expenses (including reasonable attorneys' fees) incurred by any such Owner Indemnified Party, and arising out of (a) the performance by the OASIS Provider or the OASIS Administrator of capacity release functions and transmission resales pursuant to this Agreement or (b) the gross negligence, willful misconduct or criminal misconduct of Purchaser. Purchaser shall have no obligations under the immediately preceding sentence to the extent any claims, demands, suits, proceedings, judgments, losses, liabilities, damages, costs and expenses (including reasonable attorneys' fees) incurred by any such Owner Indemnified Party are caused by or arise from the gross negligence, willful misconduct or criminal misconduct of, or breach or default of contract by, an Owner Indemnified Party.

Section 21.2. Owner Indemnity. Owner shall indemnify, defend and hold harmless Purchaser and Purchaser's Affiliates and their respective officers, directors, shareholders, managers, members, partners, agents, employees, representatives, and permitted successors and assigns (each, a "Purchaser Indemnified Party"), from and against any and all claims, demands, suits, proceedings, judgments, losses, liabilities, damages, in each case, resulting from any third-party claims, together with any costs and expenses (including reasonable attorneys' fees) incurred by any such Purchaser Indemnified Party, and arising out of the gross negligence, willful misconduct or criminal misconduct of Owner, other than Excluded Claims.

Owner shall have no obligations under the immediately preceding sentence to the extent any claims, demands, suits, proceedings, judgments, losses, liabilities, damages, costs and expenses (including reasonable attorneys' fees) incurred by any such Purchaser Indemnified Party are caused by or arise from the gross negligence, willful misconduct or criminal misconduct of, or breach of contract by, a Purchaser Indemnified Party.

Section 21.3. Procedures. Promptly after the receipt by any Person seeking indemnification under this Article 21 (the "Indemnified Party") of written notice of the assertion of any claim by a third party with respect to any matter in respect of which indemnification may be sought hereunder (a "Third Party Claim"), the Indemnified Party shall give written notice (the "Indemnification Notice") to the Party from which indemnification is sought (the "Indemnifying Party"), and shall thereafter keep the Indemnifying Party reasonably informed with respect thereto; provided, however, that the failure of the Indemnified Party to give the Indemnifying Party notice as provided herein shall not relieve the Indemnifying Party of any of its obligations hereunder, except to the extent that the Indemnifying Party is materially prejudiced by such failure. The Indemnifying Party shall be entitled to assume the defense of any Third Party Claim by written notice to the Indemnified Party of such intention given within thirty (30) days after the receipt by the Indemnifying Party of the Indemnification Notice; provided, however, that counsel selected by the Indemnifying Party shall be reasonably satisfactory to the Indemnified Party. The Indemnifying Party shall be liable for the fees and expenses of counsel employed by the Indemnified Party for any period during which the Indemnifying Party has not assumed the defense of any Third Party Claim (other than during any period during which the Indemnified Party has failed to give notice of such Third Party Claim as provided above). If the Indemnifying Party shall assume the defense of the Third Party Claim, then the Indemnifying Party shall not compromise or settle such Third Party Claim without the prior written consent of the Indemnified Party, which consent shall not be unreasonably withheld, delayed or conditioned; provided, however, that the Indemnified Party shall have no obligation to consent to any settlement that (a) does not include, as an unconditional term thereof, the giving by the claimant or the plaintiff of a release of the Indemnified Party from all liability with respect to such Third Party Claim or (b) involves the imposition of equitable remedies or the imposition of any material obligations on such Indemnified Party other than financial obligations for which such Indemnified Party is indemnified hereunder. As long as the Indemnifying Party is contesting any such Third Party Claim on a timely basis, the Indemnified Party shall not pay, compromise or settle any claims brought under such Third Party Claim. Notwithstanding the assumption by the Indemnifying Party of the defense of any Third Party Claim as provided in this Section 21.3, the Indemnified Party shall be permitted to participate in the defense of such Third Party Claim and to employ counsel at its own expense (it being understood that the Indemnifying Party controls such defense); provided, however, that, if the defendants in any Third Party Claim shall include both an Indemnifying Party and any Indemnified Party, and such Indemnified Party shall have reasonably concluded that counsel selected by the Indemnifying Party has a conflict of interest because of the availability of different or additional defenses to such Indemnified Party, such Indemnified Party shall then have the right to select separate counsel to participate in the defense of such Third Party Claim on its behalf, at the expense of the Indemnifying Party; provided that the Indemnifying Party shall not be obligated to pay the expenses of more than one separate counsel for all Indemnified Parties, taken together.

Section 21.4. Defenses. If the Indemnifying Party shall fail to notify the Indemnified Party of its desire to assume the defense of any Third Party Claim within the prescribed period of time, or shall notify the Indemnified Party that it will not assume the defense of any such Third Party Claim, then the Indemnified Party may assume the defense of any such Third Party Claim, in which case it may do so acting in good faith and otherwise in such manner as it may deem appropriate, and the Indemnifying Party shall be bound by any determination made in such Third Party Claim.

Section 21.5. Cooperation. The Indemnified Party and the Indemnifying Party shall each cooperate fully (and shall each cause its Affiliates to cooperate fully) with the other in the defense of any Third Party Claim pursuant to this Article 21. Without limiting the generality of the foregoing, each such Person shall furnish the other such Person (at the expense of the Indemnifying Party) with such documentary or other evidence as is then in its or any of its Affiliates' possession, as may reasonably be requested by the other Person for the purpose of defending against any such Third Party Claim.

Section 21.6. Recovery. The amount of any indemnity hereunder shall be reduced by any insurance proceeds (including any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to the Third Party Claim) actually recovered by the Indemnified Party in connection with the Third Party Claim. If at any time subsequent to the receipt by an Indemnified Party of an indemnity payment hereunder, such Indemnified Party (or any Affiliate thereof) receives any recovery, settlement or other similar payment with respect to the Third Party Claim for which it received such indemnity payment (a "Recovery"), such Indemnified Party shall then promptly pay to the Indemnifying Party the amount of such Recovery, less any expenses incurred by such Indemnified Party (or its Affiliates) in connection with such Recovery, but in no event shall any such payment exceed the amount of such indemnity payment.

Section 21.7. Subrogation. To the extent the Indemnifying Party makes or is required to make any indemnity payment to the Indemnified Party, the Indemnifying Party shall be entitled to exercise, and shall be subrogated to, any rights and remedies (including rights of indemnity, rights of contribution and other rights of recovery) that the Indemnified Party or any of its Affiliates may have against any other Person with respect thereto, whether directly or indirectly related. The Indemnified Party shall permit the Indemnifying Party to use the name of the Indemnified Party and the names of the Indemnified Party's Affiliates in any transaction or in any proceeding or other matter involving any of such rights or remedies; and the Indemnified Party shall take such actions as the Indemnifying Party may reasonably request for the purpose of enabling the Indemnifying Party to perfect or exercise its right of subrogation hereunder.

ARTICLE 22

REPRESENTATIONS, WARRANTIES AND COVENANTS

Section 22.1. Mutual Representations and Warranties. Each Party hereby represents and warrants to the other Party that all of the statements in this Section 22.1 are true and correct as of the Execution Date (unless another date is expressly indicated) and will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) It has knowledge and experience in financial matters and in the electric industry that enable it to evaluate the merits and risks of this Agreement and the transactions contemplated hereby, and is capable of evaluating such merits and risks and assuming such risks. It is acting for its own account, has made its own independent decision to enter into this Agreement as to whether this Agreement is appropriate and proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in doing so, and understands and accepts the terms, conditions, and risks of this Agreement and the transactions contemplated hereby;

(b) It has entered into this Agreement in connection with the conduct of its business;

(c) The other Party is not acting as a fiduciary or an advisor with respect to this Agreement or the transactions contemplated hereby;

(d) It is not subject to an Insolvency Event and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it that could result in the occurrence of an Insolvency Event with respect to it; and

(e) It is an entity subject to the procedures and substantive provisions of the Bankruptcy Code applicable to U.S. corporations or limited liability companies, as applicable, generally.

Section 22.2. Additional Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Owner that all of the statements in this Section 22.2 are true and correct as of the Execution Date (unless another date is expressly indicated) and, except for the statement in Section 22.2(h), will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) Purchaser is duly organized, validly existing, and in good standing under the laws in the State of Delaware and is qualified in each other jurisdiction where the failure to so qualify would have a Material Adverse Effect on Purchaser, and Purchaser has all requisite power and authority to conduct its business, own its properties, and to execute, deliver, and perform its obligations under this Agreement;

(b) Purchaser has all requisite corporate power and authority necessary to authorize the execution and delivery of this Agreement and the performance of its obligations hereunder, and to consummate the transactions contemplated hereby, and this Agreement has been duly executed and delivered by Purchaser;

(c) Assuming due authorization, execution and delivery by Owner, this Agreement constitutes Purchaser's legal, valid and binding obligation enforceable against Purchaser in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization and other laws of general application relating to or affecting creditors' rights generally and to general principles of equity (regardless of whether considered in a proceeding in equity or at law);

(d) No legal proceeding is pending or, to its knowledge, threatened against Purchaser or any of its Affiliates that could have a Material Adverse Effect on Purchaser;

(e) No event with respect to Purchaser has occurred or is continuing that would constitute a Purchaser Default, and no Purchaser Default will occur as a result of Purchaser entering into or performing its obligations under this Agreement;

(f) The execution, delivery and performance of this Agreement by Purchaser does not and will not (i) violate any provisions of its certificate of incorporation or bylaws, or any Applicable Law; or (ii) violate, or result in any breach of, or constitute any default under, any agreement or instrument to which it is a party or by which it or any of its properties may be bound or affected;

(g) No actions, Consents, notifications, waivers, orders and filings are necessary with respect to the execution, delivery and performance of this Agreement by Purchaser; and

(h) To the best of Purchaser's knowledge, the Canadian Approvals and the Operational Approvals constitute all of the actions, Consents, notifications, waivers, orders and filings that are necessary to commence construction of the Québec Line in a manner consistent with Attachment A.

(i) Purchaser is in compliance with all Applicable Laws, except such noncompliance as could not reasonably be expected to have a Material Adverse Effect on Purchaser. Purchaser has not received any written notice that it is under investigation with respect to a violation of any Applicable Law that could reasonably be expected to have a Material Adverse Effect on Purchaser.

Section 22.3. Additional Representations and Warranties of Owner. Owner hereby represents and warrants to Purchaser that all of the statements in this Section 22.3 are true and correct as of the Execution Date (unless another date is expressly indicated) and, except for the statement in Section 22.3(g),will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) Owner is duly organized, validly existing, and in good standing under the laws in the State of New Hampshire and is qualified in each other jurisdiction where the failure to so qualify would have a Material Adverse Effect on Owner, and Owner has all requisite power and authority to conduct its business, own its properties, and to execute, deliver, and perform its obligations under this Agreement;

(b) Owner has all requisite limited liability company power and authority necessary to authorize the execution and delivery of this Agreement and the performance of its obligations hereunder, and to consummate the transactions contemplated hereby, and this Agreement has been duly executed and delivered by Owner;

(c) Assuming due authorization, execution and delivery by Purchaser, this Agreement constitutes Owner's legal, valid and binding obligation enforceable against Owner in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization and other laws of general application relating to or affecting creditors' rights generally and to general principles of equity (regardless of whether considered in a proceeding in equity or at law);

(d) No legal proceeding is pending or, to its knowledge, threatened against Owner or any of its Affiliates that could have a Material Adverse Effect on Owner;

(e) No event with respect to Owner has occurred or is continuing that would constitute an Owner Default, and no Owner Default will occur as a result of Owner entering into or performing its obligations under this Agreement;

(f) The execution, delivery and performance of this Agreement by Owner does not and will not (i) violate any provisions of its articles of organization or operating agreement, or any Applicable Law; or (ii) violate, or result in any breach of, or constitute any default under, any agreement or instrument to which it is a party or by which it or any of its properties may be bound or affected;

(g) To the best of Owner's knowledge, the Owner Approvals and the Operational Approvals constitute all of the actions, Consents, notifications, waivers, orders and filings that are necessary with respect to the execution, delivery and performance of this Agreement by Owner, other than the AC Upgrade Approvals; and

(h) Owner is in compliance with all Applicable Laws, except such noncompliance as could not reasonably be expected to have a Material Adverse Effect on Owner. Owner has not received any written notice that it is under investigation with respect to a violation of any Applicable Law that could reasonably be expected to have a Material Adverse Effect on Owner.

Section 22.4. NO OTHER REPRESENTATIONS OR WARRANTIES. THE REPRESENTATIONS AND WARRANTIES OF OWNER SET FORTH IN Section 22.1 AND Section 22.3 ARE OWNER'S SOLE REPRESENTATIONS AND WARRANTIES ASSOCIATED WITH THE NORTHERN PASS TRANSMISSION LINE AND ARE MADE IN LIEU OF ALL OTHER REPRESENTATIONS, WARRANTIES AND GUARANTEES, EXPRESS OR IMPLIED, ASSOCIATED WITH THE NORTHERN PASS TRANSMISSION LINE, INCLUDING REPRESENTATIONS OR WARRANTIES AS TO MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE. THE FOREGOING SENTENCE SHALL NOT BE CONSTRUED IN ANY WAY TO LIMIT OWNER'S EXPRESS OBLIGATIONS UNDER THIS AGREEMENT.

ARTICLE 23

TRANSFER OF INTERESTS

Section 23.1. No Transfer of Interests.

(a) Any (i) direct or indirect change of Control of either Party (whether voluntary or by operation of law), (ii) sale, transfer or other disposition of all or substantially all of the assets of either Party or (iii) except as provided in Section 23.3, assignment, transfer or other disposition of, whether to one or more assignees or transferees, all or any portion of either Party's rights, interests or obligations under this Agreement (each of the foregoing, a "Transfer"), shall require the prior written consent of the other Party, which consent shall not be unreasonably withheld, delayed or conditioned when viewed in light of all reasonable considerations, including the security or other financial assurances to be provided by on or behalf of any proposed successor or assign (including the net worth and creditworthiness of the issuer) and the availability and terms of any consent required from any Financing Party in connection with such Transfer. Any Transfer in contravention of this Article 23 shall be null and void.

(b) If Owner consents to a Transfer by Purchaser pursuant to this Section 23.1, then, upon such Transfer, including (i) the assumption, in writing by the Transferee, of Purchaser's obligations under this Agreement with respect to the Transferred portion of this Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (ii) delivery to Owner of any replacement security or other financial assurances to be provided by or on behalf of such Transferee, then, provided that a Purchaser Default shall not have occurred and be continuing, (x) the obligations of Purchaser (and of Hydro-Québec under the Purchaser Guaranty) shall terminate to the extent of the Transferred portion of this Agreement (it being understood that the Stated Cap shall be reduced in proportion to the Transferred portion of this Agreement), and Purchaser and Hydro-Québec shall be fully, finally, and unconditionally released from all liability associated therewith to the extent of the Transferred portion of this Agreement, and (y) at the request of Purchaser, Owner shall execute and deliver, to Purchaser or Hydro-Québec, a full, final, and unconditional release of the Purchaser Guaranty, in such form as Purchaser may reasonably request, with respect to the Transferred portion of this Agreement.

(c) If Purchaser consents to a Transfer by Owner pursuant to this Section 23.1, then, upon such Transfer, including (i) the assumption, in writing by the Transferee, of Owner's obligations under this Agreement with respect to the Transferred portion of this Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (ii) delivery to Purchaser of any replacement security or other financial assurances to be provided by or on behalf of such Transferee, then, provided that an Owner Default shall not have occurred and be continuing, (x) the obligations of Owner (and of Northeast Utilities and NSTAR under the Owner Guaranties and the Membership Pledges) shall terminate to the extent of the Transferred portion of this Agreement (it being understood that the aggregate liability of Northeast Utilities and NSTAR under the Owner Guaranties shall be reduced in proportion to the Transferred portion of this Agreement), and Owner, Northeast Utilities and NSTAR shall be fully, finally, and unconditionally released from all liability associated therewith to the extent of the Transferred portion of this Agreement, and (y) at the request of Owner, Purchaser shall execute and deliver, to Owner, Northeast Utilities or NSTAR, a full, final, and unconditional release of the Owner Guaranties and the Membership Pledges, in such form as Owner may reasonably request, with respect to the Transferred portion of this Agreement. For the avoidance of doubt, neither the Purchaser Mortgage nor the Security

Agreement shall not terminate upon any Transfer by Owner pursuant to this Section 23.1, unless otherwise agreed in writing by Purchaser.

Section 23.2. Exceptions. Notwithstanding Section 23.1, consent shall not be required for any of the following:

(a) Any (i) change of Control of Owner or (ii) transfer or other disposition of all or substantially all of the assets of Owner, in each case, resulting from a collateral assignment in favor of a Financing Party in accordance with Section 23.3;

(b) Any change of Control of Owner resulting from the direct or indirect transfer of interests in Northeast Utilities or NSTAR; or

(c) Any change of Control of Purchaser resulting from the direct or indirect transfer of interests in Hydro-Québec.

Section 23.3. Collateral Assignment. Owner shall be entitled, without restriction, to make one or more assignments of this Agreement for purposes of collateral security or any or all of its rights and benefits hereunder to or for the benefit of any and all Financing Parties, or grant to or for the benefit of any and all Financing Parties a lien on, or security interest in, any right, title or interest in all or any part of Owner's rights hereunder for the purpose of the financing or successive refinancing of the ownership, development, engineering, construction or operation of the Northern Pass Transmission Line; provided, however, that such assignment for purposes of collateral security shall recognize Purchaser's rights under this Agreement on terms and conditions as may be customary for financings of a similar nature and reasonably requested by any Financing Party. To facilitate Owner's obtaining of financing or successive refinancing for the ownership, development, engineering, construction or operation of the Northern Pass Transmission Line, Purchaser shall cooperate with Owner and shall execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party. Purchaser shall also, at Owner's request, cause Hydro-Québec to cooperate with Owner to execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party.

ARTICLE 24

MISCELLANEOUS

Section 24.1. Governing Law. This Agreement and each of its provisions shall be governed by, and construed in accordance with, the laws of the State of New York without reference to its conflict of law rules other than Section 5-1401 of the New York General Obligations Law.

Section 24.2. Entire Agreement. This Agreement, together with the Attachments, constitutes the entire agreement and understanding among the Parties with respect to all subjects covered hereby and thereby and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

Section 24.3. Severability. Except as otherwise provided in Section 2.2, (a) in the event any part of this Agreement is held to be illegal, invalid or unenforceable to any extent, the legality, validity and enforceability of the remainder of this Agreement shall not be affected thereby, and shall remain in full force and effect and shall be enforced to the greatest extent permitted by Applicable Law and (b) with respect to any provision found to be illegal, invalid or unenforceable by an arbitrator having jurisdiction, the Parties shall endeavor to replace such invalid, illegal or unenforceable provision with the valid, legal and enforceable provision that achieves, as nearly as practicable, the commercial intent of this Agreement (as it may be amended from time to time).

Section 24.4. Notices. All notices, billings, requests, demands, waivers, consents and other communications under this Agreement shall be in writing and shall be effective (a) upon personal delivery thereof, including by overnight mail or courier service, with a record of receipt, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon the fourth (4th) day after mailing, (c) in the case of notice by facsimile for any communications other than billings, upon transmission; provided that such facsimile transmission is promptly confirmed by either of the methods set forth in the foregoing clause (a) or (b), in each case, addressed to each Party and copy party hereto at its address set forth below or at such other address as a Party may from time to time designate by written notice to the other Party pursuant to this Section 24.4, (d) in the case of notice by facsimile for billings only (but not any other communication, including any subsequent demand notice for any unpaid amounts), upon receipt of confirmation of successful transmission, but without any further requirement for evidence of receipt or confirmation by either of the methods set forth in the foregoing clause (a) or (b), or (e) in the case of notice by electronic mail for billings only (but not any other communication, including any subsequent demand notice for any unpaid amounts), upon transmission, without any requirement for evidence of receipt or confirmation by either of the methods set forth in the foregoing clause (a) or (b); provided that the Party delivering such notice did not receive any notice of unsuccessful or delayed transmission. A notice given in connection with this Section 24.4 but received on a day other than a Business Day, or after business hours in the situs of receipt, shall be deemed to be received on the next Business Day.

If to Owner:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: James A. Muntz, President
107 Selden Street
Berlin, Connecticut 06037
United States of America
Facsimile: (860)665-6717
Email: james.muntz@nu.com

With a copy to:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: Senior Vice President and General Counsel

56 Prospect Street
Hartford, Connecticut 06103
United States of America
Facsimile: (860)728-4581
Email: gregory.butler@nu.com

For billing purposes only:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: Director – Transmission Rates
107 Selden Street
Berlin, Connecticut 06037
United States of America
Facsimile: (860)665-2805
Email: lisa.cooper@nu.com

If to Purchaser:

Hydro Renewable Energy Inc.
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Attention: Maxime Lanctôt, President
Facsimile: (514)289-6723
Email: lanctot.maxime@hydro.qc.ca

For billing purposes only:

Hydro Renewable Energy Inc.
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Attention: Hélène Létourneau, Billing Manager
Facsimile: (514)289-6867
Email: letourneau.helene@hydro.qc.ca

Section 24.5. Waiver; Cumulative Remedies. Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but such waiver shall not be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be, or construed as, a subsequent waiver of, or estoppel with respect to, the same or any other term or by Applicable Law. Except as otherwise provided in Section 14.3(b), the failure of or delay on the part of either Party to enforce or insist upon compliance with or strict performance of any term or condition of this Agreement, or to take advantage of any of its rights thereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect. Except as otherwise provided herein, the remedies provided in this Agreement are cumulative and not exclusive of any remedies provided by law or in equity.

Section 24.6. Confidential Information. Each Party hereby agrees that it shall not disclose, or cause to be disclosed, to third parties any Confidential Information with respect to the other Party or any material or information identified as Critical Energy Infrastructure Information (other than to a disclosing Party's Affiliates and its and their respective counsel, directors, officers, employees, lenders, advisors or consultants, in each case, who have a need to know such information and have agreed to keep such information confidential). Each Party shall be responsible for ensuring that any Person to whom it discloses any Confidential Information shall comply with the restrictions in this Section 24.6. The restrictions in this Section 24.6 shall not apply (w) to the extent disclosure is required by Applicable Law or the requirements of a Governmental Authority, (x) to the extent reasonably deemed by the disclosing Party to be required or desirable in connection with regulatory proceedings (including proceedings relating to FERC or any other national, federal, provincial, state or regulatory agency), (y) to the extent reasonably deemed by the disclosing Party to be required to be disclosed in connection with a Dispute between the Parties, or the defense of any litigation or dispute, or (z) as approved for release or disclosure by the other Party. In the event disclosure is made pursuant to this Section 24.6, the disclosing Party shall use reasonable efforts to minimize the scope of any disclosure and advise recipients of the confidentiality restrictions provided herein. Notwithstanding the foregoing, this Section 24.6 shall not apply to the following information:

(a) Information that is a matter of public knowledge at the time of its disclosure or is thereafter published in or otherwise ascertainable from a source available to the public without breach of this Section 24.6;

(b) Information that is obtained from a Person other than by or as a result of unauthorized disclosure; or

(c) Information that, prior to the time of disclosure, had been independently developed or obtained by the disclosing Party or its Affiliates independent of information obtained as a result of unauthorized disclosure.

Section 24.7. No Third-Party Rights. Except for any Financing Parties contemplated by Section 23.3 and any Owner Indemnified Party or Purchaser Indemnified Party contemplated by Article 21, the Parties do not intend for this Agreement to confer a third-party beneficiary status or rights of action upon any Person whatsoever other than the Parties and their permitted successors and assigns, and nothing contained herein, either express or implied, shall be construed to confer upon any Person, other than the Parties and their permitted successors and assigns, any rights of action or remedies under this Agreement or in any manner, or any duty, standard of care, or liability with respect thereto. This Agreement does not create third-party rights.

Section 24.8. Permitted Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of each of the Parties and their successors, legal representatives and assigns.

Section 24.9. Relationship of the Parties. This Agreement shall not be construed as creating an association, joint venture, trust or partnership between the Parties or as imposing any partnership obligation or liability upon either Party. Except as contemplated by Article 10 or Section 15.3(b), neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

Section 24.10. Construction. No presumption shall operate in favor of or against either Party as a result of any responsibility for drafting this Agreement.

Section 24.11. Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Parties acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

Section 24.12. Survival. The provisions of Section 3.3, Section 3.4, Section 3.5, Section 3.6, Article 9, Article 13 (if and to the extent required for purposes of determining the Decommissioning Plan and Decommissioning Estimate, as provided in Section 9.3), Article 14, Article 15, Section 17.2.1, Article 18, Article 19, Article 20, Article 21 and this Article 24 shall survive the expiration or earlier termination of this Agreement.

Section 24.13. Language. All notices, requests, demands, waivers, consents and other communications between Owner and Purchaser under this Agreement shall be conducted in English.

Section 24.14. Headings and Table of Contents. The headings of the articles and sections of this Agreement and the Table of Contents are inserted for purposes of convenience only, and shall not be construed to affect the meaning or construction of any of the provisions hereof.

Section 24.15. Waiver of Immunities. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereby constitute a commercial transaction. To the extent a Party (including any assignees of a Party's rights or obligations under this Agreement) may be entitled, in any jurisdiction, to claim for itself, or any of its assets, revenues or properties, sovereign or other immunity, as the case may be, from service of process, suit, the jurisdiction of any court or arbitral tribunal, attachment (whether in aid of execution or otherwise) or enforcement of a judgment (interlocutory or final) or award or any other legal process in a matter arising out of or relating to this Agreement, each Party agrees not to claim or assert, and hereby waives, such immunity. Without limiting the generality of the foregoing, each Party agrees that the waivers set forth in this Section 24.15 shall have the fullest scope permitted under the Immunities Act and under any other Applicable Law related to sovereign immunity.

[*Remainder of Page Intentionally Left Blank*]

IN WITNESS WHEREOF, Owner and Purchaser have executed this Agreement as of the Execution Date.

OWNER:

NORTHERN PASS TRANSMISSION LLC

By: ____________________________________
Name: ____________________________________
Title: ____________________________________

PURCHASER:

HYDRO RENEWABLE ENERGY INC. (f/k/a H.Q. HYDRO RENEWABLE ENERGY, INC.)

By: ____________________________________
Name: ____________________________________
Title: ____________________________________

ATTACHMENT A

HVDC Transmission Project

I. Technical Design of the Northern Pass Transmission Line

1. HVDC Line:

- Transmission Line Voltage Level: +/-300 kV
- Approximate Length: 140 miles
- Transmission Line Construction: Overhead line
- Connections/Terminuses: The northern terminus of the HVDC Line will interconnect with the Québec Line at the U.S. Border. The southern terminus of the HVDC Line will be at the DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire.

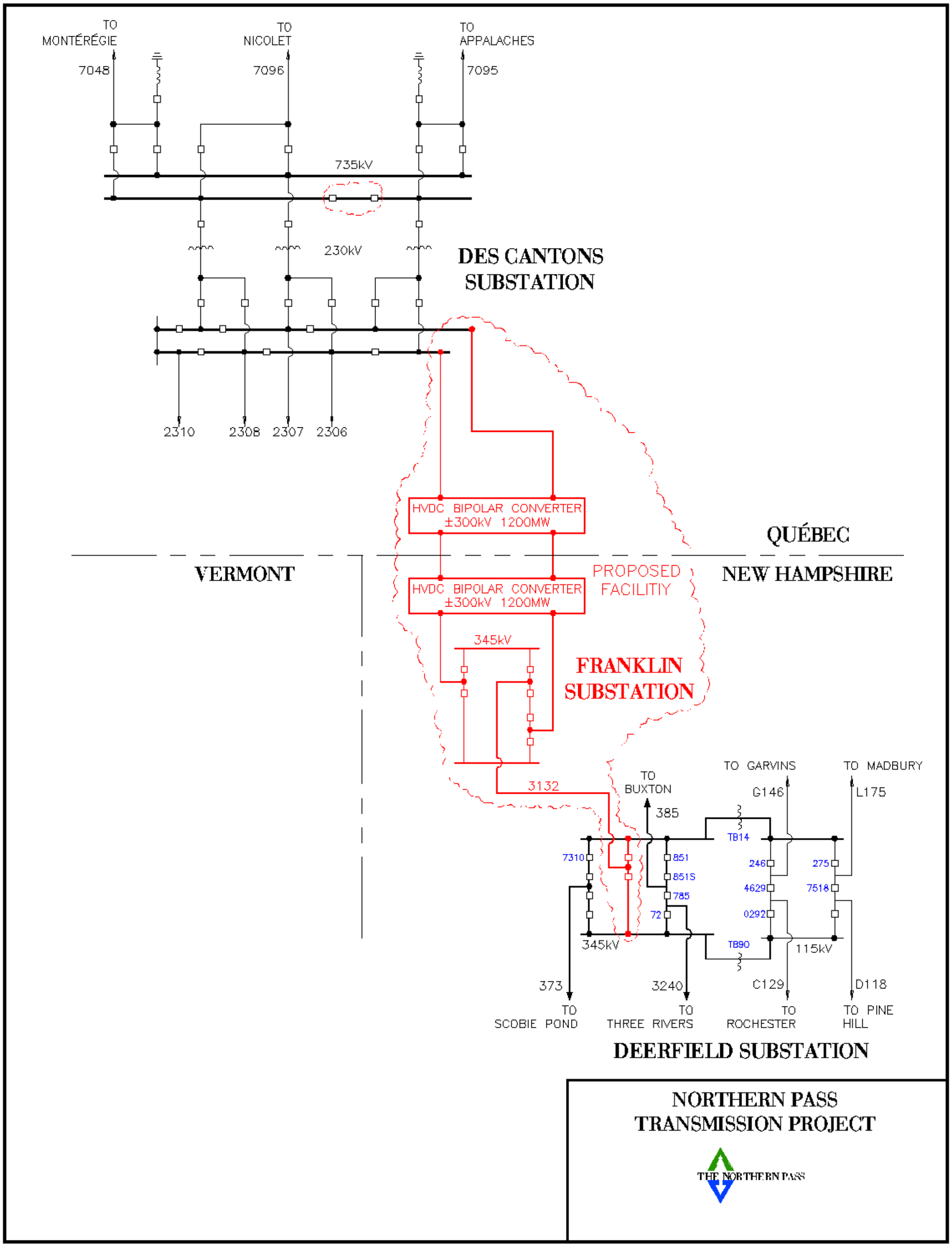
2. AC Line:

- Transmission Line Voltage Level: 345 kV
- Approximate Length: 43 miles
- Transmission Line Construction: Overhead line
- Connections/Terminuses: The northern terminus of the AC Line will be at the Franklin substation at the DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire. The southern terminus of the AC Line will be at the Deerfield substation in the State of New Hampshire.

3. DC/AC Converter Station:

- The DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire will be designed and constructed in accordance with the Design Capability in order to support bidirectional DC power flows over the Northern Pass Transmission Line to and from the 345 kV AC transmission system operated by ISO-NE.

II. One-Line Diagram of the HVDC Transmission Project



ATTACHMENT B

Formula Rate Sheet

I. Methodology

This formula sets forth the method that Owner shall use to determine its Revenue Requirement for the Northern Pass Transmission Line and AC Upgrades under the Transmission Service Agreement, dated as of October 4, 2010, and is subject to all of the terms and conditions of such Agreement.

The Revenue Requirement under the Agreement shall be derived through an annual Formula Rate calculation effective for the first Contract Year and each subsequent Contract Year based upon the estimated costs of the Northern Pass Transmission Line and the AC Upgrades. An annual true-up shall be performed by recalculation of the estimated costs for the first Contract Year and each subsequent Contract Year based upon actual cost information as reported in Owner's FERC Form 1 for that year or as set forth in Owner's books and records.

II. Definitions

Capitalized terms not otherwise defined elsewhere in the Agreement and as used in this Attachment B have the following definitions:

- *Administrative and General Expense* will equal Owner's expenses, as recorded in FERC Account Nos. 920 – 935, excluding FERC Account Nos. 924, 928 and 930.1.

- *Amortization of Investment Tax Credits* will equal Owner's credits, as recorded in FERC Account No. 411.4.

- *Amortization of Regulatory Asset – Pre-COD Expenses* will equal the total amortization expense related to those costs incurred by Owner before the Commercial Operation Date that are not included in FERC Account No. 107 – Construction Work in Progress (including the costs associated with AC Upgrades that are placed in service before the Commercial Operation Date), plus the Carrying Charges on these amounts from the date such costs are incurred until the Commercial Operation Date, as recorded in the appropriate FERC Account.

- *Asset Retirement Obligation (Decommissioning)* will equal the asset retirement cost for transmission plant recorded in FERC Account No. 359.1 and the asset retirement obligation recorded in FERC Account No. 230.

- *Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant* will equal Owner's transmission plant, general plant, and intangible plant depreciation expense as recorded in FERC Account No. 403. The annual depreciation expense for an asset comprising part of the Northern Pass Transmission Line as of the Commercial Operation Date will be computed using the depreciable life of the asset, as defined in Section 8.2 of the Agreement. Depreciation will begin on the in-service date of the Northern Pass Transmission Line. An asset comprising part of a capital addition that is placed-in-service after the Commercial Operation Date will be depreciated, for ratemaking purposes, using the depreciable life of the asset, as defined in Section 8.2 of the Agreement. For any asset that is retired prior to the lesser of its depreciable life, as defined in Section 8.2 of the Agreement, or the completion of forty (40) years from the Commercial Operation Date, the remaining net book value and cost of removal for such asset will be collected over the then-remaining contract life through a recalculation of the depreciation rate applied to the remaining plant balance and reflecting the retirement of the asset. Such Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant will exclude Depreciation Expense associated with Asset Retirement Obligation (Decommissioning).

- *Depreciation Expense associated with Asset Retirement Obligation (Decommissioning)* will equal Owner's depreciation expense, as recorded in FERC Account No. 403, specifically related to Asset Retirement Obligation (Decommissioning).

- *Depreciation Reserve for Transmission Plant, General Plant, and Intangible Plant* will equal the Owner's reserve balance associated with Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant, as recorded in FERC Account No. 108. Such Depreciation Reserve for Transmission Plant, General Plant, and Intangible Plant will exclude Depreciation Reserve associated with Asset Retirement Obligation (Decommissioning).

- *Depreciation Reserve associated with Asset Retirement Obligation (Decommissioning)* will equal Owner's reserve balance related to Depreciation Expense associated with Asset Retirement Obligation (Decommissioning), as recorded in FERC Account No. 108.

- *General Plant* will equal Owner's gross plant balance, as recorded in FERC Account Nos. 389 – 399.

- *Insurance Cost* will equal Owner's expenses, as recorded in FERC Account No. 924.

- *Intangible Plant* will equal Owner's intangible plant balance, as recorded in FERC Accounts Nos. 301 – 303.

- *Levelized Annual Decommissioning Payment* will equal the sum of the Levelized Monthly Decommissioning Payments that Section 9.3.3(a) of the Agreement specifies be included in the Formula Rate for the applicable Contract Year, unless a separate rate is established for the recovery of Net Decommissioning Costs pursuant to Section 9.3.1(c) of the Agreement.

- *Miscellaneous Revenues (such as Rents Received from Electric Property)* will equal Owner's revenues, as recorded in FERC Account Nos. 454 and 456.1, excluding the revenues received by Owner from Purchaser under the Agreement. This includes revenue received by Owner from third parties for their use of Owner's real or personal property associated with the Northern Pass Transmission Line that is recorded in FERC Account No. 454, and revenue received by Owner from third parties for resales of Firm Transmission Service and non-firm Additional Transmission Service over the Northern Pass Transmission Line that is recorded in FERC Account No. 456.1.

- *Operation and Maintenance Expense* will equal Owner's expenses, as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562 – 564, 566, and 568 – 576.5.

- *Payroll Taxes* will equal those payroll expenses, as recorded in Owner's FERC Account Nos. 408.1 and 409.1.

- *Plant Held for Future Use* will equal Owner's balance in FERC Account No. 105.

- *Plant Materials and Supplies* will equal the Owner's balance, as recorded in FERC Account No. 154.

- *Prepayments* will equal Owner's prepayment balance, as recorded in FERC Account No. 165.

- *Regulatory Asset – Asset Retirement Obligation (Decommissioning)* will equal the total amounts recorded in a subaccount within FERC Account No. 182 for the Net Decommissioning Costs.

- *Regulatory Asset – Pre-COD Expenses* will equal the total costs incurred by Owner before the Commercial Operation Date that are not included in FERC Account No. 107 – Construction Work in Progress (including the costs associated with AC Upgrades that are placed in service before the Commercial Operation Date), plus the Carrying Charges on these amounts (calculated using Owner's weighted cost of capital, based upon the Weighted Cost of Equity (as determined under <u>Section III.A.2.</u> below) and the Owner's Weighted Cost of Long-term Debt (as determined under <u>Section III.B.</u> below)) from the date such costs are incurred until the Commercial Operation Date. Such costs will be included in a subaccount within FERC Account No. 182. This account will be amortized over a three (3)-year period beginning on the Commercial Operation Date.

- *Right-of-Way (Rental) Expense* will equal Owner's expense, as recorded in FERC Account No. 567.

- *Scheduling, System Control and Dispatch Service Expense* will equal Owner's expense, as recorded in FERC Account Nos. 561.1 – 561.4.

- *Total Accumulated Deferred Income Taxes* will equal the net of Owner's deferred tax balances, as recorded in FERC Account Nos. 281 – 283 and Owner's deferred tax balances, as recorded in FERC Account No. 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FAS 109. Such

Total Accumulated Deferred Income Taxes will exclude any deferred income tax amounts associated with the Asset Retirement Obligation (Decommissioning) and the Regulatory Asset – Asset Retirement Obligation (Decommissioning).

- *Total Municipal Tax* will equal Owner's expenses, as recorded in FERC Account Nos. 408.1 and 409.1.
- *Transmission Plant* will equal Owner's gross plant balance, as recorded in FERC Account Nos. 350 – 359. Such Transmission Plant will exclude any amounts recorded in FERC Account No. 359.1.
- *Transmission Support Expense* will equal Owner's expenses, as recorded in FERC Account No. 565.

III. Calculation of Revenue Requirement

The Revenue Requirement for the Northern Pass Transmission Line and AC Upgrades will equal the sum of the following Owner components:

(A) Return on Equity

(B) Return on Long-term Debt

(C) Federal Income Taxes associated with Return on Equity

(D) State Income Taxes associated with Return on Equity

(E) Depreciation Expense

(F) Amortization of Investment Tax Credits

(G) Municipal Tax Expense

(H) Payroll Tax Expense

(I) Operation and Maintenance Expense

(J) Transmission Administrative and General Expense

(K) Taxes and Fees Charge

(L) Right-of-Way (Rental) Expense

(M) Scheduling, System Control and Dispatch Service Expense

(N) Amortization of Regulatory Asset – Pre-COD Expenses

(O) Levelized Annual Decommissioning Payment

(P) Transmission Support Expense

(Q) Miscellaneous Revenues (such as Rents Received from Electric Property)

A. *Return on Equity* will equal the product of the Transmission Investment Base ("Rate Base") (as determined under Section III.A.1. below) and the Weighted Cost of Equity (as determined under Section III.A.2. below).

1. Transmission Investment Base

The Rate Base will consist of items (i) through (x) below. The average balance (beginning and end of year) will be used to calculate each of these items.

(i) Transmission Plant, plus

(ii) General Plant, plus

(iii) Intangible Plant, plus

(iv) Plant Held for Future Use, less

(v) Depreciation Reserve, less

(vi) Accumulated Deferred Income Taxes, plus

(vii) Regulatory Asset – Pre-COD Expenses, plus

(viii) Prepayments, plus

(ix) Plant Materials and Supplies, plus

(x) Cash Working Capital

Definitions of Rate Base Items:

(i) *Transmission Plant* will equal the balance of Owner's investment in Transmission Plant.

(ii) *General Plant* will equal Owner's balance of investment in General Plant.

(iii) *Intangible Plant* will equal Owner's balance of investment in Intangible Plant.

(iv) *Plant Held for Future Use* will equal the balance of Owner's Plant Held for Future Use.

(v) *Depreciation Reserve* will equal Owner's Depreciation Reserve for Transmission Plant, General Plant and Intangible Plant.

(vi) *Accumulated Deferred Income Taxes* will equal Owner's balance of Total Accumulated Deferred Income Taxes.

(vii) *Regulatory Asset – Pre-COD Expenses* will equal Owner's balance of Regulatory Asset – Pre-COD Expenses.

(viii) *Prepayments* will equal Owner's electric balance of Prepayments.

(ix) *Plant Materials and Supplies* will equal Owner's balance of Plant Materials and Supplies.

(x) *Cash Working Capital* will be a twelve and one half percent (12.5%) allowance (forty-five (45) days divided by three hundred sixty (360) days) of Operation and Maintenance Expense, Administrative and General Expense, and Transmission Support Expense.

2. The Weighted Cost of Equity will be calculated based upon an assumed capital structure of 50% equity throughout the Term of the Agreement, and will equal the product of:

(a) ROE, as set forth in Section 8.4 of the Agreement, and

(b) Assumed equity ratio of 50%.

B. *Return on Long-term Debt* will equal the product of Rate Base (as determined in Section III.A.1. above) and Owner's Weighted Cost of Long-term Debt. Owner's Weighted Cost of Long-term Debt will equal the product of:

(a) Owner's weighted average embedded cost to maturity (adjusted to reflect any (i) premiums, (ii) discounts, (iii) issuances expenses, and (iv) losses and gains on reacquired debt) of Owner's long-term debt then outstanding, calculated using a beginning and end of the year average, and

(b) Assumed debt ratio of 50% throughout the Term of the Agreement.

C. *Federal Income Taxes associated with Return on Equity* will equal the product of:

(a) $$\frac{(A + ((B + C) / D)) \times FT}{1 - FT}$$

where A is the Return on Equity (as determined in Section III.A. above), B is Amortization of Investment Tax Credits (as determined in Section III.F. below), C is the equity component of AFUDC included in the Depreciation Expense (as determined in Section III.E. below), D is Rate Base (as determined in Section III.A.1. above) and FT is the statutory Federal Income Tax Rate levied by the Federal Government for Income Taxes, and

(b) Rate Base (as determined in Section III.A.1. above).

D. *State Income Taxes associated with Return on Equity* will equal the product of:

(a) $$\frac{(A + ((B + C) / D) + \text{Federal Income Tax Rate above}) \times ST}{1 - ST}$$

where A is the Return on Equity (as determined in Section III.A. above), B is Amortization of Investment Tax Credits (as determined in Section III.F. below), C is the equity component of AFUDC included in the Depreciation Expense (as determined in Section III.E. below), D is Rate Base (as determined in Section III.A.1. above) and ST is the statutory State(s) Income Tax Rate(s) levied by the State Government(s) for Income Taxes, and

(b) Rate Base (as determined in Section III.A.1. above).

E. *Depreciation Expense* will equal Owner's Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant.

F. *Amortization of Investment Tax Credits* will equal Owner's electric Amortization of Investment Tax Credits.

G. *Municipal Tax Expense* will equal Owner's electric Total Municipal Tax expense.

H. *Payroll Tax Expense* will equal Owner's electric Payroll Tax expense.

I. *Operation and Maintenance Expense* will equal Owner's Operation and Maintenance Expenses.

J. *Transmission Administrative and General Expenses* will equal the sum of Owner's (a) Administrative and General Expense, (b) Insurance Cost, (c) Expenses included in FERC Account No. 928 related to FERC Assessments, (d) any other Federal and State transmission-related expenses or assessments in FERC Account No. 928 and (e) specific transmission-related expenses included in FERC Account No. 930.1.

K. *Taxes and Fees Charge* will include any fee or assessment imposed by any Governmental Authority on service provided by Owner under the Agreement other than Income Taxes, Total Municipal Taxes, and Payroll Taxes.

L. *Right-of-Way (Rental) Expense* will equal the expense paid by Owner for right-of-way access.

M. *Scheduling, System Control and Dispatch Service Expense* will equal the expenses for scheduling, system control and dispatch services incurred by Owner, as recorded in Owner's FERC Form 1, Account Nos. 561.1 – 561.4.

N. *Amortization of Regulatory Asset – Pre-COD Expenses* will equal Owner's amortization expense associated with those costs recorded to the Regulatory Asset – Pre-COD Expenses account.

O. *Levelized Annual Decommissioning Payment* will equal the Levelized Annual Decommissioning Payment.

P. *Transmission Support Expense* will equal the expenses incurred and paid by Owner for transmission support, net of any associated revenues or refunds received from third parties.

Q. *Miscellaneous Revenues (such as Rents Received from Electric Property)* will equal Owner's Miscellaneous Revenues.

IV. Future Revisions to FERC Uniform System of Accounts (USA) and FERC Form 1 Requirements

If FERC prescribes an addition, deletion, or modification ("Revision") to an account in its Uniform System of Accounts (USA) and/or to its designation or description of an item in its FERC Form 1 and the Revision affects the revenue recovery under this Formula Rate described in this Schedule, Owner will use cost information from the revised USA and/or FERC Form 1 that is equivalent to the pre-Revision information in its application of the Formula Rate so that the Formula Rate's recovery of costs is unaffected by the Revision.

ATTACHMENT C

List of Owner Approvals

Set forth below are, to the best of Owner's knowledge, the Owner Approvals. The Owner Approvals do not include the AC Upgrade Approvals. Additional Governmental Approvals may be required as a result of (1) Applicable Laws that may come into effect after the Execution Date or (2) new and unexpected developments in the regulatory processes to be undertaken by Owner and its Affiliates in connection with the Northern Pass Transmission Line.

I. Construction Authorizations

1. U.S. Federal

Agency	Statute/Description
FERC	• Federal Power Act, Section 204 approval of Owner's ability to incur short term debt
FERC	• Federal Power Act, Section 205 approval of Transmission Service Agreement
FERC	• Federal Power Act, Section 205 approval of Facilities Agreement(s)
FERC	• Federal Power Act, Section 205 approval of Interconnection Agreements
U.S. Department of Energy ("DOE")	• Presidential Permit • Lead federal agency for development of an Environmental Impact Statement ("EIS") pursuant to the requirements of the National Environmental Policy Act ("NEPA") • DOE is responsible for developing the EIS that will be used by all U.S. federal agencies to fulfill the requirements of NEPA (the "NEPA/EIS development process") as those agencies process the U.S. federal permit applications for the Northern Pass Transmission Line
U.S. Forest Service ("USFS")	• Special Use Permit(s) for the Northern Pass Transmission Line to cross White Mountain National Forest (encompasses authorization to cross Appalachian Trail under the National Park Service's delegation of authority to USFS) • Modification to PSNH's existing Special Use Permits (WMNF) • Cooperating agency to NEPA/EIS development process
U.S. Army Corps of Engineers, New England District	• Permit issued under the Clean Water Act, codified at 33 U.S.C. § 1344 (§ 404 of the Clean Water Act) (Section 404 Permit) • Permit for applicable river crossings issued under Rivers and Harbors Act, 33 U.S.C. 403 § 10 • Cooperating agency to NEPA/EIS development process
U.S. Federal Aviation Administration	• Approval of structures taller than 200 feet and for construction of facilities near airports
U.S. Environmental	• Clean Water Act, 33 U.S.C. § 1251 et seq., Construction General

Agency	Statute/Description
Protection Agency	Permit (for discharge of construction-related stormwater)

2. Regional

Agency	Statute/Description
ISO-NE	• I.3.9 Project Technical Approval

3. State (New Hampshire) – Site Evaluation Committee

Agency	Statute/Description
New Hampshire Site Evaluation Committee ("SEC")	• Owner Siting Approvals • SEC Certificate (NH RSA Ch. 162-H)
New Hampshire Department of Environmental Services	• Section 401 Water Quality Certification (§ 401 of Clean Water Act) • Shoreland Protection Permit (if within 150 feet of ponds, lakes and other jurisdictional waters) (NH RSA Ch. 483-B) • Alteration of Terrain Permit (NH RSA Ch. 485-A) • Temporary and Permanent Groundwater Discharge Permit (NH RSA Ch. 485-A) • Wetlands Permits (NH RSA Ch. 482-A) • On Site Stump Disposal (No permit required per NH RSA § 149-M:4, XXII)
New Hampshire Public Utility Commission ("PUC")	• Approve Owner to commence business as a New Hampshire public utility (NH RSA § 374:22) • Approval of Owner's ability to issue short- and long-term securities (NH RSA §§ 369:1, 7) • Approval of Owner's condemnation of all land rights needed to create transmission right-of-way and to acquire other properties necessary to construct, operate and maintain the project facilities (post-siting approvals) (NH RSA § 371:1) • Approval of PSNH conveyance of Right-of-Way (ROW)/property to Owner (post-siting approvals, but pre-construction) (NH RSA § 374:30)
New Hampshire Department of Revenue and New Hampshire Division of Forests and Lands	• Notice of Intent to Cut (NH RSA § 79:10)
New Hampshire Department of Transportation	• Permit to Excavate in Roadways (NH RSA § 236:9)
New Hampshire Department of Transportation/PUC	• Authorization to cross public highways, rivers, and railroads

II. All Other Owner Approvals

1. U.S. Federal

Agency	Statute/Description
FERC	Federal Power Act, Section 205 Approval of Transmission Operating Agreement
FERC	Federal Power Act, Section 205 Approval of ISO-NE Open Access Transmission Tariff changes (as applicable)
FERC	Federal Power Act, Section 205 approval of Scheduling and Dispatch Services Agreement between Owner and PSNH for PSNH's Electric System Control Center

2. Regional (ISO-NE)

Agency	Statute/Description
ISO-NE	Acceptance of AC Upgrades for interconnection and energization to the New England Transmission System
ISO-NE	Acceptance of Northern Pass Transmission Line for interconnection and energization to the New England Transmission System

3. State (New Hampshire)

Agency	Statute/Description
PUC	Approval of Owner's ability to issue long-term securities (NH RSA § 369:1)

ATTACHMENT D

List of Canadian Approvals

Set forth below are, to the best of Purchaser's knowledge, the Canadian Approvals. Additional Governmental Approvals may be required as a result of (1) Applicable Laws that may come into effect after the Execution Date or (2) new and unexpected developments in the regulatory processes to be undertaken by Purchaser and its Affiliates in connection with the Québec Line.

- Permit or certificate, as the case may be, from the National Energy Board to construct or operate an international power line pursuant to the National Energy Board Act (R.S.C., 1985,c. N-7)

- Authorization of the Régie de l'énergie (Québec Energy Board) to acquire or construct immovables or assets for transmission purposes pursuant to An Act respecting the Régie de l'énergie (R.S.Q., chapter R-6.01)

- Certificate of authorization issued by the Government of Québec for the realization of the construction or relocation of an electric power transmission line of 315 kV or more over a distance of more than 2 km and the construction or relocation of a control and transformer station of 315 kV or more pursuant to the Environment Quality Act (R.S.Q., chapter Q-2)

- Authorization of the "Commission de protection du territoire agricole du Québec" to use a lot for any purpose other than agriculture pursuant to An Act respecting the preservation of agricultural land and agricultural activities (R.S.Q., chapter P-41.1)

- Assessment of conformity consistent with the objectives of the land use and development plan of each regional county municipality or municipality where an intervention is planned by Hydro-Québec pursuant to An Act respecting land use planning and development (R.S.Q., chapter A-19.1) (the "Land Use Planning Act") and the Order in council 554-81

- Certificate pursuant to the Regulation respecting the application of the Environment Quality Act (c. Q-2, r. 1.001) issued by the clerk or the secretary-treasurer of each local municipality affected by the project or, in the case of an unorganized territory, of each regional county municipality affected by the project attesting that the project does not contravene any municipal bylaw

- Expropriation Order in council, if required, to acquire by expropriation any immovable, servitude or construction required for the transmission of power pursuant to Hydro-Québec Act (R.S.Q., chapter H-5) and the Expropriation Act (R.S.Q., chapter E-24)

- Authorization from the International Boundary Commission to cross the Canada-U.S. border pursuant to Article 5 of the International Boundary Commission Act

- Approval, if required, by ISO-NE of Québec Line siting

ATTACHMENT E-1

Form of Purchaser Guaranty

Please see the attached.

Hydro-Québec
75, boulevard René-Lévesque ouest
5ième étage
Montréal, Québec, Canada
H2Z 1A4

GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of _______________ ___, 2010, is made and entered into by **Hydro-Québec**, a body politic and corporate, duly incorporated and regulated by Hydro-Québec Act (R.S.Q., chapter H-5) and having its head office and principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Guarantor"), in favor of **Northern Pass Transmission LLC**, a limited liability company organized and existing under the laws of the State of New Hampshire and having its principal place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **H.Q. Hydro Renewable Energy, Inc.**, a corporation created under the laws of the State of Delaware and having its place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as "HQSub"), an indirectly owned subsidiary of the Guarantor, have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of HQSub under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. Guaranty.

(a) Guaranteed Obligations. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by HQSub to the Beneficiary under the Agreement (excluding HQSub's obligation to pay Net Decommissioning Costs, but including payment of HQSub's indemnification obligations, other than as may relate to Net Decommissioning Costs), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that HQSub has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; provided, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed **[*** U.S. Dollars (U.S. $***)]** (the "Stated Cap"), plus (ii) payment of all Decommissioning Liquidated Damages, as provided in Section 1(b) of this Guaranty, plus (iii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Construction Phase shall have commenced under the Agreement; provided, further, that, subject to Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Net Decommissioning Costs.

(i) The Guarantor's obligations under Section 1(a)(ii) of this Guaranty shall be limited to the payment of (A) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions in the Agreement in the event of an Impasse with respect thereto) (which estimated Net Decommissioning Costs, solely for the purpose of calculating the Decommissioning Liquidated Damages, shall be expressed in dollars as of the date on which the Agreement is terminated as if the Decommissioning were to commence as of such date), less (B) the balance, if any, in the Decommissioning Fund as of the date of the Beneficiary's written demand under Section 1(b)(ii) of this Guaranty (net of any portion of such balance that is required to be restored to HQSub pursuant to the Bankruptcy Code or any other Insolvency Laws) (such amount, the "Decommissioning Liquidated Damages"); provided, that, if a Subsequent Use occurs, then the Guarantor's obligations under Section 1(a)(ii) of this Guaranty and this Section 1(b) shall be subject to the provisions of Section 9.3.4 of the Agreement.

(ii) The Decommissioning Liquidated Damages shall be payable by the Guarantor to the Beneficiary within thirty (30) days after receipt by the Guarantor from the Beneficiary of (A) a written demand by the Beneficiary upon the Guarantor stating that a Purchaser Default under Section 15.1(a) of the Agreement has occurred and is continuing with respect to HQSub's obligation to pay Net Decommissioning Costs pursuant to Section 9.3.3 of the Agreement (including the Levelized Monthly Decommissioning Payment and/or the Preliminary Monthly Decommissioning Payment included in the Formula Rate pursuant to Section 9.3.3(a) of the Agreement and/or the Decommissioning Estimate), (B) a certificate of the Beneficiary certifying that the Beneficiary has received all Governmental Approvals required under Applicable Law and all other consents and approvals as otherwise may be required, in each case, to commence such Decommissioning in accordance with the Decommissioning Plan, and that there are no other conditions to the undertaking of such Decommissioning, other than the payment of Decommissioning Liquidated Damages as provided herein, and (C) an irrevocable written commitment to commence to Decommission the Northern Pass Transmission Line not later than the date that is ninety (90) days after the Beneficiary's receipt of the Decommissioning Liquidated Damages (such period to be extended as and to the extent required for any period of Force Majeure), and to complete such Decommissioning in accordance with the Decommissioning Plan, such Governmental Approvals, and such other consents and approvals.

(iii) For the avoidance of doubt, (A) the Guarantor shall not have any obligation to pay any amount relating to Decommissioning Costs, including under Section 9.3.5(d) of the Agreement, other than Decommissioning Liquidated Damages as provided herein, and (B) upon the payment of such Decommissioning Liquidated Damages, (1) neither HQ Sub nor the Guarantor shall have any obligation to pay any other amount relating to Decommissioning Costs, including under Section 9.3.5(d) of the Agreement, and (2) neither HQSub nor the Guarantor shall be entitled to any reimbursement, refund or reduction if the actual Net Decommissioning Costs are less than the Decommissioning Liquidated Damages.

(c) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(d) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that HQSub has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, HQSub would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of HQSub.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of HQSub's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with HQSub or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and HQSub or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of HQSub, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not HQSub is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against HQSub.

Section 4. Subrogation. In any case, including HQSub's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against HQSub in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against HQSub and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of HQSub issues a stay or injunction prohibiting or preventing the Guarantor from reissuing this Guaranty, as contemplated by Section 17.1.1 of the Agreement, based in whole or in part on the effects on the estate of HQSub of any increase in the Stated Cap after the entry of an order of relief with respect to HQSub from the amount of the Stated Cap in the Purchaser Guaranty prior to such reissuance, and/or on the effects on the estate of HQSub of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Waiver of Immunities. The Guarantor agrees and acknowledges that this Guaranty and the Agreement constitute a commercial transaction. To the extent the Guarantor may be entitled, in any jurisdiction, to claim for itself, or any of its assets, revenues or properties, sovereign or other immunity, as the case may be, from service of process, suit, the jurisdiction of any court or arbitral tribunal, attachment (whether in aid of execution or otherwise) or enforcement of a judgment (interlocutory or final) or award or any other legal process in a matter arising out of or relating to this Guaranty, the Guarantor, to the fullest extent permitted by Applicable Law, agrees not to claim or assert, and hereby waives, such immunity. Without limiting the generality of the foregoing, the Guarantor agrees that the waivers set forth in this paragraph shall have the fullest scope permitted under the United States Foreign Sovereign Immunities Act of 1976, 28 U.S.C. § 1602 *et seq*., the Hydro-Québec Act (R.S.Q., chapter H-5) and under any other Applicable Law related to sovereign immunity.

(c) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of HQSub to execute and deliver the Agreement; (ii) the failure of HQSub to exist as a legal entity or the consolidation or merger of HQSub with or into any other corporation or other entity, or the sale, lease or other disposition by HQSub of all or substantially all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in HQSub; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization or liquidation of HQSub, the admission in writing by HQSub of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, HQSub, as debtor, or HQSub's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of HQSub to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against HQSub; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of HQSub shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or HQSub.

Section 7. Representations and Warranties.

The Guarantor represents and warrants that:

a) It is a corporation duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor’s constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor’s knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that HQSub may be entitled to under the Agreement, including any setoff or counterclaims that HQSub is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(c) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of HQSub in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of HQSub and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Construction Phase. The Guarantor's obligations with respect to the Guaranteed Obligations under Section 1(a)(i) and Section 1(a)(iii) of this Guaranty shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations. The Guarantor's obligations with respect to the Guaranteed Obligations under Section 1(a)(ii) of this Guaranty shall expire upon the earlier of full, final and indefeasible payment of such Guaranteed Obligations or the fortieth (40th) anniversary of the Commercial Operation Date, except that the Guarantor shall remain liable for any Guaranteed Obligations under Section 1(a)(ii) of this Guaranty relating to the period prior to such fortieth (40th) anniversary that are then due and remain unpaid and for which the Beneficiary shall have given written notice to the Guarantor pursuant to Section 1(b)(ii) of this Guaranty prior to such fortieth (40th) anniversary.

(c) Reissuance. Subject to Section 17.1.1(e) of the Agreement, upon the execution by the Guarantor and delivery to the Beneficiary, pursuant to Section 17.1.1 of the Agreement, of a new guaranty in replacement of this Guaranty, in the form of the Purchaser Guaranty attached as Attachment E-1 to the Agreement, with a revised Stated Cap redetermined in accordance with Section 17.1.1 of the Agreement, (i) this Guaranty shall terminate and (ii) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of this Guaranty, in such form as the Guarantor may reasonably request, with respect to such termination. This Section 9(c) shall not apply unless and until the Beneficiary shall have received a duly executed replacement guaranty in compliance with the terms and conditions for a reissued Purchaser Guaranty set forth in Section 17.1.1 of the Agreement.

(d) Transfer. Upon any Transfer by HQSub that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of HQSub's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that a Purchaser Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the Stated Cap shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the

Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(d) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement. Upon a collateral assignment of this Guaranty in connection with a collateral assignment of the Agreement permitted under the Agreement, the Guarantor shall cooperate with the Beneficiary and shall execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

HYDRO-QUÉBEC
Attention: Vice-President Financing, Treasury and Pension Fund
75, René-Lévesque Boulevard West
5th Floor
Montréal (Québec) Canada
H2Z 1A4
Facsimile: (514)289-5409

If to the Beneficiary:

NORTHERN PASS TRANSMISSION LLC
c/o NORTHEAST UTILITIES
Attention: Randy Shoop, Vice-President and Treasurer
56 Prospect Street
Hartford, Connecticut 06103
United States of America
Facsimile: (860)728-4585

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary. For the avoidance of doubt, this Guaranty may be reissued as provided in Section 9(c) of this Guaranty without a writing executed by the Beneficiary and such reissuance shall not require acceptance by the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

Section 19. Interpretation. The word “including” when used in this Guaranty shall be deemed to be followed by “without limitation” or “but not limited to, ” whether or not it is in fact followed by such words or words of like import.

Section 20. Counterparts. This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

HYDRO-QUÉBEC

By: ________________________________
Name:
Title:
Date:

By: ________________________________
Name:
Title:
Date:

Accepted:

NORTHERN PASS TRANSMISSION LLC

By: ________________________________
Name:
Title:
Date:

ATTACHMENT E-2

Form of Owner Guaranties

Please see the attached.

NSTAR
GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of _______________ ___, 2010, is made and entered into by **NSTAR**, a public utility holding company organized and existing as a voluntary association under the laws of the Commonwealth of Massachusetts and having its head office and principal place of business at 800 Boylston Street, 17th Floor, Boston, MA 02199, United States of America (hereinafter referred to as the "Guarantor"), in favor of **H.Q. Hydro Renewable Energy, Inc.**, a corporation organized and existing under the laws of the State of Delaware and having its principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **Northern Pass Transmission LLC,** a limited liability company organized and existing under the laws of the State of New Hampshire and having its place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as "NPT"), have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor indirectly owns, through a wholly-owned subsidiary, a portion of the beneficial ownership interests in NPT and will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of NPT under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. Guaranty.

(a) Guaranteed Obligations. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by NPT to the Beneficiary under the Agreement (including payment of NPT's indemnification obligations), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that NPT has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; provided, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed $6,250,000.00, plus (ii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Operation Phase shall have commenced under the Agreement; provided, further, that, subject to

Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(c) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that NPT has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, NPT would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of NPT.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of NPT's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with NPT or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and NPT or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of NPT, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not NPT is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against NPT.

Section 4. Subrogation. In any case, including NPT's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against NPT in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against NPT and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of NPT issues a stay or injunction prohibiting or preventing the Guarantor from amending this Guaranty, as contemplated by Section 17.1.2 of the Agreement, based in whole or in part on the effects on the estate of NPT of any increase in the aggregate liability of the Guarantor under Section 1(a) of this Guaranty after the entry of an order of relief with respect to NPT from the amount of the aggregate liability of the Guarantor under Section

1(a) of this Guaranty in the Owner Guaranty prior to such amendment, and/or on the effects on the estate of NPT of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of NPT to execute and deliver the Agreement; (ii) the failure of NPT to exist as a legal entity or the consolidation or merger of NPT with or into any other corporation or other entity, or the sale, lease or other disposition by NPT of all or substantially all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in NPT; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization, or liquidation of NPT, the admission in writing by NPT of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, NPT, as debtor, or NPT's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of NPT to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against NPT; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of NPT shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or NPT.

Section 7. Representations and Warranties.

The Guarantor represents and warrants that:

a) It is a public utility holding company duly organized as a voluntary association, validly existing and in good standing under the laws of the jurisdiction of its formation and has full voluntary association power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary voluntary association action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor's knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that NPT may be entitled to under the Agreement, including any setoff or counterclaims that NPT is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(b) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of NPT in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of NPT and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Operation Phase. The Guarantor's obligations with respect to the Guaranteed Obligations shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations.

(c) Transfer. Upon any Transfer by NPT that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of NPT's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that an Owner Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the aggregate liability of the Guarantor under Section 1(a) of this Guaranty shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(c) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

NSTAR
Attention: Senior Vice President Strategy, Law & Policy, General Counsel and Clerk
800 Boylston Street
17th Floor
Boston, Massachusetts 02199
United States of America
Facsimile: (781)441-3712

If to the Beneficiary:

H.Q. HYDRO RENEWABLE ENERGY, INC.
Attention: Christian G. Brosseau, President
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada

H2Z 1A4
Facsimile: (514)289-5484

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

Section 19. Interpretation. The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to," whether or not it is in fact followed by such words or words of like import.

Section 20. Trustee Liability. No shareholder or trustee of the Guarantor shall be held to any liability whatever for the payment of any sum of money or for damages or otherwise under this Guaranty. This Guaranty shall not be enforceable against any such trustee in their or his or her individual capacities or capacity and this Guaranty shall be enforceable against the trustees of the Guarantor only as such, and every Person having any claim or demand arising under this Guaranty and relating to the Guarantor, its shareholders or trustees shall look solely to the trust estate of the Guarantor for the payment or satisfaction thereof.

Section 21. Counterparts. This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NSTAR

By: ____
Name:
Title:
Date:

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: ____
Name:
Title:
Date:

NORTHEAST UTILITIES

GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of _______________ ___, 2010, is made and entered into by **Northeast Utilities**, a public utility holding company organized and existing as a voluntary trust under the laws of the Commonwealth of Massachusetts and having its head office and principal place of business at One Federal Street, Springfield, MA 01105, United States of America (hereinafter referred to as the "Guarantor"), in favor of **H.Q. Hydro Renewable Energy, Inc.**, a corporation organized and existing under the laws of the State of Delaware and having its principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **Northern Pass Transmission LLC,** a limited liability company organized and existing under the laws of the State of New Hampshire and having its place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as "NPT"), have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor indirectly owns, through a wholly-owned subsidiary, a portion of the beneficial ownership interests in NPT and will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of NPT under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. Guaranty.

(a) Guaranteed Obligations. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by NPT to the Beneficiary under the Agreement (including payment of NPT's indemnification obligations), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that NPT has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; provided, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed $18,750,000.00, plus (ii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Operation Phase shall have commenced under the Agreement; provided, further, that, subject to

Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(c) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that NPT has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, NPT would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of NPT.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of NPT's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with NPT or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and NPT or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of NPT, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not NPT is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against NPT.

Section 4. Subrogation. In any case, including NPT's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against NPT in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against NPT and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of NPT issues a stay or injunction prohibiting or preventing the Guarantor from amending this Guaranty, as contemplated by Section 17.1.2 of the Agreement, based in whole or in part on the effects on the estate of NPT of any increase in the aggregate liability of the Guarantor under Section 1(a) of this Guaranty after the entry of an order of relief with respect to NPT from the amount of the aggregate liability of the Guarantor under Section

1(a) of this Guaranty in the Owner Guaranty prior to such amendment, and/or on the effects on the estate of NPT of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of NPT to execute and deliver the Agreement; (ii) the failure of NPT to exist as a legal entity or the consolidation or merger of NPT with or into any other corporation or other entity, or the sale, lease or other disposition by NPT of all or substantially all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in NPT; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization, or liquidation of NPT, the admission in writing by NPT of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, NPT, as debtor, or NPT's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of NPT to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against NPT; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of NPT shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or NPT.

Section 7. Representations and Warranties.

The Guarantor represents and warrants that:

a) It is a public utility holding company duly organized as a voluntary trust, validly existing and in good standing under the laws of the jurisdiction of its formation and has full voluntary trust power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary voluntary trust action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor's knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that NPT may be entitled to under the Agreement, including any setoff or counterclaims that NPT is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(b) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of NPT in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of NPT and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Operation Phase. The Guarantor's obligations with respect to the Guaranteed Obligations shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations.

(c) Transfer. Upon any Transfer by NPT that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of NPT's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that an Owner Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the aggregate liability of the Guarantor under Section 1(a) of this Guaranty shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(c) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

NORTHEAST UTILITIES
Attention: Vice President and Treasurer
c/o Northeast Utilities Service Company
56 Prospect Street
Hartford, CT 06103
United States of America
Facsimile: (860)728-4632

With a copy to:

NORTHEAST UTILITIES
Attention: Senior Vice President and General Counsel
c/o Northeast Utilities Service Company
56 Prospect Street
Hartford, CT 06103

United States of America
Facsimile: (860)728-4581

If to the Beneficiary:

H.Q. HYDRO RENEWABLE ENERGY, INC.
Attention: Christian G. Brosseau, President
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Facsimile: (514)289-5484

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

Section 19. Interpretation. The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to," whether or not it is in fact followed by such words or words of like import.

Section 20. Trustee Liability. No shareholder or trustee of the Guarantor shall be held to any liability whatever for the payment of any sum of money or for damages or otherwise under this Guaranty. This Guaranty shall not be enforceable against any such trustee in their or his or her individual capacities or capacity and this Guaranty shall be enforceable against the trustees of the Guarantor only as such, and every Person having any claim or demand arising under this Guaranty and relating to the Guarantor, its shareholders or trustees shall look solely to the trust estate of the Guarantor for the payment or satisfaction thereof.

Section 21. Counterparts. This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NORTHEAST UTILITIES

By: ______________________________________
Name:
Title:
Date:

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: ______________________________________
Name:
Title:
Date:

ATTACHMENT F

Subordination Terms

1. Definitions. For purposes of this Attachment F, capitalized terms that are defined in the Transmission Service Agreement, dated as of October 4, 2010 (as amended, amended and restated, supplemented, waived or otherwise modified, the "Agreement"), by and between Northern Pass Transmission LLC, as Owner, and Hydro Renewable Energy Inc. (f/k/a H.Q. Hydro Renewable Energy, Inc.), as Purchaser, shall have the same meanings as those set forth in the Agreement. In addition, the following terms shall have the following meanings:

"Collateral" means, at any time, all property or assets (including limited liability company membership interests) subject to (or intended by the Loan Documents or the Agreement to be subject to) a Senior Lien or a Junior Lien.

"Collateral Proceeds" has the meaning set forth in Paragraph 9.

"DIP Financing" has the meaning set forth in Paragraph 10.2.

"Discharge of Project Debt Obligations" means, except to the extent otherwise expressly provided in Paragraph 13: (a) the indefeasible payment in full in cash and discharge of the principal of, and interest on, all indebtedness outstanding under the Loan Documents and constituting Project Debt Obligations; (b) the indefeasible payment in full in cash and discharge of all other Project Debt Obligations that are due and payable or otherwise accrued and owing at or prior to the time such principal and interest are paid; (c) termination or expiration of all commitments, if any, to extend credit that would constitute Project Debt Obligations; and (d) termination or cash collateralization of all letters of credit issued under the Loan Documents and constituting Project Debt Obligations.

"Junior Lien" means any Lien that presently exists or that may exist or arise at any time hereafter securing the TSA Obligations, including those under the Purchaser's Security Documents.

"Lien" means any lien, mortgage, pledge, assignment, security interest, fixed or floating charge or encumbrance of any kind (including any conditional sale or other title retention agreement, any lease in the nature thereof, and any agreement to give any security interest) and any option, trust or deposit or other preferential arrangement having the practical effect of any of the foregoing.

"Owner Party" means Owner and the members of Owner pledging membership interests in Owner as Collateral.

"Proceeding" means: (a) any voluntary or involuntary case or proceeding under the Bankruptcy Code with respect to any Owner Party; (b) any other voluntary or involuntary insolvency, reorganization or bankruptcy case or proceeding, or any receivership, liquidation, reorganization or other similar case or proceeding with respect to any Owner Party or with respect to a material portion of its respective assets; (c) any liquidation, dissolution, reorganization or winding up of any Owner Party whether voluntary or involuntary and whether or not involving insolvency or bankruptcy; or (d) any assignment for the benefit of creditors or any other marshalling of assets and liabilities of any Owner Party.

"Recovery" has the meaning set forth in Paragraph 13.

"Senior Lien" means any Lien that presently exists or that may exist or arise at any time hereafter securing the Project Debt Obligations, including any Lien under the Loan Documents.

"Standstill Period" has the meaning set forth in Paragraph 4(a)(i).

"TSA Obligations" means the obligations of Owner under the Agreement secured by the Purchaser Security Documents.

2. Subordination of Junior Lien.

2.1 Any and all Senior Liens shall be prior and superior in all respects to any and all Junior Liens. Any and all Junior Liens shall be junior and subordinate in all respects to any and all Senior Liens. For the avoidance of doubt and as set forth in Section 17.2.2 of the Agreement, any and all Junior Liens shall be superior in priority to all indebtedness (other than the Project Debt Obligations) of Owner secured by the Collateral.

2.2 The provisions of Paragraph 2.1 shall apply irrespective of:

(a) the date, time, order, manner or method of grant, attachment or perfection of the Liens created by any Loan Document or any Purchaser's Security Document;

(b) the date, time, order, manner or method of filing or recording of financing statements or other documents filed or recorded to perfect Liens on any Collateral;

(c) the rules for determining perfection or priority under the Uniform Commercial Code or any other law governing the relative priorities of secured creditors; or

(d) any defect or deficiency in, or failure to attach or perfect, the Senior Liens or the Junior Liens.

2.3 Nothing in the Subordination Agreement shall (a) restrict or interfere with the exercise of Purchaser's rights and remedies under the Agreement, whether as set forth thereunder, at law or in equity, except with respect to Purchaser's rights and remedies in respect of Junior Liens, (b) prevent Owner from making, or prevent Purchaser from receiving, payments under the Agreement at any time, so long as such receipt is not the direct or indirect result of the exercise by Purchaser of rights or remedies in respect of the Junior Liens, or enforcement thereof, in contravention of the Subordination Agreement, or (c) otherwise affect or limit the obligations of Owner under the Agreement, the Purchaser's Security Documents or the Loan Documents. The Subordination Agreement shall be solely for the benefit of Purchaser and the Financing Parties and not of any other Person (including any Owner Party).

2.4 The parties to the Subordination Agreement intend that the Collateral subject to the Senior Lien and the Collateral subject to the Junior Lien shall be the same. In furtherance of the foregoing, the parties to the Subordination Agreement agree, subject to the other provisions hereof, upon request by the Financing Parties or Purchaser, to cooperate in good faith (and to direct their counsel to cooperate in good faith) from time to time in order to determine (a) the specific items included in the Collateral subject to the Senior Lien and the Collateral subject to the Junior Lien, and (b) the steps to be taken to perfect their respective Liens thereon.

3. Subordination Respecting Additional Advances. Without limiting the provisions of Paragraph 2, the Junior Liens are, and shall be, expressly subject and subordinate in all respects to the Senior Liens that secure any and all advances made at any time or from time to time on or with respect to the Project Debt Obligations, whenever made, including any and all of such advances, interest, charges, fees and expenses that may increase the indebtedness evidenced and secured by the Loan Documents.

4. Exercise of Remedies.

(a) Until the Discharge of Project Debt Obligations has occurred, whether or not any Proceeding has been commenced by or against Owner or any other Owner Party, Purchaser:

(i) will not exercise or seek to exercise any rights or remedies (including setoff and credit bid) under the Purchaser's Security Documents or the Junior Liens with respect to any Collateral or institute any action or proceeding with respect to such rights or remedies (including any action of foreclosure or any Proceeding); provided, that Purchaser may exercise any or all such rights or remedies after a period of at least one hundred eighty (180) days has elapsed (such one hundred eighty (180)-day period, the "Standstill Period") since the date on which Purchaser has notified the Financing Parties that Purchaser is permitted to enforce any or all of its rights and remedies under the Purchaser's Security Documents in accordance with Section 15.4(e) of the Agreement, if the Owner Default giving rise to such rights or remedies shall then be continuing; provided, further, that, notwithstanding anything herein to the contrary, in no event shall Purchaser exercise any rights or remedies under the Purchaser Security Documents or the Junior Liens with respect to the Collateral if, notwithstanding the expiration of the Standstill Period, the Financing Parties shall have commenced and be diligently pursuing the exercise of their rights or remedies with respect to all or any material portion of the Collateral (prompt notice of such exercise to be given by the Financing Parties to Purchaser).

(ii) will not contest, protest or object to any foreclosure proceeding or action brought by a Financing Party or any other exercise by a Financing Party of any rights and remedies relating to the Collateral under the Loan Documents or the Senior Liens consistent with the Subordination Agreement, the Agreement and Applicable Law; and

(iii) will not object to the forbearance by a Financing Party from bringing or pursuing any foreclosure proceeding or action or any other exercise of any rights or remedies relating to the Senior Liens or the Collateral, in each case, so long as the Junior

Liens attach to the proceeds thereof, subject to the relative priorities described in Paragraph 2.

(b) Notwithstanding the foregoing, Purchaser may:

(i) file a claim or statement of interest with respect to the TSA Obligations; provided, that a Proceeding has been commenced by or against Owner;

(ii) take any action (not adverse to the priority status of the Senior Liens, or the rights of any Financing Party to exercise remedies in respect thereof as provided in the Subordination Agreement) in order to create, perfect, preserve or protect the Junior Liens;

(iii) file any necessary responsive or defensive pleadings in opposition to any motion, claim, adversary proceeding or other pleading made by any Person objecting to or otherwise seeking the disallowance or avoidance of the claims of Purchaser or of the Junior Liens, including any claims secured by the Collateral, if any, in each case in accordance with the terms of the Subordination Agreement; and

(iv) vote on any plan of reorganization, file any proof of claim, make other filings and make any arguments and motions that are, in each case, in accordance with the terms of the Subordination Agreement, with respect to the TSA Obligations and the Collateral; provided, that Purchaser shall not (A) vote against any plan of reorganization supported by the Financing Parties unless Purchaser's negative vote as a general unsecured creditor in a class of claims that includes other general unsecured creditors (assuming that its full claim were voted as a general unsecured claim) would be sufficient to result in such class voting to not accept such plan of reorganization, or (B) vote in favor of, or otherwise support, a plan of reorganization not supported by the Financing Parties unless Purchaser's affirmative vote as a general unsecured creditor in a class of claims that includes other general unsecured creditors (assuming that its full claim were voted as a general unsecured claim) would be sufficient to result in such class voting to accept such plan of reorganization.

(c) Subject to Paragraphs 4(a) and (b) and Paragraph 10.4(b):

(i) Purchaser agrees that it will not take any action that would hinder any exercise of remedies under the Loan Documents or Senior Liens or that is otherwise prohibited hereunder, including any sale, lease, exchange, transfer or other disposition of the Collateral, whether by foreclosure or otherwise;

(ii) Purchaser hereby waives any and all rights it may have as a junior lien creditor or otherwise to notice of any action by the Financing Parties seeking to enforce or collect the Project Debt Obligations or the Senior Liens granted in any of the Collateral undertaken in accordance with the Subordination Agreement, regardless of whether or not any action or failure to act by or on behalf of the Financing Parties is adverse to the interests of Purchaser;

(iii) Purchaser hereby waives any and all rights it may have as a junior lien creditor or otherwise to object to the manner in which the Financing Parties seek to enforce or collect the Project Debt Obligations or the Senior Liens granted in any of the Collateral undertaken in accordance with the Subordination Agreement, regardless of whether or not any action or failure to act by or on behalf of the Financing Parties is adverse to the interests of Purchaser; and

(iv) Purchaser hereby acknowledges and agrees that no covenant, agreement or restriction contained in the Purchaser's Security Documents shall be deemed to restrict in any way the rights and remedies of the Financing Parties with respect to the Collateral as set forth in the Subordination Agreement and the Loan Documents.

(d) Anything to the contrary in the Subordination Agreement notwithstanding, and both before and during any Proceeding, except as specifically prohibited by Paragraphs 4(a)(i) and 4(c), Purchaser may take any actions and exercise any and all rights and remedies that would be available to a holder of unsecured claims against Owner in accordance with the Agreement and Applicable Law.

5. Non-Disturbance. So long as the Agreement has not been terminated in accordance with its terms, Purchaser's rights under the Agreement shall not be disturbed, diminished or interfered with by the Financing Parties, and the Financing Parties shall not take any action or request any relief or remedy that would terminate the Agreement or otherwise impair Purchaser's rights thereunder, notwithstanding any rights the Financing Parties may have against Owner under the Loan Documents or otherwise. If, pursuant to the Loan Documents, the Financing Parties or their designee forecloses on or enters into possession of the Northern Pass Transmission Line or other Collateral, then, provided the Agreement has not been terminated in accordance with its terms, the Financing Parties or such designee, as the case may be, and any transferee of the Northern Pass Transmission Line or other Collateral or an interest therein, shall be bound by all of the terms of the Agreement and the Agreement shall continue in full force and effect as if such party had taken the place of Owner under the Agreement; provided, however, that recourse to the Financing Parties or their designee in respect of the Agreement shall be limited to the Collateral. Should the Financing Parties sell, assign, or otherwise transfer the Northern Pass Transmission Line or other Collateral or an interest therein prior to the termination of the Agreement in accordance with its terms, such transfer shall be expressly conditioned on the transferee agreeing to be bound by the terms of the Agreement. If, (a) pursuant to the Loan Documents, the Financing Parties or their designee forecloses on, or enters into possession of, the Northern Pass Transmission Line or other Collateral, and (b) the Agreement is rejected or terminated as a result of any Proceeding affecting Owner, then if, within thirty (30) days after the occurrence of such an event, Purchaser shall so request, Purchaser and the Financing Parties or their designee or a transferee, as applicable, shall execute and deliver a new agreement having identical terms as the Agreement (subject to any conforming changes necessitated by the substitution of parties); provided, that (i) the term under the new agreement shall be no longer than the remaining balance of the term specified in the Agreement, and (ii) prior to the execution of such new agreement, Purchaser shall cure any outstanding payment and performance defaults under the Agreement, excluding any performance defaults that, by their nature, are incapable of being cured, and upon execution of such new agreement, Purchaser and the Financing Parties or their

designee or a transferee, as applicable, shall be liable for all obligations arising under such new agreement.

6. Actions Respecting Collateral.

6.1 Until the Discharge of Project Debt Obligations has occurred, the Financing Parties shall, except as otherwise expressly provided herein, have the exclusive right to enforce rights, exercise remedies (including setoff and credit bid) and make determinations regarding the release, disposition or restrictions of Collateral and may exercise their rights and remedies under the Loan Documents and the Senior Liens in any manner in their sole discretion in compliance with Applicable Law, and without consultation with or the consent of Purchaser, whether in a Proceeding or otherwise. The Financing Parties' rights and remedies under the Subordination Agreement shall not be prejudiced by any action omitted or undertaken by it with respect to the Project Debt or any security therefor, consistent with the Loan Documents and the Subordination Agreement, and Purchaser hereby irrevocably and unconditionally waives all of the following:

(a) notice of acceptance by the Financing Parties of the Subordination Agreement;

(b) notice of the existence or creation or non-payment of any Project Debt Obligations; and

(c) all diligence in collection or protection of or realization upon the Project Debt Obligations or any security therefor.

6.2 The Financing Parties may, without affecting the priority of Liens contemplated hereby, do all or any of the following, all in the sole discretion of the Financing Parties and without regard for the effect thereof on Purchaser: (a) release any security for the Project Debt Obligations (including that provided by the Loan Documents or by any guaranty or letter of credit) or retain or obtain a security interest in other property to secure any or all of the Project Debt Obligations; (b) release, obtain or retain the primary or secondary obligation of any guarantor or endorser or any other Person with respect to any or all of the Project Debt Obligations; (c) to the extent Owner is not prohibited from doing so under the Agreement, refinance, extend, renew, defease, amend, modify, supplement, restructure, replace, refund or repay, or issue other indebtedness, in exchange or replacement for, the Project Debt, in whole or in part; and (d) obtain satisfaction of the Project Debt Obligations from the Collateral without proceeding to enforce any guaranty, letter of credit, or other collateral or security for any of the Project Debt Obligations or any other right or remedy.

6.3 In connection with (a) an enforcement of any Senior Lien or of the rights or remedies with respect to the Project Debt Obligations or (b) a disposition of assets, which enforcement or disposition (x) is expressly permitted by the Agreement and (y) does not, by the terms of the Agreement, require as a consequence of such enforcement or disposition that the Agreement be assumed by the purchaser of such assets, the Junior Lien shall be released on any such assets constituting Collateral at the time and to the extent the Senior Lien on such Collateral is released by the Financing Parties. Purchaser hereby appoints the Financing Parties as attorney-in-fact for the purposes of releasing such Collateral.

6.4 Purchaser shall not, in any Proceeding or otherwise, oppose any sale or disposition of the Collateral or any part thereof that is supported by the Financing Parties and is in compliance with the Agreement, the Subordination Agreement, and Applicable Law, and Purchaser will be deemed to have consented under Section 363 of the Bankruptcy Code (and otherwise) to any such sale of the Collateral or any part thereof supported by the Financing Parties; provided, that the proceeds thereof are applied to the reduction of the Project Debt Obligations and thereafter in the manner contemplated by Paragraph 7.1.

6.5 Unless and until the Discharge of Project Debt Obligations has occurred, the Financing Parties shall have the sole and exclusive right, subject to the rights of the Owner Parties under the Loan Documents, to adjust settlement for any insurance policy covering the Collateral in the event of any loss thereunder and to approve any award granted in any condemnation or similar proceeding (or any deed in lieu of condemnation) affecting the Collateral. Unless and until the Discharge of Project Debt Obligations has occurred, and subject to the rights of the Owner Parties under the Loan Documents, all proceeds of any such policy and any such award (or any payments with respect to a deed in lieu of condemnation) in respect of the Collateral shall be paid to the Financing Parties pursuant to the terms of the Loan Documents (including for purposes of cash collateralization of letters of credit) and thereafter, to the extent that (a) the Discharge of Project Debt Obligations has occurred and (b) Purchaser would be entitled to such proceeds under the second sentence of Paragraph 7.1, to Purchaser. Until the Discharge of Project Debt Obligations has occurred, if Purchaser shall, at any time, receive any proceeds of any such insurance policy or any such award or payment in contravention of the Subordination Agreement, it shall pay such proceeds over to the Financing Parties in accordance with the last sentence of Paragraph 7.1.

7. Proceeds.

7.1 So long as the Discharge of Project Debt Obligations has not occurred, whether or not any Proceeding has been commenced by or against Owner, any Collateral or proceeds thereof received in connection with the sale or other disposition of, or collection on, such Collateral upon the exercise of remedies by a Financing Party, shall be applied by the Financing Parties to the Project Debt Obligations in such order as specified in the Loan Documents. Upon the Discharge of Project Debt Obligations, if (a) there has been and continues to be an Owner Default under the Agreement, (b) the amount of damages suffered by Purchaser as a result of such Owner Default has been agreed in writing between Owner and Purchaser or determined in accordance with Article 18 of the Agreement, and (c) Owner shall not have paid such amount on or before the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, the Financing Parties shall then deliver to Purchaser any Collateral and proceeds of Collateral held by any Financing Party in the same form as received, with any necessary endorsements or as a court of competent jurisdiction may otherwise direct to be applied by Purchaser to the TSA Obligations in such order as specified in the Purchaser's Security Documents.

7.2 If

(a) Purchaser shall receive any Collateral or proceeds of any Collateral in contravention of the Subordination Agreement, or

(b) the Senior Liens do not attach to, or are not perfected or enforceable with respect to, any Collateral for any reason, and Purchaser shall receive any distribution or recovery with respect to, or allocable to, the value of such Collateral or any proceeds, thereof, then Purchaser agrees that any such Collateral, distribution, recovery or proceeds shall (for so long as the Discharge of Project Debt Obligations has not occurred) be segregated and held in trust and forthwith paid over to the Financing Parties in the same form as received without recourse, representation or warranty (other than a representation of Purchaser that it has not otherwise sold, assigned, transferred or pledged any right, title or interest in and to such distribution or recovery), but with any necessary endorsements or as a court of competent jurisdiction may otherwise direct until such time as the Discharge of Project Debt Obligations has occurred. The Financing Parties are hereby authorized to make any such endorsements as agent for Purchaser. This authorization is coupled with an interest and is irrevocable.

8. Covenants.

8.1 So long as the Discharge of Project Debt Obligations has not occurred, Purchaser hereby agrees that it will not modify or amend any of the Purchaser's Security Documents, without the Financing Parties' prior express written consent (other than to conform the Purchaser's Security Documents to modifications or amendments to the Financing Parties' security documents to the extent consistent with Section 17.2.1 of the Agreement). The Financing Parties shall notify Purchaser of any such modifications or amendments.

8.2 So long as the Discharge of Project Debt Obligations has not occurred, Purchaser shall not, without the prior written consent of the Financing Parties, sell, assign, or otherwise transfer, in whole or in part, any rights in the Purchaser's Security Documents to any other Person unless (1) such action is made in connection with an assignment of the Agreement to such Person that is permitted in accordance with the terms of the Agreement, (2) such action is made expressly subject to the Subordination Agreement and (3) the transferee expressly acknowledges to the Financing Parties, by a writing in form and substance reasonably satisfactory to the Financing Parties, the subordination provided for in the Subordination Agreement and agrees to be bound by all of the terms thereof.

8.3 The Financing Parties agree to hold that part of the Collateral that is in their possession or control (or in the possession or control of their agents or bailees) to the extent that possession or control thereof is taken to perfect a Lien thereon under the Uniform Commercial Code as bailee for Purchaser (such bailment being intended, among other things, to satisfy the requirements of Sections 8-301(a)(2) and 9-313(c) of the Uniform Commercial Code) and any assignee of Purchaser, solely for the purpose of perfecting the security interest granted under the Purchaser's Security Documents. The Financing Parties shall have no obligation whatsoever to Purchaser to ensure that the Collateral is genuine or owned by any of the Owner Parties or to preserve rights or benefits of any Person except as expressly set forth in this Paragraph 8.3. The duties and responsibilities of the Financing Parties to Purchaser under this Paragraph 8.3 shall be limited solely to holding the Collateral as bailee in accordance with this Paragraph 8.3 and delivering the Collateral upon a Discharge of Project Debt Obligations as provided in the Subordination Agreement. The Financing Parties acting pursuant to this Paragraph 8.3 shall not have a fiduciary relationship in respect of Purchaser.

9. Liquidation; Dissolution; Bankruptcy. Without limitation of the provisions of Paragraph 2.3(b), upon any payment or distribution of Collateral of any kind or character, whether in cash, securities or other property, to creditors of Owner in a liquidation or dissolution of Owner, whether voluntary or involuntary, or in a Proceeding relating to Owner or its property or creditors ("Collateral Proceeds"):

(a) the Financing Parties shall be entitled to receive payment in full, in cash or cash equivalents, of the Project Debt Obligations before Purchaser or any other holder of the TSA Obligations shall be entitled to receive, for or on account of the Purchaser's Security Documents, any payment of Collateral Proceeds with respect to any TSA Obligations or on account of any purchase or other acquisition of any TSA Obligations by Owner; and

(b) so long as the Discharge of Project Debt Obligations has not occurred, any payment or distribution of Collateral Proceeds for or on account of the Purchaser's Security Documents, to which Purchaser would be entitled but for this Paragraph 9, shall be made by Owner or by any receiver, trustee in bankruptcy, liquidating trustee, agent or other Person making such payment of distribution, directly to the Financing Parties to the extent necessary to pay all such Project Debt Obligations in full.

10. Proceedings.

10.1 Each of (a) Purchaser and (b) the Financing Parties agrees that it will not (and hereby waives any right to) contest, or support any other Person in contesting, in any proceeding (including any Proceeding), any Project Debt Obligation or TSA Obligation or the priority, validity or enforceability of any Senior Lien or Junior Lien, as the case may be, or the provisions of the Subordination Agreement; provided, that nothing in the Subordination Agreement shall be construed to prevent or impair the rights of the Financing Parties or Purchaser to enforce the Subordination Agreement, including the provisions of the Subordination Agreement relating to the priority of the Senior Liens and Junior Liens.

10.2 Until the Discharge of Project Debt Obligations has occurred, if Owner or any other Owner Party shall be subject to any Proceeding and the Financing Parties shall desire to permit (a) the use of cash collateral on which the Financing Parties or any other creditor has a Lien or (b) Owner or any other Owner Party to obtain financing, whether from the Financing Parties or any other Person, under Section 364 of the Bankruptcy Code ("DIP Financing"), then Purchaser agrees that it will raise no objection to the use of such cash collateral or to such DIP Financing, respectively, and to the extent the Senior Liens are subordinated to, or *pari passu* with, such DIP Financing, Purchaser will subordinate the Junior Liens in the Collateral to the Liens securing such DIP Financing (and all obligations relating thereto) and will not request adequate protection or any other relief in connection therewith (except as expressly agreed by the Financing Parties or to the extent permitted by Paragraph 10.4); provided, that the aggregate principal amount of the DIP Financing, plus the aggregate outstanding principal amount of Project Debt Obligations, does not exceed the principal amount of Project Debt permitted to constitute Project Debt Obligations in accordance with the second sentence of the definition thereof, and Purchaser retains the right to object to any ancillary agreements or arrangements regarding the use of cash collateral or the DIP Financing that are materially prejudicial to Purchaser's interests. Purchaser agrees that it will not raise any objection or oppose a motion to sell or otherwise dispose of any

Collateral free and clear of the Junior Liens or other claims under Section 363 of the Bankruptcy Code if (i) the requisite Financing Parties have consented to such sale or disposition of such assets, (ii) such motion does not impair the rights of Purchaser under Section 363(k) of the Bankruptcy Code, and (iii) the Junior Liens attach to the proceeds of such sale or disposition subject to the relative priorities described in Paragraph 2.

10.3 If any Financing Party is required in any Proceeding or otherwise to turn over or otherwise pay to the estate of Owner or any other Owner Party any amount paid in respect of Project Debt Obligations, then such Financing Party shall be entitled to a reinstatement of Project Debt Obligations with respect to all such recovered amounts.

10.4 The following provisions shall apply with respect to requests for adequate protection:

(a) Purchaser agrees that it shall not contest (or support any other Person in contesting):

(i) any request by the Financing Parties for adequate protection; or

(ii) any objection by the Financing Parties to any motion, relief, action or proceeding based upon the Financing Parties claiming a lack of adequate protection.

(b) Notwithstanding the foregoing provisions in this Paragraph 10.4, in any Proceeding:

(i) if the Financing Parties (or any subset thereof) are granted adequate protection in the form of additional collateral in connection with any use of cash collateral or any DIP Financing, then Purchaser may seek or request adequate protection in the form of a Lien on such additional collateral, which Lien will be subordinated to the Liens on such cash collateral and to the Senior Liens or the Liens securing the DIP Financing (and all obligations relating thereto) on the same basis as the other Junior Liens are so subordinated to the Senior Liens under such Subordination Agreement; and

(ii) in the event Purchaser seeks or requests adequate protection in respect of the TSA Obligations and such adequate protection is granted in the form of additional collateral, then Purchaser agrees that the Financing Parties shall also be granted a Lien on such additional collateral as security for the Project Debt Obligations and for any cash collateral use or DIP Financing provided by the Financing Parties and that any Lien on such additional collateral securing the TSA Obligations shall be subordinated to the Senior Lien on such additional collateral and the Lien on such additional collateral securing any such DIP Financing provided by the Financing Parties (and all obligations relating thereto) and to any other Liens granted to the Financing Parties as adequate protection on the same basis as the other Junior Liens are so subordinated to such Senior Liens under the Subordination Agreement.

Except as otherwise expressly set forth in Paragraph 10.2, this Paragraph 10.4 or in connection with the exercise of remedies with respect to the Collateral, nothing herein shall limit the rights of Purchaser from seeking adequate protection with respect to its rights in the Collateral in any

Proceeding (including adequate protection in the form of a cash payment, periodic cash payments or otherwise).

10.5 Except as otherwise expressly provided herein, nothing contained in the Subordination Agreement shall prohibit or in any way limit the Financing Parties from objecting in any Proceeding or otherwise to any action taken by Purchaser, including the asserting by Purchaser of any of its rights and remedies under the Agreement or the Purchaser's Security Documents.

11. Subrogation. Following the Discharge of the Project Debt Obligations, Purchaser shall be subrogated to the rights of the Financing Parties to receive distributions of assets of Owner or payment by or on behalf of Owner made on the Project Debt Obligations, until all TSA Obligations shall be paid in full.

12. Further Assurances. So long as the Discharge of Project Debt Obligations has not occurred, Purchaser shall, within a reasonable time after request by the Financing Parties, execute, acknowledge and deliver to the Financing Parties any and all further other instruments in recordable form on such terms and conditions as may be customary for transactions of a similar nature and as may be reasonably satisfactory to Purchaser and the Financing Parties to further, advance, implement, confirm, evidence or facilitate the purposes addressed in the Subordination Agreement.

13. Avoidance Issues. If any Financing Party is required in any Proceeding or otherwise to turn over or otherwise pay to the estate of Owner any amount paid in respect of Project Debt Obligations (a "Recovery"), then such Financing Party shall be entitled to a reinstatement of Project Debt Obligations with respect to all such recovered amounts. If the Subordination Agreement shall have been terminated prior to such Recovery, the Subordination Agreement shall be reinstated in full force and effect, and such prior termination shall not diminish, release, discharge, impair or otherwise affect the obligations of the parties hereto from such date of reinstatement.

14. Notation on the Purchaser Mortgage. Purchaser agrees that, promptly after any Subordination Agreement has been executed and the Financing Parties thereunder furnish to Purchaser the relevant recordation information, Purchaser will cause the following statement to be typed or printed conspicuously at the top of the first page of the Purchaser Mortgage (including by an amendment to the Purchaser Mortgage with respect to any Subordination Agreement executed after the Purchaser Mortgage is initially filed) "This instrument and the obligations it evidences or secures are subject to the provisions of that certain Subordination Agreement dated as of ____________, 20__, a memorandum of which is recorded in Book [____], page [____], [_____________] County, New Hampshire."

ATTACHMENT G

Letter Agreement

Please see the attached.

October 4, 2010

Mr. Christian G. Brosseau
Vice President, Wholesale Markets
Hydro-Québec Production
75 West, René-Lévesque Blvd, 18th Floor
Montréal (Québec) Canada H2Z 1A4

Re: Letter Agreement for Recovery of Northern Pass Transmission Line Project Development Costs

Dear Mr. Brosseau:

As you are aware, Northern Pass Transmission LLC ("NPT") and H.Q. Hydro Renewable Energy, Inc. ("HQRE"), an indirect, wholly owned subsidiary of Hydro-Québec, acting through its Hydro-Québec Production division ("HQP") (NPT and HQP also referred to herein individually as a "Party", or collectively as the "Parties"), have entered into a Transmission Service Agreement of even date herewith ("TSA") that governs the rates, terms and conditions under which HQRE will acquire firm transmission service from NPT over a 1,200 MW high voltage direct current transmission line that will run from Québec to a point in New Hampshire ("Northern Pass Transmission Line Project"). The TSA will be filed with the Federal Energy Regulatory Commission ("FERC") for acceptance as a rate schedule.

Upon the termination of the TSA at any time prior to the commencement of the Construction Phase (as that term is defined in the TSA), HQP has agreed to reimburse NPT for certain Project Development Costs (as defined below), as further set forth in Appendix A. By this letter agreement, the Parties seek to confirm their agreement regarding reimbursement of the Project Development Costs.

1. **Execution Date; FERC Effective Date.** This letter agreement shall be binding and effective as of the date first set forth above (the "Execution Date"); *provided, however*, that any payment hereunder shall be subject to prior acceptance by FERC of this letter agreement ("FERC Effective Date"). A copy of this letter agreement is an attachment to the TSA that will be filed with FERC. NPT shall, however, file a copy of this letter agreement with FERC with a request for approval or acceptance only upon the occurrence of a PDC Payment Event.

2. **Project Development Costs; PDC Payment Event.** "Project Development Costs" mean the following costs incurred by NPT: (a) the Owner's Costs (as defined in the TSA) and (b) unless NPT has terminated the TSA, the costs and expenses associated with the drafting and negotiation of the TSA, in each case, from January 1, 2009 through the occurrence of a PDC Payment Event (as defined below) (the "Reimbursement Period").

Project Development Costs reimbursable under this letter agreement shall not exceed twelve million dollars ($12,000,000) (the "NTX Amount"). The Parties may by mutual written agreement increase the NTX Amount, however, neither NPT nor its affiliates shall have any obligation to incur Project Development Costs in accordance with a particular schedule or timeframe, or in excess of the NTX Amount.

For purposes of this letter agreement, a "PDC Payment Event" means the termination of the TSA by NPT or HQRE prior to the commencement of the Construction Phase or the rejection by FERC of the TSA.

3. **Reimbursement of Project Development Costs.** Subject to the terms and conditions of this letter agreement, HQP shall reimburse NPT, in accordance with this Section 3, for the Project Development Costs set forth in Appendix A attached hereto that NPT has incurred and will incur pursuant to this letter agreement. HQP approves the Project Development Costs incurred by NPT through August 31, 2010 (as shown in Section II of Appendix A).

3.1. **Monthly Allocations.** Section III of Appendix A contains monthly cash flow allocations for the period of September 1, 2010 through March 31, 2011. NPT shall not, in any month, incur Project Development Costs that, when combined with Project Development Costs previously incurred, exceed the total cumulative cash flow allocations through such month, unless and until NPT provides HQP a written explanation of the reason(s) for incurring such excess Project Development Costs and obtains HQP's consent to incur such excess Project Development Costs.

3.2. **Monthly Reports.** For each month following the Execution Date, NPT shall, within a reasonable time after the last day of each such month, provide HQP with a report reasonably detailing the Project Development Costs incurred during such month prior to the occurrence of a PDC Payment Event, if any. If HQP objects to any costs identified in such a report, HQP shall, within fourteen (14) calendar days, provide NPT with written notice of, and the basis for, such objection. NPT may, in its sole discretion, suspend the activities associated with the Project Development Costs that are the subject of an HQP objection (and the incurrence of such costs and expenses) until such objection is resolved by mutual agreement of the Parties.

3.3. **PDC Payment Event Invoices.** Following the occurrence of a PDC Payment Event, NPT shall submit to HQP a preliminary invoice(s) of all Project Development Costs incurred during the Reimbursement Period, but not to exceed the NTX Amount.

3.4. **Billing and Payment.** Within thirty (30) days after the FERC Effective Date, NPT shall render a final invoice(s) of Project Development Costs incurred during the Reimbursement Period (which invoiced amounts shall be consistent with Appendix A, the monthly reports, the NTX Amount and the conditions, if any, in the FERC order accepting or approving this letter agreement) to HQP at the address specified in Appendix B. HQP shall pay such final invoice(s) within thirty (30) calendar days of its receipt of such final invoice. All payments shall be made in immediately available funds payable to NPT, or by wire transfer to a bank named and account designated by NPT. Neither payment of such final invoice(s) by HQP, nor acceptance of payment by NPT, shall constitute a waiver of any rights or claims NPT or HQP may have under this letter agreement or the TSA.

4. **Term.** Unless otherwise agreed to by the Parties in writing, this letter agreement shall expire upon the earlier to occur of the commencement of the Construction Phase and the indefeasible payment in full by HQP to NPT of all amounts owed to NPT by HQP under this letter agreement.

5. **Termination.** Except as set forth in Sections 4 and 6, this letter agreement may only be terminated by mutual agreement of the Parties in writing.

6. **Effect of TSA.** Notwithstanding any other provision herein to the contrary, the Parties acknowledge and agree that, following the expiration or other termination of this letter agreement pursuant to its terms, the Parties rights and responsibilities concerning Project Development Costs (regardless of when incurred) shall be governed by the TSA and any FERC order accepting or approving the TSA, and HQP and its affiliates shall be without liability or obligation whatsoever under this letter agreement (including any payment or reimbursement obligation). Upon the commencement of the Construction Phase, the TSA shall supersede this letter agreement in its entirety and, except as set forth in Section 7, this letter agreement shall cease to have any further force and effect.

7. **Survival.** This letter agreement shall continue in effect after termination or expiration only to the extent necessary to provide for final billings, if any, and payments, if any, for Project Development Costs incurred in accordance with this letter agreement, and to permit the determination and enforcement of obligations arising while this letter agreement was in effect.

8. **Assignment.** No full or partial assignment by a Party of its interests under this letter agreement shall be valid without the express written consent of the other Party, which consent shall not be unreasonably withheld, delayed or conditioned.

9. **Notices.** Unless otherwise provided in this letter agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other shall be effective when delivered in writing and may be so given, tendered or delivered, by facsimile or email to the facsimile numbers or email addresses set out in Appendix B, or by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix B.

   Either Party may change the notice information in this letter agreement by giving seven (7) calendar days written notice prior to the effective date of the change.

10. **Governing Law; Disputes**. This letter agreement and the rights and duties of the Parties shall be governed by and construed, enforced and performed in accordance with the laws of the State of New York, without regard to its principles of conflicts of law. THE PARTIES HEREBY CONSENT TO THE EXCLUSIVE JURISDICTION OF THE COURTS OF THE STATE OF NEW YORK FOR ENFORCEMENT OF THIS LETTER AGREEMENT AND ANY OTHER LEGAL PROCEEDINGS ARISING OUT OF OR RELATING TO THE LETTER AGREEMENT AND THE TRANSACTIONS CONTEMPLATED UNDER THE LETTER AGREEMENT. EACH PARTY HEREBY IRREVOCABLY WAIVES AND RELEASES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, (a) ANY OBJECTION TO THE VENUE OF ANY SUCH PROCEEDING BROUGHT IN SUCH A COURT AND (b) ANY CLAIM THAT ANY SUCH PROCEEDING BROUGHT IN SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM.

11. **Amendments; Entire Agreement.** No provision in this letter agreement may be amended or waived except by a written instrument signed by the Parties. This letter agreement, and the TSA, constitute the entire understanding and agreement between the Parties with respect to the subject matter herein and supersede all prior representations and agreements, express or implied, oral or written with respect to the subject matter herein. References herein to this letter agreement shall include a reference to all attachments, including the Appendices.

12. **Confidentiality.** HQP shall not share with or otherwise disclose to Hydro-Québec TransÉnergie or any other Hydro-Québec division, subsidiary or affiliate with responsibility for construction of electric transmission and/or distribution facilities, the vendor specific rates or information contained in any invoices or other documentation provided to HQP or HQRE by NPT or NPT's members or affiliates pursuant to this letter agreement. Such information provided by NPT, if any, shall be held by HQP and HQRE as confidential and subject to the terms and conditions of that certain Confidentiality Agreement, dated as of February 29, 2008, by and between Northeast Utilities Service Company and H.Q. Energy Services (U.S.) Inc., the terms of which, to the extent not otherwise inconsistent with this letter agreement, are hereby incorporated herein and made a part hereof.

13. **Counterparts.** This letter agreement may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Parties acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

If HQP agrees to the foregoing terms of this letter agreement, please indicate HQP's agreement by having the appropriate respective duly authorized officer of HQP and HQRE countersign both originals of this letter agreement and returning one executed original to me.

Thank you for your care and attention to this matter,

Sincerely,

NORTHERN PASS TRANSMISSION LLC

James A. Muntz
President

AGREED AND ACCEPTED BY
HYDRO-QUÉBEC PRODUCTION

Christian G. Brosseau
Its Vice-President – Wholesale Markets, duly authorized

* * * * * *

The undersigned H.Q. Hydro Renewable Energy, Inc. acknowledges having read this letter agreement and agrees to be bound by the terms thereof, including Section 12.

H.Q. HYDRO RENEWABLE ENERGY, INC.

Christian G. Brosseau
President, duly authorized

Thank you for your care and attention to this matter,

Sincerely,

NORTHERN PASS TRANSMISSION LLC

____

James A. Muntz
President

AGREED AND ACCEPTED BY
HYDRO-QUÉBEC PRODUCTION

Christian G. Brosseau
Its Vice-President – Wholesale Markets, duly authorized

* * * * * *

The undersigned H.Q. Hydro Renewable Energy, Inc. acknowledges having read this letter agreement and agrees to be bound by the terms thereof, including Section 12.

H.Q. HYDRO RENEWABLE ENERGY, INC.

Christian G. Brosseau
President, duly authorized

Appendix A

I. Scope of Project Development Cost Activities

NPT has and will, subject to the terms of the letter agreement, incur the Project Development Costs as defined in Section 2 of the letter agreement for the costs set forth in Sections II and III of this Appendix A.

II. Project Development Costs Incurred Through August 2010

For the period January 1, 2009 through August 31, 2010, NPT has incurred Project Development Costs for work/services in support of the Northern Pass Transmission Line Project in the aggregate amount of **seven million six hundred three thousand six hundred dollars (US$7,603,600.00)**.

III. Monthly Allocations of Project Development Costs September – March 2011

For the period of September 1, 2010 through March 31, 2011, NPT anticipates that NPT will incur Project Development Costs for work/services in support of the Northern Pass Transmission Line Project in the aggregate amount of approximately **eight million three hundred sixty thousand one hundred dollars (US$8,360,100.00)** and in the monthly allocations set forth below. The foregoing is an estimate only. Actual costs incurred may be higher or lower depending on factors such as the Northern Pass Transmission Line Project schedule, changes in scope, changes in law, or unanticipated regulatory issues.

Category of Activity[1]	Jan. 2009 – Aug. 2010	Sept. 2010	Oct. 2010	Nov. 2010*	Dec. 2010**	Jan. 2011	Feb. 2011	Mar. 2011	Total Sept 2010 – Mar. 2011	Total Jan. 2009 – Mar. 2011
Legal	**1252.1**	**325.0**	**335.0**	**150.0**	**200.0**	**180.0**	**180.0**	**180.0**	**1550.0**	**2802.1**
Environmental	**979.7**	**380.0**	**380.1**	**90.0**	**72.0**	**50.0**	**50.0**	**50.0**	**1072.1**	**2051.8**
Routing Analysis & Preliminary Engineering	**1205.5**	**277.5**	**435.5**	**528.5**	**460.5**	**378.5**	**353.5**	**391.5**	**2825.5**	**4031.0**
Real Estate Services	**389.8**	**90.0**	**75.0**	**75.0**	**50.0**	**80.0**	**80.0**	**80.0**	**530.0**	**919.8**

[1] All amounts are in thousands (1,000s) of dollars.

Corporate Communications & Community Outreach	**308.3**	**40.3**	**20.0**	**25.0**	**25.0**	**10.0**	**10.0**	**10.0**	**140.3**	**448.6**
Miscellaneous	**223**	**43.9**	**51.2**	**56.9**	**62.2**	**67.1**	**71.9**	**76.8**	**430.0**	**653.0**
NPT Labor	**1734.1**	**214.2**	**215.5**	**224.6**	**224.1**	**223.0**	**222.7**	**223.1**	**1547.2**	**3281.3**
TSA Negotiation Costs	**1511.1**	**215.0**	**50.0**	**0**	**0**	**0**	**0**	**0**	**265.0**	**1776.1**
Cumulative Cash Flow Total	**7603.6**	**1585.9**	**1562.3**	**1150.0**	**1093.8**	**988.6**	**968.1**	**1011.4**	**8360.1**	**15,963.7**

* **Based on the monthly allocations, Project Development Costs will total $11,901,800.00 by November 30, 2010.**
** **Based on the monthly allocations, Project Development Costs will total $12,995,600.00 by December 31, 2010. NPT therefore anticipates that NPT will have incurred $12,000,000.00 in Project Development Costs, and reached the NTX Amount, by approximately early December 2010. At an appropriate time before the NTX Amount is reached, the Parties will consult on whether to increase the NTX Amount or curtail project development activities.**

Time Value of Money Charge

NPT will accrue, on a cumulative basis, a charge, equal to the time value of money, on all Project Development Costs. Such charge shall accrue against all Project Development Costs at an annual rate of 6.4% as of the Execution Date**,** and shall be adjusted monthly thereafter.

Appendix B

I. Addresses for Delivery of Notices and Billings

Notices:

NPT:	James A. Muntz, President Northeast Utilities Service Company 107 Selden Street Berlin, CT 06037 (860) 665-3315
	with a copy to:
	Duncan MacKay, Deputy General Counsel Northeast Utilities Service Company 107 Selden Street Berlin, CT 06037 (860) 665-3495
HQP:	Christian G. Brosseau, Vice President, Wholesale Markets Hydro-Québec Production 75 West, René-Lévesque Blvd, 18th Floor Montréal (Québec) Canada H2Z 1A4

Billings and Payments:

NPT:	Anne Bartosewicz, Project Director Northeast Utilities 107 Selden Street Berlin, CT 06037
HQP:	Maxime Lanctôt, Director, Business Development & Expertise Hydro-Québec Production 75 West, René-Lévesque Blvd, 17th Floor Montréal (Québec) Canada H2Z 1A4

II. Alternative Forms of Delivery of Notices

NPT:	Fax: (860) 665-6717 (attention James A. Muntz) Email: muntzja@nu.com
HQP:	Fax: (514) 289-5484 (attention Christian G. Brosseau) Email: brosseau.christian@hydro.qc.ca

ATTACHMENT H

Example of Calculation of Levelized Monthly Decommissioning Payment

This example is intended to illustrate the methodology for the calculation of the Levelized Monthly Decommissioning Payment. This example and the numbers used in this example are purely illustrative and are in no way intended to supersede Section 9.3 of the Agreement or the Formula Rate.

Formula

Levelized Monthly Decommissioning Payment equals:

Estimated Net Decommissioning Cost, multiplied by Decommissioning Payment Formula

"Decommissioning Payment Formula" means the following formula:

$$\frac{c}{[(1 + c)^{60} - 1]}$$

Where:

c is the reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (expressed as a percentage).

Assumptions

Estimated Net Decommissioning Cost, expressed in dollars for the year(s) during which they are expected to be incurred and then discounted to their present value at the beginning of the first calendar day after the end of the Decommissioning Payment Period, is $1,000,000.

Reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (c) is 0.40 percent.

Solving this equation, step by step

Levelized Monthly Decommission Payment equals:

1. $1,000,000 * (0.0040 / (((1 + 0.0040)^60) – 1))

2. $1,000,000 * (0.0040 / (((1.0040)^60) – 1))

3. $1,000,000 * (0.0040 / ((1.27064072) – 1))

4. $1,000,000 * (0.0040 / (0.27064072))

5 $1,000,000 * (0.01477974)

6. $14,779.74

Pursuant to Section 9.3.3(a) of the Agreement, $14,779.74 would be included in the Formula Rate for each month during the Decommissioning Payment Period.

ATTACHMENT I

Example of Calculation of Refund of Amounts Subject to Late Payment Interest

This example is intended to illustrate the methodology for the calculation of a subsequent refund of a late payment. This example and the numbers used in this example are purely illustrative and are in no way intended to supersede Section 14.5(c) of the Agreement or the first sentence of Section 14.5 of the Agreement

Assumptions

Interest Rate = 12 percent per annum (compounded monthly)

June 2011 Billing

Invoice Amount	$1,000
Date of Invoice	June 1, 2011
Due Date	June 15, 2011
Payment Date	July 1, 2011

The total amount due on the date of payment is $1,005, which amount is computed by adding $1,000 (the original amount invoiced) and $5 (the ½ month late interest fee).

Subsequent Refund

If later, on July 1, 2012, the aforesaid payment is required to be refunded, the refund will equal the $1,000 payment made on July 1, 2011 (the original amount invoiced), plus the interest accrued on that $1,000 payment from the due date of June 15, 2011 to the date of refund on July 1, 2012. To ensure that the refund does not double recover interest, the following language has been included in Section 14.5(c) of the Agreement: "If all or a portion of the amount [*here, the $1,000 payment due on June 15, 2011*] to which such interest relates [*here, the $5 late interest fee*] is later refunded pursuant to this Agreement [*here, on July 1, 2012*], then, in calculating that refund, such interest [*here, $5*] shall not be included in the refund.

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EVERSOURCE ENERGY

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

T **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2014

or

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to ___________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) 300 Cadwell Drive Springfield, Massachusetts 01104 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-02301	**NSTAR ELECTRIC COMPANY** (a Massachusetts corporation) 800 Boylston Street Boston, Massachusetts 02199 Telephone: (617) 424-2000	04-1278810
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) 300 Cadwell Drive Springfield, Massachusetts 01104 Telephone: (413) 785-5871	04-1961130

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Northeast Utilities	Common Shares, $5.00 par value	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
The Connecticut Light and Power Company	Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are outstanding:

$1.90	Series	of 1947
$2.00	Series	of 1947
$2.04	Series	of 1949
$2.20	Series	of 1949
3.90%	Series	of 1949
$2.06	Series E	of 1954
$2.09	Series F	of 1955
4.50%	Series	of 1956
4.96%	Series	of 1958
4.50%	Series	of 1963
5.28%	Series	of 1967
$3.24	Series G	of 1968
6.56%	Series	of 1968

NSTAR Electric Company	Preferred Stock, par value $100.00 per share, issuable in series, of which the following series are outstanding:

4.25%	Series
4.78%	Series

NSTAR Electric Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and each is therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

Yes	**No**
T	£

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes	**No**
£	T

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes	**No**
T	£

Indicate by check mark whether the registrants have submitted electronically and posted on its corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes	**No**
T	£

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
Northeast Utilities	T	£	£
The Connecticut Light and Power Company	£	£	T
NSTAR Electric Company	£	£	T
Public Service Company of New Hampshire	£	£	T
Western Massachusetts Electric Company	£	£	T

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act):

	Yes	No
Northeast Utilities	£	T
The Connecticut Light and Power Company	£	T
NSTAR Electric Company	£	T
Public Service Company of New Hampshire	£	T
Western Massachusetts Electric Company	£	T

The aggregate market value of Northeast Utilities' Common Shares, $5.00 par value, held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of Northeast Utilities' most recently completed second fiscal quarter (June 30, 2014) was $14,947,688,864 based on a closing market price of $47.27 per share for the 316,219,354 common shares outstanding on June 30, 2014.

Indicate the number of shares outstanding of each of the issuers' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding as of January 31, 2015
Northeast Utilities Common shares, $5.00 par value	317,203,765 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
NSTAR Electric Company Common Stock, $1.00 par value	100 shares
Public Service Company of New Hampshire Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company Common stock, $25.00 par value	434,653 shares

Northeast Utilities holds all of the 6,035,205 shares, 100 shares, 301 shares, and 434,653 shares of the outstanding common stock of The Connecticut Light and Power Company, NSTAR Electric Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company, respectively.

Northeast Utilities, The Connecticut Light and Power Company, NSTAR Electric Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company each separately file this combined Form 10-K. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

The following is a glossary of abbreviations or acronyms that are found in this report:

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

CL&P	The Connecticut Light and Power Company
CYAPC	Connecticut Yankee Atomic Power Company
MYAPC	Maine Yankee Atomic Power Company
NPT	Northern Pass Transmission LLC
NSTAR	Parent Company of NSTAR Electric, NSTAR Gas and other subsidiaries (prior to the merger with NU)
NSTAR Electric	NSTAR Electric Company
NSTAR Electric & Gas	NSTAR Electric & Gas Corporation, a former Northeast Utilities service company (effective January 1, 2014 merged into NUSCO)
NSTAR Gas	NSTAR Gas Company
NU or the Company	Northeast Utilities and subsidiaries, effective February 2, 2015, doing business as Eversource Energy
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO and other subsidiaries, which primarily include NU Enterprises, Inc. (the parent company of our unregulated businesses), HWP Company (formerly the Holyoke Water Power Company), The Rocky River Realty Company (a real estate subsidiary), and the consolidated operations of CYAPC and YAEC
NUSCO	Northeast Utilities Service Company (effective January 1, 2014 includes the operations of NSTAR Electric & Gas)
EETV	Eversource Energy Transmission Ventures, Inc., the parent company of NPT and Renewable Properties, Inc. (formerly Northeast Utilities Transmission Ventures, Inc.)
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's Regulated companies, comprised of the electric distribution and transmission businesses of CL&P, NSTAR Electric, PSNH, and WMECO, the natural gas distribution businesses of Yankee Gas and NSTAR Gas, the generation activities of PSNH and WMECO, and NPT
WMECO	Western Massachusetts Electric Company
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, YAEC and MYAPC
Yankee Gas	Yankee Gas Services Company
REGULATORS:	
DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Massachusetts Department of Public Utilities
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England, Inc., the New England Independent System Operator
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utilities Regulatory Authority
SEC	U.S. Securities and Exchange Commission
SJC	Supreme Judicial Court of Massachusetts
OTHER:	
AFUDC	Allowance For Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income/(Loss)
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CfD	Contract for Differences
Clean Air Project	The construction of a wet flue gas desulphurization system, known as "scrubber technology," to reduce mercury emissions of the Merrimack coal-fired generation station in Bow, New Hampshire
CO_2	Carbon dioxide
CPSL	Capital Projects Scheduling List
CTA	Competitive Transition Assessment
CWIP	Construction Work in Progress
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Share Purchase Plan
FERC ALJ	FERC Administrative Law Judge
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge

GSRP	Greater Springfield Reliability Project
GWh	Gigawatt-Hours
HQ	Hydro-Québec, a corporation wholly owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	Hydro Renewable Energy, Inc., a wholly owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
kV	Kilovolt
kW	Kilowatt (equal to one thousand watts)
kWh	Kilowatt-Hours (the basic unit of electricity energy equal to one kilowatt of power supplied for one hour)
LBR	Lost Base Revenue
LNG	Liquefied natural gas
LRS	Supplier of last resort service
MGP	Manufactured Gas Plant
MMBtu	One million British thermal units
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
NEEWS	New England East-West Solution
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NO_x	Nitrogen oxides
NU 2013 Form 10-K	The Northeast Utilities and Subsidiaries 2013 combined Annual Report on Form 10-K as filed with the SEC
PAM	Pension and PBOP Rate Adjustment Mechanism
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PPA	Pension Protection Act
RECs	Renewable Energy Certificates
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segment excluding the wholesale transmission segment
ROE	Return on Equity
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plans and non-qualified defined benefit retirement plans
SIP	Simplified Incentive Plan
SO_2	Sulfur dioxide
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company

NORTHEAST UTILITIES AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
WESTERN MASSACHUSETTS ELECTRIC COMPANY

2014 FORM 10-K ANNUAL REPORT

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NORTHEAST UTILITIES AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
WESTERN MASSACHUSETTS ELECTRIC COMPANY

SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

References in this Annual Report on Form 10-K to "NU," "the Company," "we," "our," and "us" refer to Northeast Utilities and its subsidiaries. Effective February 2, 2015, the Company began doing business as Eversource Energy.

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, future financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our forward-looking statements through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to:

- cyber breaches, acts of war or terrorism, or grid disturbances,
- actions or inaction of local, state and federal regulatory, public policy and taxing bodies,
- changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services, which could include disruptive technology related to our current or future business model,
- fluctuations in weather patterns,
- changes in laws, regulations or regulatory policy,
- changes in levels or timing of capital expenditures,
- disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly,
- developments in legal or public policy doctrines,
- technological developments,
- changes in accounting standards and financial reporting regulations,
- actions of rating agencies, and
- other presently unknown or unforeseen factors.

Other risk factors are detailed in our reports filed with the SEC and updated as necessary, and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all of such factors, nor can we assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A, *Risk Factors*, included in this combined Annual Report on Form 10-K. This Annual Report on Form 10-K also describes material contingencies and critical accounting policies in the accompanying *Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Combined Notes to Consolidated Financial Statements*. We encourage you to review these items.

NORTHEAST UTILITIES AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
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PART I

Item 1. Business

Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this combined Annual Report on Form 10-K.

On February 2, 2015, NU and each of its wholly owned utility subsidiaries listed below commenced doing business as Eversource Energy. NU, headquartered in Boston, Massachusetts and Hartford, Connecticut, is a public utility holding company subject to regulation by FERC under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly owned utility subsidiaries:

- The Connecticut Light and Power Company (CL&P), a regulated electric utility that serves residential, commercial and industrial customers in parts of Connecticut;
- NSTAR Electric Company (NSTAR Electric), a regulated electric utility that serves residential, commercial and industrial customers in parts of Massachusetts;
- Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire and owns generation assets used to serve customers;
- Western Massachusetts Electric Company (WMECO), a regulated electric utility that serves residential, commercial and industrial customers in parts of western Massachusetts and owns solar generating assets;
- NSTAR Gas Company (NSTAR Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Massachusetts; and
- Yankee Gas Services Company (Yankee Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut.

CL&P, NSTAR Electric, PSNH and WMECO also serve New England customers through NU's electric transmission business.

NU, CL&P, NSTAR Electric, PSNH and WMECO each report their financial results separately. We also include information in this report on a segment basis for NU. NU recognizes three reportable segments, which are electric distribution, electric transmission and natural gas distribution. NU's electric distribution segment includes the generation businesses of PSNH and WMECO. These three segments represented substantially all of NU's total consolidated revenues for the years ended December 31, 2014 and 2013. CL&P, NSTAR Electric, PSNH and WMECO do not report separate business segments.

ELECTRIC DISTRIBUTION SEGMENT

General

NU's electric distribution segment consists of the distribution businesses of CL&P, NSTAR Electric, PSNH and WMECO, which are engaged in the distribution of electricity to retail customers in Connecticut, eastern Massachusetts, New Hampshire and western Massachusetts, respectively, plus the regulated electric generation businesses of PSNH and WMECO.

The following table shows the sources of 2014 electric franchise retail revenues for NU's electric distribution companies, collectively, based on categories of customers:

(Thousands of Dollars, except percentages)	2014	% of Total
Residential	$ 3,288,313	53
Commercial	2,471,440	40
Industrial	348,698	6
Other and Eliminations	125,830	1
Total Retail Electric Revenues	$ 6,234,281	100%

A summary of our distribution companies' retail electric GWh sales volumes and percentage changes for 2014, as compared to 2013, is as follows:

	2014	2013	Percentage Change
Residential	21,317	21,896	(2.6)%
Commercial	27,449	27,787	(1.2)%
Industrial	5,676	5,648	0.5 %
Total	54,442	55,331	(1.6)%

Our 2014 consolidated retail electric sales volumes were lower, as compared to 2013, due primarily to cooler summer weather in 2014 as well as an increase in customer conservation efforts primarily by our residential customers, including the impact of energy efficiency programs sponsored by CL&P, NSTAR Electric and WMECO.

For WMECO and CL&P (effective December 1, 2014), fluctuations in retail electric sales volumes do not impact earnings due to the regulatory commission approved revenue decoupling mechanisms. Distribution revenues are decoupled from their customer sales volumes. CL&P and WMECO reconcile their annual base distribution rate recovery to pre-established levels of baseline distribution delivery service revenues. Any difference between the allowed level of distribution revenue and the actual amount incurred during a 12-month period is adjusted through rates in the following period. The decoupling mechanism effectively breaks the relationship between sales volumes and revenues recognized. Prior to December 1, 2014, CL&P recognized LBR related to reductions in sales volume as a result of successful energy efficiency programs. LBR was recovered from retail customers through the FMCC. Effective December 1, 2014, CL&P no longer recognizes LBR due to its revenue decoupling mechanism.

ELECTRIC DISTRIBUTION – CONNECTICUT

THE CONNECTICUT LIGHT AND POWER COMPANY

CL&P's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2014, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut, covering an area of 4,400 square miles. CL&P does not own any electric generation facilities.

The following table shows the sources of CL&P's 2014 electric franchise retail revenues based on categories of customers:

	CL&P	
(Thousands of Dollars, except percentages)	2014	% of Total
Residential	$ 1,474,181	58
Commercial	879,343	35
Industrial	149,220	6
Other	43,050	1
Total Retail Electric Revenues	$ 2,545,794	100%

A summary of CL&P's retail electric GWh sales volumes and percentage changes for 2014, as compared to 2013, is as follows:

	2014	2013	Percentage Change
Residential	10,026	10,314	(2.8)%
Commercial	9,643	9,770	(1.3)%
Industrial	2,377	2,320	2.5 %
Total	22,046	22,404	(1.6)%

Rates

CL&P is subject to regulation by PURA, which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service and construction and operation of facilities. CL&P's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. CL&P's retail rates include a delivery service component, which includes distribution, transmission, conservation, renewables, CTA, SBC and other charges that are assessed on all customers. Connecticut utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, in order to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under Connecticut law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains their electric distribution company. For those customers who do not choose a competitive energy supplier, under SS rates for customers with less than 500 kilowatts of demand, and LRS rates for customers with 500 kilowatts or more of demand, CL&P purchases power under standard offer contracts and passes the cost of the power to customers through a combined GSC and FMCC charge on customers' bills.

CL&P continues to supply approximately 45 percent of its customer load at SS or LRS rates while the other 55 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on CL&P's electric distribution business or its operating income.

The rates established by the PURA for CL&P are comprised of the following:

- An electric generation services charge (GSC), which recovers energy-related costs incurred as a result of providing electric generation service supply to all customers that have not migrated to competitive energy suppliers. The GSC is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

- A revenue decoupling adjustment (effective December 1, 2014) that reconciles the amounts recovered from customers, on an annual basis, to the distribution revenue requirement approved by the PURA in its last rate case, which currently is an annual amount of $1.041 billion.

- A distribution charge, which includes a fixed customer charge and a demand and/or energy charge to collect the costs of building and expanding the infrastructure to deliver power to its destination, as well as ongoing operating costs to maintain the infrastructure.

- A federally-mandated congestion charge (FMCC), which recovers any costs imposed by the FERC as part of the New England Standard Market Design, including locational marginal pricing, locational installed capacity payments, and any costs approved by PURA to reduce these charges. The FMCC also recovers costs associated with CL&P's system resiliency program. The FMCC is adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

- A transmission charge that recovers the cost of transporting electricity over high voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market.

- A competitive transition assessment charge (CTA), assessed to recover stranded costs associated with electric industry restructuring such as various IPP contracts. The CTA is reconciled annually to actual costs incurred and reviewed by PURA, with any difference refunded to, or recovered from, customers.

- A systems benefits charge (SBC), established to fund expenses associated with: various hardship and low income programs; a program to compensate municipalities for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring; and unfunded storage and disposal costs for spent nuclear fuel generated before 1983. The SBC is reconciled annually to actual costs incurred and reviewed by PURA, with any difference refunded to, or recovered from, customers.

- A Clean Energy Fund charge, which is used to promote investment in renewable energy sources. Amounts collected by this charge are deposited into the Clean Energy Fund and administered by the Clean Energy Finance and Investment Authority. The Clean Energy Fund charge is set by statute and is currently 0.1 cent per kWh.

- A conservation charge, comprised of a statutory rate established to implement cost-effective energy conservation programs and market transformation initiatives, plus a conservation adjustment mechanism charge to recover the residual energy efficiency spending associated with the expanded energy efficiency costs directed by the Comprehensive Energy Strategy Plan for Connecticut.

As required by regulation, CL&P, jointly with UI, entered into the following contracts whereby UI will share 20 percent and CL&P will share 80 percent of the costs and benefits (CL&P's portion of these costs are either recovered from, or refunded to, customers through the FMCC charge):

- Four CfDs (totaling approximately 787 MW of capacity) with three electric generation units and one demand response project, which extend through 2026 and have terms of up to 15 years beginning in 2009. The capacity CfDs obligate both CL&P and UI to make or receive payments on a monthly basis to or from the project and generation owners based on the difference between a set capacity price and the capacity market prices that the project and generation owners receive in the ISO-NE capacity markets.

- Three CfDs (totaling approximately 500 MW of peaking capacity) with three peaking generation units. The three peaker CfDs pay the generation owners the difference between capacity, forward reserve and energy market revenues and a cost-of service payment stream for 30 years (including costs of plant operation and the prices that the generation owners receive for capacity and other products in the ISO-NE markets.

- Long-term commitments to purchase approximately 250 MW of wind power from a Maine wind farm and 20 MW of solar power from a multi-site project in Connecticut. Both of these projects are expected to be operational by the end of 2016.

On December 17, 2014, PURA approved CL&P's application to amend customer rates, effective December 1, 2014, for a total distribution rate increase of $134 million, which includes an authorized ROE of 9.02 percent for the first twelve month period and 9.17 percent thereafter. The distribution rate increase included a revenue decoupling reconciliation mechanism effective December 1, 2014, and the recovery of 2011 and 2012 storm restoration costs and system resiliency costs. In addition, as part of the rate case, CL&P began recovering the 2013 storm costs and residual 2012 Storm Sandy costs over a seven-year period beginning December 1, 2014. As of December 31, 2014, all of CL&P's deferred storm costs have been addressed by regulatory proceedings.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy supply to serve its SS and LRS loads from a variety of competitive sources through requests for proposals. CL&P periodically enters into full requirements contracts for the majority of SS loads for periods of up to one year for its residential customers and small and medium commercial and industrial customers. CL&P is authorized to supply the remainder of the SS loads through a self-managed process that includes bilateral purchases and spot market purchases. CL&P typically enters into full requirements contracts for LRS for larger commercial and industrial customers every three months. Currently, CL&P has full requirements contracts

in place for 80 percent of its SS loads for the first half of 2015 and has bilateral purchases in place to self-manage the remaining 20 percent. For the second half of 2015, CL&P has 50 percent of its SS load under full requirements contracts, intends to purchase an additional 20 to 30 percent of full requirements and will self-manage the remainder as needed. None of the SS load for 2016 has been procured. CL&P has full requirements contracts in place for its LRS loads through the second quarter of 2015 and intends to purchase 100 percent of full requirements for the third and fourth quarters of 2015.

ELECTRIC DISTRIBUTION – MASSACHUSETTS

NSTAR ELECTRIC COMPANY
WESTERN MASSACHUSETTS ELECTRIC COMPANY

The electric distribution businesses of NSTAR Electric and WMECO consist primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers within their respective franchise service territories. As of December 31, 2014, NSTAR Electric furnished retail franchise electric service to approximately 1.2 million customers in Boston and 80 surrounding cities and towns in Massachusetts, including Cape Cod and Martha's Vineyard, covering an area of approximately 1,700 square miles. WMECO provides retail franchise electric service to approximately 208,000 customers in 59 cities and towns in the western region of Massachusetts, covering an area of approximately 1,500 square miles. Neither NSTAR Electric nor WMECO owns any coal-fired, oil-fired, or hydro-electric generating facilities, and each purchases its respective energy requirements from competitive energy suppliers.

In 2009, WMECO was authorized by the DPU to install solar energy generation in its service territory. From 2010 through 2014, WMECO completed development of a total of 8 MW solar generation facilities on sites in Pittsfield, Springfield, and East Springfield, Massachusetts. WMECO will sell all energy and other products from its solar generation facilities into the ISO-NE market. NSTAR Electric does not own any solar generation facilities.

The following table shows the sources of the 2014 electric franchise retail revenues of NSTAR Electric and WMECO based on categories of customers:

(Thousands of Dollars, except percentages)	NSTAR Electric		WMECO	
	2014	% of Total	2014	% of Total
Residential	$ 1,101,704	46	$ 233,675	56
Commercial	1,161,466	49	131,093	31
Industrial	89,643	4	37,211	9
Other	29,765	1	15,470	4
Total Retail Electric Revenues	$ 2,382,578	100%	$ 417,449	100%

A summary of NSTAR Electric's and WMECO's retail electric GWh sales volumes and percentage changes for 2014, as compared to 2013, is as follows:

	NSTAR Electric			WMECO		
	2014	2013	Percentage Change	2014	2013	Percentage Change
Residential	6,625	6,831	(3.0)%	1,494	1,544	(3.2)%
Commercial	13,009	13,163	(1.2)%	1,466	1,496	(2.0)%
Industrial	1,291	1,312	(1.6)%	626	643	(2.5)%
Total	20,925	21,306	(1.8)%	3,586	3,683	(2.6)%

Rates

NSTAR Electric and WMECO are each subject to regulation by the DPU, which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, acquisition of securities, standards of service and construction and operation of facilities. The present general rate structure for both NSTAR Electric and WMECO consists of various rate and service classifications covering residential, commercial and industrial services. Massachusetts utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, in order to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under Massachusetts law, all customers of each of NSTAR Electric and WMECO are entitled to choose their energy suppliers, while NSTAR Electric or WMECO remains their electric distribution company. Both NSTAR Electric and WMECO purchase power from competitive suppliers on behalf of, and pass the related cost through to, their respective customers who do not choose a competitive energy supplier (basic service). Most of the residential and small commercial and industrial customers of NSTAR Electric and WMECO have continued to buy their power from NSTAR Electric or WMECO at basic service rates. Most large commercial and industrial customers have switched to a competitive energy supplier.

The Cape Light Compact, an inter-governmental organization consisting of the 21 towns and two counties on Cape Cod and Martha's Vineyard, serves 200,000 customers through the delivery of energy efficiency programs, effective consumer advocacy, competitive electricity supply and green power options. NSTAR Electric continues to provide electric service to these customers including the delivery of power, maintenance of infrastructure, capital investment, meter reading, billing, and customer service.

NSTAR Electric continues to supply approximately 44 percent of its customer load at basic service rates while the other 56 percent of its customer load has migrated to competitive energy suppliers. WMECO continues to supply approximately 51 percent of its customer load at basic service rates

while the other 49 percent of its customer load has migrated to competitive energy suppliers. Because customer migration is limited to energy supply service, it has no impact on the delivery business or operating income of NSTAR and WMECO.

The rates established by the DPU for NSTAR Electric and WMECO are comprised of the following:

- A basic service charge that represents the collection of energy costs, including costs related to charge-offs of uncollected energy costs from customers. Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through basic service for those who choose not to buy energy from a competitive energy supplier. Basic service rates are reset every six months (every three months for large commercial and industrial customers). Additionally, the DPU has authorized NSTAR Electric to recover the cost of its Dynamic Pricing Smart Grid Pilot Program through the basic service charge. Basic service costs are reconciled annually.

- A distribution charge, which includes a fixed customer charge and a demand and/or energy charge to collect the costs of building and expanding the infrastructure to deliver power to its destination, as well as ongoing operating costs.

- For WMECO, a revenue decoupling adjustment that reconciles distribution revenue, on an annual basis, to the amount of distribution revenue approved by the DPU in its last rate case in 2011. Currently, WMECO is allowed to collect $132.4 million annually.

- A transmission charge that recovers the cost of transporting electricity over high voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market.

- A transition charge that represents costs to be collected primarily from previously held investments in generating plants, costs related to existing above-market power contracts, and contract costs related to long-term power contract buy-outs.

- An energy efficiency charge that represents a legislatively-mandated charge to collect costs for energy efficiency programs.

- Reconciling adjustment charges that recover certain DPU-approved costs as follows: pension and PBOP benefits, low income customer discounts, lost revenue and credits associated with net-metering facilities installed by customers, storms, consultants retained by the attorney general, and energy efficiency programs and lost base revenue not recovered in the energy efficiency charge. In addition to these adjustments common to both NSTAR Electric and WMECO, NSTAR Electric has reconciling adjustment charges that collect costs associated with certain safety and reliability projects, a Smart Grid pilot program, and long-term renewable contracts. WMECO has a reconciling adjustment charge that recovers costs associated with certain solar projects owned and operated by WMECO.

As required by regulation, NSTAR Electric and WMECO, along with two other Massachusetts electric utilities, signed long-term commitments to purchase a combined estimated generating capacity of approximately 334 MW of wind power from two wind farms in Maine over 15 years. The projects are in various stages of permitting or development and are expected to begin operation in 2015 and 2016.

Pursuant to a 2008 DPU order, Massachusetts electric utilities must adopt rate structures that decouple the volume of energy sales from the utility's revenues in their next rate case. WMECO is currently decoupled and NSTAR Electric will propose decoupling in its next rate case.

NSTAR Electric and WMECO are each subject to service quality (SQ) metrics that measure safety, reliability and customer service, and could be required to pay to customers a SQ charge of up to 2.5 percent of annual transmission and distribution revenues for failing to meet such metrics. Neither NSTAR Electric nor WMECO will be required to pay a SQ charge for its 2014 performance as each company achieved results at or above target for all of its respective SQ metrics in 2014.

Sources and Availability of Electric Power Supply

As noted above, neither NSTAR Electric nor WMECO owns any generation assets (other than WMECO's solar generation), and both companies purchase their respective energy requirements from a variety of competitive sources through requests for proposals issued periodically, consistent with DPU regulations. NSTAR Electric and WMECO enter into supply contracts for basic service for 50 percent of their respective residential and small commercial and industrial customers twice per year for twelve month terms. Both NSTAR Electric and WMECO enter into supply contracts for basic service for 100 percent of large commercial and industrial customers every three months.

ELECTRIC DISTRIBUTION – NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PSNH's distribution business consists primarily of the generation, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2014, PSNH furnished retail franchise electric service to approximately 504,000 retail customers in 211 cities and towns in New Hampshire, covering an area of approximately 5,630 square miles. PSNH also owns and operates approximately 1,200 MW of primarily coal- and oil-fired electricity generation plants. PSNH's distribution business includes the activities of its generation business.

The Clean Air Project, a wet flue gas desulphurization system (Scrubber), was constructed and placed in service by PSNH at its Merrimack Station in 2011. Tests to date indicate that the Scrubber reduces emissions of SO_2 and mercury from Merrimack Station by over 90 percent, which is well in excess of state and federal requirements. PSNH is permitted to recover prudent Scrubber costs through its ES rates under New Hampshire law. In 2011, the NHPUC opened a docket to review the Clean Air Project. For further information, see "Regulatory Developments and Rate Matters – New Hampshire – Clean Air Project Prudence Proceeding" in the accompanying Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

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The following table shows the sources of PSNH's 2014 electric franchise retail revenues based on categories of customers:

(Thousands of Dollars, except percentages)	PSNH 2014	% of Total
Residential	$ 478,753	54
Commercial	299,538	34
Industrial	72,624	8
Other	37,544	4
Total Retail Electric Revenues	$ 888,459	100%

A summary of PSNH's retail electric GWh sales volumes and percentage changes for 2014, as compared to 2013, is as follows:

	2014	2013	Percentage Change
Residential	3,172	3,208	(1.1)%
Commercial	3,332	3,357	(0.8)%
Industrial	1,382	1,373	0.6 %
Total	7,886	7,938	(0.7)%

Rates

PSNH is subject to regulation by the NHPUC, which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service and construction and operation of facilities. New Hampshire utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, in order to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under New Hampshire law, all of PSNH's customers are entitled to choose competitive energy suppliers, with PSNH providing default energy service under its ES rate for those customers who do not choose a competitive energy supplier. At the end of 2014, approximately 21 percent of all of PSNH's customers (approximately 46 percent of load) were taking service from competitive energy suppliers, compared to 25 percent of customers (approximately 54 percent of load) at the end of 2013.

The rates established by the NHPUC for PSNH are comprised of the following:

- A default energy service charge (ES) is charged to customers who have selected not to receive their energy supply from a competitive energy supplier. These charges recover the costs of PSNH's generation, as well as purchased power, and include the NHPUC allowed ROE of 9.81 percent on PSNH's generation investment.

- A distribution charge, which includes an energy and/or demand-based charge to recover costs related to the maintenance and operation of PSNH's infrastructure to deliver power to its destination, as well as power restoration and service costs. This includes a customer charge to collect the cost of providing service to a customer; such as the installation, maintenance, reading and replacement of meters and maintaining accounts and records.

- A transmission charge that recovers the cost of transporting electricity over high voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market.

- A stranded cost recovery charge (SCRC), which allows PSNH to recover its stranded costs, including above-market expenses incurred under mandated power purchase obligations and other long-term investments and obligations. PSNH had financed a significant portion of its stranded costs through securitization by issuing RRBs secured by the right to recover these stranded costs from customers over the life of the RRBs. The costs of the RRBs, which were retired on May 1, 2013, were recovered through the SCRC rate.

- A systems benefits charge (SBC), which funds energy efficiency programs for all customers as well as assistance programs for residential customers within certain income guidelines.

- An electricity consumption tax, which is a state mandated tax on energy consumption.

The energy charge and SCRC rates change semi-annually and are reconciled annually and recovered in subsequent rates. The Rate ADE reconciliation amount is incorporated into the ES reconciliation.

PSNH is currently operating under the 2010 NHPUC approved distribution rate case settlement, which is effective through June 30, 2015. Under the settlement, PSNH is permitted to file a request to collect certain exogenous costs and step increases on an annual basis.

Generation Assets

In 2013, the NHPUC opened a docket that initiated a series of actions throughout 2013 and 2014 regarding the potential divestiture of PSNH's generating plants, including actions by the NHPUC staff, the State of New Hampshire Legislative Oversight Committee on Electric Utility Restructuring (Oversight Committee), a valuation expert, and the New Hampshire Legislature. During the 2014 Legislative session, in response to an NHPUC staff recommendation to harmonize existing laws regarding divestiture, energy service, and cost recovery, the Legislature enacted changes to the laws governing divestiture of PSNH's generation assets, effective September 30, 2014. The new law required the NHPUC to initiate a

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proceeding before January 1, 2015, to determine whether all or some of PSNH's generation assets should be divested. The NHPUC opened its docket DE 14-238 on September 16, 2014. A progress report from the NHPUC must be provided to the Oversight Committee by March 31, 2015. The law gives the NHPUC express authority to order the divestiture of all or some of PSNH's generation assets if the NHPUC finds it is in the economic interest of customers to do so. The law also clarified the definition of "stranded costs" to include costs approved for recovery by the NHPUC in connection with the divestiture or retirement of PSNH's generation assets. In the event of generation asset divestiture or retirement, present law and the PSNH Restructuring Settlement Agreement approved in 2000 require that the NHPUC provide recovery of any stranded costs by PSNH. For further information, see "Regulatory Developments and Rate Matters – New Hampshire - Generation" in the accompanying Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Sources and Availability of Electric Power Supply

During 2014, approximately 59 percent of PSNH's load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with competitive energy suppliers. The remaining 41 percent of PSNH's load was met by short-term (less than one year) purchases and spot purchases in the competitive New England wholesale power market. PSNH expects to meet its load requirements in 2015 in a similar manner. Included in the 59 percent above are PSNH's obligations to purchase power from approximately two dozen IPPs, the output of which it either uses to serve its customer load or sells into the ISO-NE market.

Merrimack, Schiller and the Hydro stations have been operating at very high capacity factors during this current winter season. As a result of our diverse fuel mix, PSNH's Energy Service rate has been set at 10.56 cents per kWh, well below the winter default service rates in excess of 15 cents per kWh for the two other investor owned utilities in the state.

MAJOR STORMS

CL&P, NSTAR Electric, PSNH and WMECO experienced several significant storm events, including Tropical Storm Irene in 2011, the October 2011 snowstorm, Storm Sandy in 2012, the February 2013 blizzard, and a November 2014 snowstorm. As a result of these storm events, each company suffered extensive damage to its distribution and transmission systems resulting in customer outages. Each company incurred significant costs to repair damage and restore customers' service.

The magnitude of these storm restoration costs met the criteria for cost deferral in Connecticut, Massachusetts, and New Hampshire. As a result, the storms had no material impact on the results of operations of CL&P, NSTAR Electric, PSNH and WMECO. We believe the storm restoration costs were prudent and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery process. Each electric utility has sought, or is seeking, recovery of its deferred storm restoration costs through its applicable regulatory recovery process. For further information, see "Regulatory Developments and Rate Matters" in the accompanying Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

ELECTRIC TRANSMISSION SEGMENT

General

Each of CL&P, NSTAR Electric, PSNH and WMECO owns and maintains transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. Each of CL&P, NSTAR Electric, PSNH and WMECO, and most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent of all market participants, serves as the regional transmission organization of the New England transmission system.

Wholesale Transmission Revenues

A summary of NU's wholesale transmission revenues is as follows:

(Thousands of Dollars)		2014
CL&P	$	507,182
NSTAR Electric		275,377
PSNH		114,963
WMECO		120,803
Total Wholesale Transmission Revenues	$	1,018,325

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through FERC approved formula rates. Transmission revenues are collected from New England customers, the majority of which are distribution customers of CL&P, NSTAR Electric, PSNH and WMECO. The transmission rates provide for the annual reconciliation of estimated to actual costs. The financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refunded to, transmission customers.

FERC Base ROE Complaints

Beginning in 2011, several New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (the "Complainants") jointly filed three separate complaints at FERC. In the first complaint, filed in 2011, the Complainants alleged that the NETOs' base ROE of 11.14 percent that was utilized since 2006 was unjust and unreasonable, asserted that the rate was excessive due to changes in the capital markets, and sought an order to reduce it prospectively from the date of the final FERC order and for the 15-month period beginning October 1, 2011 to December 31, 2012 (the "first complaint refund period"). In the pursuant second and third complaints, filed in 2012 and 2014, respectively, the Complainants challenged the NETOs' base ROE and sought refunds for the 15-month periods beginning December 27, 2012 and July 31, 2014, respectively.

In 2014, the FERC determined that the base ROE should be set at 10.57 percent for the first complaint refund period and that a utility's total or maximum ROE should not exceed the top of the new zone of reasonableness (7.03 percent to 11.74 percent). The FERC ordered the NETOs to provide refunds to customers for the first complaint refund period and set the new base ROE of 10.57 percent prospectively from October 16, 2014. In late 2014, the NETOs made a compliance filing, and began refunding amounts from the first complaint period, inclusive of incentive ROE adders that exceeded the 11.74 percent as compared to the total company transmission ROE. Complainants have challenged the compliance filing.

As a result of the actions taken by the FERC and other developments in this matter, NU recorded reserves in 2013 and 2014 to recognize the potential financial impacts of the first and second complaints. The Company is unable to determine any amount related to the third complaint. The aggregate after-tax net charge to 2014 earnings resulting from the 2014 FERC orders totaled $22.4 million at NU. In 2013, the aggregate after-tax charge to earnings totaled $14.3 million at NU.

Although management is uncertain on the final outcome on the second and third complaints regarding the base ROE and the incentive ROE adder, management believes the current reserves established are appropriate to reflect probable and reasonably estimable refunds. For further information, see "FERC Regulatory Issues – FERC Base ROE Complaints" in the accompanying Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

FERC Order No. 1000

On August 15, 2014, the D.C. Circuit Court of Appeals upheld FERC's authority to order major changes to transmission planning and cost allocation in FERC Order No. 1000 and Order No. 1000-A, including transmission planning for public policy needs, and the requirement that utilities remove from their transmission tariffs their rights of first refusal to build transmission. FERC has not yet ruled on the comprehensive compliance filings made in November 2013 by the NETOs, including CL&P, NSTAR Electric, PSNH and WMECO. We cannot predict the final outcome or impact on us; however, implementation of FERC's goals in New England, including within our service territories, may expose us to competition for construction of transmission projects, additional regulatory considerations, and potential delay with respect to future transmission projects. While the FERC Orders may bring new challenges, we believe there are also opportunities for us to compete for transmission reliability projects outside of our service territories.

Transmission Projects

During 2014, we were involved in the planning, development and construction of a series of transmission projects, including the NEEWS family of projects, Northern Pass, which is NU's planned HVDC transmission line from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire, and Greater Boston Reliability Solutions, which are a series of new transmission projects over the next five years that will enhance system reliability and improve capacity. For further information, see "Business Development and Capital Expenditures – Transmission Business" in the accompanying Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Transmission Rate Base

Under our FERC-approved tariff, and with the exception of transmission projects that received specific FERC approval to include CWIP in rate base, transmission projects generally enter rate base after they are placed in commercial operation. At the end of 2014, our estimated transmission rate base was approximately $4.9 billion, including approximately $2.4 billion at CL&P, $1.3 billion at NSTAR Electric, $535 million at PSNH, and $611 million at WMECO.

NATURAL GAS DISTRIBUTION SEGMENT

NSTAR Gas distributes natural gas to approximately 282,000 customers in 51 communities in central and eastern Massachusetts covering 1,067 square miles and Yankee Gas distributes natural gas to approximately 222,000 customers in 71 cities and towns in Connecticut covering 2,187 square miles. Total throughput (sales and transportation) in 2014 was approximately 60.5 Bcf for NSTAR Gas and 55 Bcf for Yankee Gas. Our natural gas businesses provide firm natural gas sales service to retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on natural gas for heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase natural gas from NU's natural gas distribution companies. A portion of the storage of natural gas supply for NSTAR Gas during the winter heating season is provided by Hopkinton LNG Corp., an indirect, wholly-owned subsidiary of NU. The facilities consist of an LNG liquefaction and vaporization plant and three above-ground cryogenic storage tanks in Hopkinton, Massachusetts having an aggregate capacity of 3.0 Bcf of liquefied natural gas. NSTAR Gas also has access to facilities in Acushnet, Massachusetts that include additional storage capacity of 0.5 Bcf and additional vaporization capacity. Yankee Gas owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which is used primarily to assist Yankee Gas in meeting its supplier-of-last-resort obligations and also enables it to provide economic supply and make economic refill of natural gas typically during periods of low demand.

NSTAR Gas and Yankee Gas generate revenues primarily through the sale and/or transportation of natural gas. Predominantly all residential customers in the NSTAR Gas service territory buy gas supply and delivery from NSTAR Gas while all customers may choose their gas suppliers. Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas' service territory buy natural gas supply and delivery only from Yankee Gas while commercial and industrial customers may choose their natural gas suppliers. NSTAR Gas offers firm transportation service to all customers who purchase gas from sources other than NSTAR Gas while Yankee Gas offers firm transportation service to its commercial and industrial customers who purchase natural gas from sources other than Yankee Gas. In addition, both natural gas distribution companies offer interruptible transportation and interruptible natural gas sales service to those high volume commercial and industrial customers, generally during the colder months, that have the capability to switch from natural gas to an alternative fuel on short notice, for whom NSTAR Gas and Yankee Gas can interrupt service during peak demand periods or at any other time to maintain distribution system integrity.

The following table shows the sources of the 2014 total NU natural gas franchise retail revenues based on categories of customers:

(Thousands of Dollars, except percentages)		2014	% of Total
Residential	$	520,410	55
Commercial		332,414	35
Industrial		94,861	10
Total Retail Natural Gas Revenues	$	947,685	100%

A summary of our firm natural gas sales volumes in million cubic feet and percentage changes for 2014, as compared to 2013, is as follows:

	2014	2013	Percentage Change
Residential	38,969	36,777	6.0%
Commercial	42,977	40,215	6.9%
Industrial	22,245	21,266	4.6%
Total	104,191	98,258	6.0%
Total, Net of Special Contracts [(1)]	99,500	94,083	5.8%

(1) Special contracts are unique to the customers who take service under such an arrangement and generally specify the amount of distribution revenue to be paid to Yankee Gas regardless of the customers' usage.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales. In addition, they have benefited from favorable natural gas prices and customer growth across both operating companies. Our 2014 consolidated firm natural gas sales volumes, consisting of the firm natural gas sales volumes of Yankee Gas and NSTAR Gas, were higher, as compared to 2013, due primarily to colder weather in the first quarter of 2014, as compared to the same period in 2013, and increased customer growth in 2014, as compared to 2013. Weather-normalized NU consolidated firm natural gas sales volumes increased 2.9 percent in 2014, as compared to 2013.

Rates

NSTAR Gas and Yankee Gas are subject to regulation by the DPU and PURA, respectively, which, among other things, have jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service and construction and operation of facilities. Both of NU's natural gas companies are entitled under their respective state law to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, in order to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Retail natural gas delivery and supply rates are established by the DPU and PURA and are comprised of:

- A distribution charge consisting of a fixed customer charge and a demand and/or energy charge that collects the costs of building and expanding the natural gas infrastructure to deliver natural gas supply to its customers. This also includes collection of ongoing operating costs;

- A seasonal cost of gas adjustment clause (CGAC) at NSTAR Gas that collects natural gas supply costs, pipeline and storage capacity costs, costs related to charge-offs of uncollected energy costs and working capital related costs. The CGAC is reset semi-annually. In addition,

NSTAR Gas files interim changes to its CGAC factor when the actual costs of natural gas supply vary from projections by more than five percent; and

- A local distribution adjustment clause (LDAC) at NSTAR Gas that collects energy efficiency program costs, environmental costs, pension and PBOP related costs, energy efficiency costs, attorney general consultant costs, and costs associated with low income customers. The LDAC is reset annually and provides for the recovery of certain costs applicable to both sales and transportation customers.

- Purchased Gas Adjustment (PGA) clause, which allows Yankee Gas to recover the costs of the procurement of natural gas for its firm and seasonal customers. Differences between actual natural gas costs and collection amounts on August 31st of each year are deferred and then recovered from or refunded to customers during the following year. Carrying charges on outstanding balances are calculated using Yankee Gas' weighted average cost of capital in accordance with the directives of the PURA; and

- Conservation Adjustment Mechanism (CAM) at Yankee Gas, which allows 100 percent recovery of conservation costs through this mechanism including program incentives to promote energy efficiency, as well as recovery of any lost revenues associated with implementation of energy conservation measures. A reconciliation of CAM revenues to expenses is performed annually with any difference being recovered from or refunded to customers, with carrying charges, during the following year.

NSTAR Gas purchases financial contracts based on NYMEX natural gas futures in order to reduce cash flow variability associated with the purchase price for approximately one-third of its natural gas purchases. These purchases are made under a program approved by the DPU in 2006. This practice attempts to minimize the impact of fluctuations in natural gas prices to NSTAR Gas' firm natural gas customers. These financial contracts do not procure natural gas supply. All costs incurred or benefits realized when these contracts are settled are included in the CGAC.

NSTAR Gas is subject to SQ metrics that measure safety, reliability and customer service and could be required to pay to customers a SQ charge of up to 2.5 percent of annual distribution revenues for failing to meet such metrics. NSTAR Gas will not be required to pay a SQ charge for its 2014 performance as it achieved results at or above target for all of its SQ metrics in 2014.

On December 17, 2014, NSTAR Gas filed an application with the DPU requesting an increase in rates, effective January 1, 2016. NSTAR Gas requested an increase in base distribution rates of $33.9 million. Based on the current schedule, we expect a final decision in the fourth quarter of 2015.

In 2011, PURA approved Yankee Gas' rate proceeding. The final decision approved a regulatory ROE of 8.83 percent and allowed for a substantial increase in annual spending for bare steel and cast iron pipeline replacement.

Massachusetts Natural Gas Replacement and Expansion

On July 7, 2014, Massachusetts enacted "An Act Relative to Natural Gas Leaks" (the Act). The Act establishes a uniform natural gas leak classification standard for all Massachusetts natural gas utilities and a program that accelerates the replacement of aging natural gas infrastructure. The program will enable companies, including NSTAR Gas, to better manage the scheduling and costs of replacement. The Act also calls for the DPU to authorize natural gas utilities to design and offer programs to customers that will increase the availability, affordability and feasibility of natural gas service for new customers.

NSTAR Gas filed the Gas System Enhancement Program (GSEP) with the DPU on October 31, 2014. NSTAR Gas' program accelerates the replacement of certain natural gas distribution facilities in the system within 25 years. The GSEP includes a new tariff that provides NSTAR Gas an opportunity to collect the costs for the program on an annual basis through a newly designed reconciling factor to be approved by the DPU. We expect a decision on the program in April 2015.

Connecticut Natural Gas Expansion Plan

In 2013, in accordance with Connecticut law and regulation, PURA approved a comprehensive joint natural gas infrastructure expansion plan (expansion plan) filed by Yankee Gas and other Connecticut natural gas distribution companies. The expansion plan described how Yankee Gas expects to add approximately 82,000 new natural gas heating customers over the next 10 years. Yankee Gas estimates that its portion of the plan will cost approximately $700 million over 10 years. In January 2015, PURA approved a joint settlement agreement proposed by Yankee Gas and other Connecticut natural gas distribution companies and regulatory agencies that clarified the procedures and oversight criteria applicable to the expansion plan.

Sources and Availability of Natural Gas Supply

NSTAR Gas maintains a flexible resource portfolio consisting of natural gas supply contracts, transportation contracts on interstate pipelines, market area storage and peaking services. NSTAR Gas purchases transportation, storage, and balancing services from Tennessee Gas Pipeline Company and Algonquin Gas Transmission Company, as well as other upstream pipelines that transport gas from major producing regions in the U.S., including the Gulf Coast, Mid-continent region, and Appalachian Shale supplies to the final delivery points in the NSTAR Gas service area. NSTAR Gas purchases all of its natural gas supply under a firm portfolio management contract with a term of one year, which has a maximum quantity of approximately 154,700 MMBtu/day of firm flowing natural gas supplies and 76,700 MMBtu/day of firm natural gas storage supplies.

In addition to the firm transportation and natural gas supplies mentioned above, NSTAR Gas utilizes contracts for underground storage and LNG facilities to meet its winter peaking demands. The LNG facilities, described below, are located within NSTAR Gas' distribution system and are used to liquefy and store pipeline natural gas during the warmer months for vaporization and use during the heating season. During the summer injection season, excess pipeline capacity and supplies are used to deliver and store natural gas in market area underground storage facilities located in the

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New York and Pennsylvania regions. Stored natural gas is withdrawn during the winter season to supplement flowing pipeline supplies in order to meet firm heating demand. NSTAR Gas has firm underground storage contracts and total storage capacity entitlements of approximately 6.6 Bcf.

A portion of the storage of natural gas supply for NSTAR Gas during the winter heating season is provided by Hopkinton LNG Corp., which owns an LNG liquefaction and vaporization plant and three above-ground cryogenic storage tanks having an aggregate capacity of 3.0 Bcf of liquefied natural gas. NSTAR Gas also has access to facilities that include additional storage capacity of 0.5 Bcf and additional vaporization capacity.

PURA requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its supply portfolio to meet firm customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas' on-system stored LNG and underground storage supplies help to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate capacity from the three interstate pipelines that directly serve Connecticut: the Algonquin, Tennessee and Iroquois Pipelines. Yankee Gas has long-term firm contracts for capacity on TransCanada Pipelines Limited Pipeline, Vector Pipeline, L.P., Tennessee Gas Pipeline, Iroquois Gas Transmission Pipeline, Algonquin Pipeline, Union Gas Limited, Dominion Transmission, Inc., National Fuel Gas Supply Corporation, Transcontinental Gas Pipeline Company, and Texas Eastern Transmission, L.P. pipelines.

Based on information currently available regarding projected growth in demand and estimates of availability of future supplies of pipeline natural gas, NSTAR Gas and Yankee Gas each believes that participation in planned and anticipated pipeline expansion projects will be required in order for it to meet current and future sales growth opportunities.

NATURAL GAS PIPELINE EXPANSION

On September 16, 2014, NU and Spectra Energy Corp announced Access Northeast, a natural gas pipeline expansion project. Access Northeast will enhance the Algonquin and Maritimes pipeline systems using existing routes and is expected to be capable of delivering approximately one billion cubic feet of natural gas per day to New England. NU and Spectra Energy Corp will have equal ownership interest in the project with the option of additional investors joining in the future. On February 18, 2015, NU, Spectra Energy Corp and National Grid announced the addition of National Grid as a co-developer in the project for a total ownership interest of 20 percent, with NU and Spectra Energy Corp each owning 40 percent. The total project cost, subject to FERC approval, is expected to be approximately $3 billion and has an anticipated in-service date of November 2018.

On December 8, 2014, NU and Spectra Energy Corp announced an alliance with Iroquois Gas Transmission for the Access Northeast project. This alliance will provide New England natural gas distribution companies and generators with additional access to natural gas supplies from multiple, diverse receipt points along the Algonquin pipeline system, including the Iroquois pipeline system.

PROJECTED CAPITAL EXPENDITURES

We project to make capital expenditures of approximately $8.4 billion from 2015 through 2018. Of the $8.4 billion, we expect to invest approximately $4.2 billion in our electric and natural gas distribution segments and $3.9 billion in our electric transmission segment. In addition, we project to invest approximately $360 million in information technology and facilities upgrades and enhancements. These projections do not include capital expenditures related to Access Northeast.

FINANCING

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All of these companies currently are, and expect to remain, in compliance with these covenants.

As of December 31, 2014, a total of $216.7 million of NU's long-term debt will be paid in the next 12 months, consisting of $162 million for CL&P, $4.7 million for NSTAR Electric and $50 million or WMECO.

NUCLEAR FUEL STORAGE

CL&P, NSTAR Electric, PSNH, WMECO and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective generation facilities and are now engaged in the long-term storage of their spent nuclear fuel. Each Yankee Company has completed its collection of decommissioning and closure costs through the proceeds from the spent nuclear fuel litigation against the DOE. These proceeds were used by the Yankee Companies to offset the decommissioning and closure cost receivables from their member companies or to decrease the wholesale FERC-approved rates charged under power purchase agreements with CL&P, NSTAR Electric, PSNH and WMECO and several other New England utilities. The decommissioning rates charged by the Yankee Companies have been eliminated. CL&P, NSTAR Electric, PSNH and WMECO can recover these costs from, or refund proceeds to, their customers through state regulatory commission-approved retail rates.

As a result of the merger with NSTAR, we consolidate the assets and obligations of CYAPC and YAEC on our consolidated balance sheet.

For information on the DOE proceeds received related to the spent nuclear fuel litigation, see Note 11C, "Commitments and Contingencies – Contractual Obligations – Yankee Companies," in the accompanying Item 8, *Financial Statements and Supplementary Data*.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including FERC, the SEC, and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each of our companies operates, including the PURA, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has jurisdiction over NSTAR Electric, NSTAR Gas and WMECO.

Environmental Regulation

We are subject to various federal, state and local requirements with respect to water quality, air quality, toxic substances, hazardous waste and other environmental matters. Additionally, major generation and transmission facilities may not be constructed or significantly modified without a review of the environmental impact of the proposed construction or modification by the applicable federal or state agencies.

Water Quality Requirements

The Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the EPA or state environmental agency specifying the allowable quantity and characteristics of its effluent. States may also require additional permits for discharges into state waters. We are in the process of maintaining or renewing all required NPDES or state discharge permits in effect for PSNH's generation facilities.

In 1997, PSNH filed in a timely manner for a renewal of the NPDES permit for the Merrimack Station. As a result, the existing permit was administratively continued. In 2011, the EPA issued a draft renewal NPDES permit for PSNH's Merrimack Station for public review and comment. The proposed permit contains many significant conditions to future operation. The proposed permit would require PSNH to install a closed-cycle cooling system (including cooling towers) at the station. The EPA estimated that the net present value cost to install this system and operate it over a 20-year period would be approximately $112 million. PSNH and other electric utility groups filed thousands of pages of comments contesting EPA's draft permit requirements. PSNH stated that the data and studies supplied to the EPA demonstrate the fact that a closed-cycle cooling system is not warranted. On April 18, 2014 EPA issued a revised section of the draft NPDES permit for Merrimack Station. The revised portion of the draft permit deals solely with the treatment of wastewater from the flue gas desulfurization system. On August 18, 2014 PSNH again submitted comments. The EPA does not have a set deadline to consider comments and to issue a final permit. Merrimack Station is permitted to continue to operate under its present permit pending issuance of the final permit and subsequent resolution of matters appealed by PSNH and other parties. Due to the site specific characteristics of PSNH's other coal- and oil-fired electric generating stations, we believe it is unlikely that they would face similar permitting determinations.

Air Quality Requirements

The Clean Air Act Amendments (CAAA), as well as New Hampshire law, impose stringent requirements on emissions of SO_2 and NO_X for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Requirements for the installation of continuous emissions monitors and expanded permitting provisions also are included.

In 2011, the EPA finalized the Mercury and Air Toxic Standards (MATS) that require the reduction of emissions of hazardous air pollutants from new and existing coal- and oil-fired electric generating stations. Previously referred to as the Utility MACT (maximum achievable control technology) rules, it establishes emission limits for mercury, arsenic and other hazardous air pollutants from coal- and oil-fired electric generating stations. MATS is the first implementation of a nationwide emissions standard for hazardous air pollutants across all electric generating units and provides utility companies with up to five years to meet the requirements. PSNH owns and operates approximately 1,000 MW of coal- and oil-fired electric generating stations subject to MATS, including the two units at Merrimack Station, Newington Station and the two coal units at Schiller Station. We believe the Clean Air Project at our Merrimack Station, together with existing equipment, will enable the facility to meet the MATS requirements. At Schiller Station additional controls are being installed at the two coal-fired units, the cost of which is estimated to be approximately $2.5 million.

Each of the states in which we do business also has Renewable Portfolio Standards (RPS) requirements, which generally require fixed percentages of our energy supply to come from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources.

New Hampshire's RPS provision requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2014, the total RPS obligation was 9.7 percent and it will ultimately reach 24.8 percent in 2025. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses a portion of internally generated RECs to meet its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes up the difference between the RECs purchased and its total obligation by making an alternative compliance payment for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments are recovered by PSNH through its ES rates charged to customers.

The RECs generated from PSNH's Northern Wood Power Project, a wood-burning facility, are typically sold to other energy suppliers or load carrying entities, and the net proceeds from the sale of these RECs are credited back to customers.

Similarly, Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2014, the total RPS obligation was 18 percent and will ultimately reach 27 percent in 2020. CL&P is permitted to recover any costs incurred in complying with RPS from its customers through its GSC rate.

Massachusetts' RPS program also requires electricity suppliers to meet renewable energy standards. For 2014, the requirement was 16.1 percent, and will ultimately reach 22.1 percent in 2020. NSTAR Electric and WMECO are permitted to recover any costs incurred in complying with RPS from its customers through rates. WMECO also owns renewable solar generation resources. The RECs generated from WMECO's solar units are sold to other energy suppliers, and the proceeds from these sales are credited back to customers.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century, when environmental best practices laws and regulations were implemented, utility companies often disposed of residues from operations by depositing or burying them on-site or disposing of them at off-site landfills or other facilities. Typical materials disposed of include coal gasification byproducts, fuel oils, ash, and other materials that might contain polychlorinated biphenyls or that otherwise might be hazardous. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. We have recorded a liability for what we believe, based upon currently available information, is our reasonably estimable environmental investigation and/or remediation costs for waste disposal sites for which we have probable liability. We continue to evaluate the environmental impact of our former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on us for these practices. As of December 31, 2014, the liability recorded for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $43.3 million, representing 65 sites. These costs could be significantly higher if remediation becomes necessary or when additional information as to the extent of contamination becomes available.

The most significant liabilities currently relate to future clean-up costs at former MGP facilities. These facilities were owned and operated by our predecessor companies from the mid-1800's to mid-1900's. By-products from the manufacture of gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose risks to human health and the environment. We currently have partial or full ownership responsibilities at former MGP sites that have a reserve balance of $38.8 million of the total $43.3 million as of December 31, 2014. Predominantly all of these MGP costs are recoverable from customers through our rates.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Although weak health risk associations reported in some epidemiology studies remain unexplained, most researchers, as well as numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies, have concluded that the available body of scientific information does not support the conclusion that EMF affects human health.

In accordance with recommendations of various regulatory bodies and public health organizations, we reduce EMF associated with new transmission lines by the use of designs that can be implemented without additional cost or at a modest cost. We do not believe that other capital expenditures are appropriate to minimize unsubstantiated risks.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government. The EPA initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" that endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector. The EPA has mandated greenhouse gas emission reporting beginning in 2011 for emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF_6 gas and methane.

We are continually evaluating the regulatory risks and regulatory uncertainty presented by climate change concerns. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. These could include federal "cap and trade" laws, carbon taxes, fuel and energy taxes, or regulations requiring additional capital expenditures at our generating facilities. We expect that any costs of these rules and regulations would be recovered from customers.

Connecticut, New Hampshire and Massachusetts are each members of the Regional Greenhouse Gas Initiative (RGGI), a cooperative effort by nine northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from coal- and oil-fired electric generating plants. Because CO_2 allowances issued by any participating state are usable across all nine RGGI state programs, the individual state CO_2 trading programs, in the aggregate, form one regional compliance market for CO_2 emissions. A regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three year compliance period that ended on December 31, 2014.

PSNH anticipates that its generating units will emit two million to three million tons of CO_2 per year, depending on the capacity factor and the utilization of the respective generation plant, excluding emissions from the operation of PSNH's Northern Wood Power Project, which emissions are an offset. New Hampshire legislation provided up to 1.5 million banked CO_2 allowances per year for PSNH's coal- and oil-fired electric generating plants during the 2012 through 2014 compliance period. PSNH satisfied its remaining RGGI requirements by purchasing CO_2 allowances at auction or in the secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers. Current legislation provides that the portion of the RGGI auction proceeds in excess of $1 per allowance will be refunded to customers.

Because none of NU's other subsidiaries, CL&P, NSTAR Electric or WMECO, currently owns any generating assets (other than WMECO's solar photovoltaic facilities that do not emit CO_2), none of them is required to acquire CO_2 allowances. However, the CO_2 allowance costs borne by the

generating facilities that are utilized by wholesale energy suppliers to satisfy energy supply requirements to CL&P, NSTAR Electric and WMECO will likely be included in the overall wholesale rates charged, which costs are then recoverable from customers.

FERC Hydroelectric Project Licensing

Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, (ii) the United States may take over the project, or (iii) the FERC may issue a new license to a new licensee, upon payment to the existing licensee of the lesser of the fair value or the net investment in the project, plus severance damages, less certain amounts earned by the licensee in excess of a reasonable rate of return.

PSNH owns nine hydroelectric generating stations with a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act and related FERC regulations, including provisions related to the condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment and severance damages and other matters. PSNH is currently in the early stages of relicensing its 6.5 MW Eastman Falls Hydro Station, the license for which expires in 2017.

EMPLOYEES

As of December 31, 2014, NU employed a total of 8,248 employees, excluding temporary employees, of which 1,548 were employed by CL&P, 1,717 were employed by NSTAR Electric 1,048 were employed by PSNH, and 310 were employed by WMECO. Approximately 51 percent of our employees are members of the International Brotherhood of Electrical Workers, the Utility Workers Union of America or The United Steelworkers, and are covered by 13 collective bargaining agreements.

INTERNET INFORMATION

Our website address is www.eversource.com. We make available through our website a link to the SEC's EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), at which site NU's, CL&P's, NSTAR Electric's, PSNH's and WMECO's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports may be reviewed. Information contained on the Company's website or that can be accessed through the website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Northeast Utilities, 107 Selden Street, Berlin, CT 06037.

Item 1A. Risk Factors

In addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" included immediately prior to Item 1, *Business*, above, we are subject to a variety of significant risks. Our susceptibility to certain risks, including those discussed in detail below, could exacerbate other risks. These risk factors should be considered carefully in evaluating our risk profile.

Cyber breaches, acts of war or terrorism, or grid disturbances could negatively impact our business.

Cyber breaches, acts of war or terrorism, physical attacks or grid disturbances resulting from internal or external sources could target our generation, transmission and distribution facilities or our information technology systems. Such actions could impair our ability to manage these facilities, operate our systems effectively, or properly manage our data, networks and programs, resulting in loss of service to customers.

Because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system.

Any such cyber breaches, acts of war or terrorism, physical attacks or grid disturbances could result in a significant decrease in revenues, significant expense to repair system damage or security breaches, and liability claims, which could have a material adverse impact on our financial position, results of operations or cash flows.

The unauthorized access to and the misappropriation of confidential and proprietary customer, employee, financial or system operating information could adversely affect our business operations and adversely impact our reputation.

In the regular course of business we maintain sensitive customer, employee, financial and system operating information and are required by various federal and state laws to safeguard this information. Cyber intrusions, security breaches, theft or loss of this information by cyber crime or otherwise could lead to the release of critical operating information or confidential customer or employee information, which could adversely affect our business operations or adversely impact our reputation, and could result in significant costs, fines and litigation. We maintain adequate privacy protection liability insurance to cover damages and defense costs arising from unauthorized disclosure of, or failure to protect, private information as well as costs for notification to, or for credit card monitoring of, customers, employees and other persons in the event of a breach of private information. This insurance covers amounts paid to avert, prevent or stop a network attack or the disclosure of personal information, and costs of a qualified forensics firm to determine the cause, source and extent of a network attack or to investigate, examine and analyze our network to find the cause, source and extent of a data breach. While we have implemented measures designed to prevent cyber-attacks and mitigate their effects should they occur, our systems are vulnerable to unauthorized access and cyber intrusions. We cannot determine the probability that a security breach may occur or quantify the potential impact of such an event.

The actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our Regulated companies charge their customers are determined by their state utility commissions and by FERC. These commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. FERC also regulates their transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters. The commissions' policies and regulatory actions could have a material impact on the Regulated companies' financial position, results of operations and cash flows.

Our transmission, distribution and generation systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows.

Our ability to properly operate our transmission, distribution and generation systems is critical to the financial performance of our business. Our transmission, distribution and generation businesses face several operational risks, including the breakdown or failure of or damage to equipment, including information technology equipment, or processes, especially due to age; labor disputes; disruptions in the delivery of electricity and natural gas, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; catastrophic events such as fires, explosions, or other similar occurrences; extreme weather conditions beyond equipment and plant design capacity; other unanticipated operations and maintenance expenses and liabilities; and potential claims for property damage or personal injuries beyond the scope of our insurance coverage. The failure of our transmission, distribution and generation systems to operate as planned may result in increased capital costs, reduced earnings or unplanned increases in operation and maintenance costs. As a result of our merger in 2012, we have implemented or expect to implement process and information technology system changes that are expected to provide significant improvements to our businesses. If these changes do not result in the improvements that we expect, regulators may determine that the costs for these improvements are not prudent and therefore not recoverable from customers, which may result in reduced earnings. At PSNH, outages at generating stations may be deemed imprudent by the NHPUC resulting in disallowance of replacement power and repair costs. Such costs that are not recoverable from our customers would have an adverse effect on our financial position, results of operations and cash flows.

We expect to invest in strategic development opportunities in both electric and natural gas transmission, but we may not be successful and projects may not commence operation as scheduled or be completed within budget, which could have a material adverse effect on our business prospects.

We are pursuing broader strategic development investment opportunities related to the construction of electric and natural gas transmission facilities, interconnections to generating resources and other investment opportunities. The development, construction and expansion of electric transmission and natural gas transmission facilities involve numerous risks. Various factors could result in increased costs or result in delays or cancellation of these projects. Risks include regulatory approval processes, new legislation, economic events or factors, environmental and community concerns, design and siting issues, difficulties in obtaining required rights of way, competition from incumbent utilities and other entities, and actions of strategic partners. Should any of these factors result in such delays or cancellations, our financial position, results of operations, and cash flows could be adversely affected or our future growth opportunities may not be realized as anticipated.

Economic events or factors, changes in regulatory or legislative policy and/or regulatory decisions or construction of new generation may delay completion of or displace or result in the abandonment of our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected earnings.

Our transmission construction plans could be adversely affected by economic events or factors, new legislation, regulations, or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions. Any of such events could cause delays in, or the inability to complete or abandonment of, economic or reliability related projects, which could adversely affect our ability to achieve forecasted earnings or to recover our investments or result in lower than expected rates of return. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all of such costs have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, our transmission projects may be delayed or displaced by new generation facilities, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

Many of our transmission projects are expected to help alleviate identified reliability issues and reduce customers' costs. However, if, due to economic events or factors or further regulatory or other delays, the in-service date for one or more of these projects is delayed, there may be increased risk of failures in the electricity transmission system and supply interruptions or blackouts, which could have an adverse effect on our earnings.

The FERC has followed a policy of providing incentives designed to encourage the construction of new transmission facilities, including higher returns on equity and allowing facilities under construction to be placed in rate base. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the levels presently anticipated.

Increases in electric and gas prices and/or a weak economy, can lead to changes in legislative and regulatory policy promoting increased energy efficiency, conservation, and self-generation and/or a reduction in our customers' ability to pay their bills, which may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and natural gas sales in our service territories. If any such declines were to occur without corresponding

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adjustments in rates at our Regulated companies that do not currently have revenue decoupling, then our revenues would be reduced and our future growth prospects would be limited.

In addition, a period of prolonged economic weakness could impact customers' ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses or other adverse effects on our financial position, results of operations or cash flows.

Changes in regulatory and/or legislative policy could negatively impact our transmission planning and cost allocation rules.

The existing FERC-approved New England transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with a FERC approved formula found in the transmission tariff. All New England transmission owners' agreement to this regional cost allocation is set forth in the Transmission Operating Agreement. This agreement can be modified with the approval of a majority of the transmission owning utilities and approval by FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the rates our distribution companies charge their retail customers.

FERC has issued rules requiring all regional transmission organizations and transmission owning utilities to make compliance changes to their tariffs and contracts in order to further encourage the construction of transmission for generation, including renewable generation. This compliance will require ISO-NE and New England transmission owners to develop methodologies that allow for regional planning and cost allocation for transmission projects chosen in the regional plan that are designed to meet public policy goals such as reducing greenhouse gas emissions or encouraging renewable generation. Such compliance may also allow non-incumbent utilities and other entities to participate in the planning and construction of new projects in our service area and regionally.

Changes in the Transmission Operating Agreement, the New England Transmission Tariff or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning, our earnings and our prospects for growth.

Changes in regulatory or legislative policy or unfavorable outcomes in regulatory proceedings could jeopardize our full and/or timely recovery of costs incurred by our regulated distribution and generation businesses.

Under state law, our Regulated companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Each of these companies prepares and submits periodic rate filings with their respective state regulatory commissions for review and approval. There is no assurance that these state commissions will approve the recovery of all such costs incurred by our Regulated companies, such as for construction, operation and maintenance, as well as a return on investment on their respective regulated assets. The amount of costs incurred by the Regulated companies, coupled with increases in fuel and energy prices, could lead to consumer or regulatory resistance to the timely recovery of such costs, thereby adversely affecting our financial position, results of operations or cash flows.

Additionally, state legislators may enact laws that significantly impact our Regulated companies' revenues, including by mandating electric or gas rate relief and/or by requiring surcharges to customer bills to support state programs not related to the utilities or energy policy. Such increases could pressure overall rates to our customers and our routine requests to regulators for rate relief.

In addition, CL&P, NSTAR Electric and WMECO procure energy for a substantial portion of their customers' needs via requests for proposal on an annual, semi-annual or quarterly basis. CL&P, NSTAR Electric and WMECO receive approval to recover the costs of these contracts from the PURA and DPU, respectively. While both regulatory agencies have consistently approved the solicitation processes, results and recovery of costs, management cannot predict the outcome of future solicitation efforts or the regulatory proceedings related thereto.

PSNH meets most of its energy requirements through its own generation resources and fixed-price forward purchase contracts. PSNH's remaining energy needs are met primarily through spot market purchases. Unplanned forced outages of its generating plants could increase the level of energy purchases needed by PSNH and therefore increase the market risk associated with procuring the energy to meet its requirements. PSNH recovers these costs through its ES rate, subject to a prudence review by the NHPUC. We cannot predict the outcome of future regulatory proceedings related to recovery of these costs.

Our goodwill is valued and recorded at an amount that, if impaired and written down, could adversely affect our future operating results and total capitalization.

We have a significant amount of goodwill on our consolidated balance sheet. The carrying value of goodwill represents the fair value of an acquired business in excess of identifiable assets and liabilities as of the acquisition date. As of December 31, 2014, goodwill totaled $3.5 billion, of which $3.2 billion was attributable to the acquisition of NSTAR in April 2012. Total goodwill represented approximately 35 percent of our $10 billion of shareholders' equity and approximately 12 percent of our total assets of $29.8 billion. We test our goodwill balances for impairment on an annual basis or whenever events occur or circumstances change that would indicate a potential for impairment. A determination that goodwill is deemed to be impaired would result in a non-cash charge that could materially adversely affect our results of operations and total capitalization. The annual goodwill impairment test in 2014 resulted in a conclusion that goodwill is not impaired.

Severe storms could cause significant damage to any of our facilities requiring extensive expenditures, the recovery for which is subject to approval by regulators.

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage, which may require us to incur additional costs that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial, particularly as customers

demand better and quicker response times to outages. If, upon review, any of our state regulatory authorities finds that our actions were imprudent, some of those restoration costs may not be recoverable from customers. The inability to recover a significant amount of such costs could have an adverse effect on our financial position, results of operations and cash flows.

NU and its utility subsidiaries are exposed to significant reputational risks, which make them vulnerable to increased regulatory oversight or other sanctions.

Because utility companies, including our electric and natural gas utility subsidiaries, have large consumer customer bases, they are subject to adverse publicity focused on the reliability of their distribution services and the speed with which they are able to respond to electric outages, natural gas leaks and similar interruptions caused by storm damage or other unanticipated events. Adverse publicity of this nature could harm the reputations of NU and its subsidiaries, and may make state legislatures, utility commissions and other regulatory authorities less likely to view NU and its subsidiaries in a favorable light, and may cause NU and its subsidiaries to be subject to less favorable legislative and regulatory outcomes or increased regulatory oversight. Unfavorable regulatory outcomes can include more stringent laws and regulations governing our operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material adverse effect on our business, results of operations, cash flow and financial condition of NU and each of its utility subsidiaries.

Limits on our access to and increases in the cost of capital may adversely impact our ability to execute our business plan.

We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. In addition, higher interest rates would increase our cost of borrowing, which could adversely impact our results of operations. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses.

Our counterparties may not meet their obligations to us or may elect to exercise their termination rights, which could adversely affect our earnings.

We are exposed to the risk that counterparties to various arrangements who owe us money, have contracted to supply us with energy, coal, or other commodities or services, or who work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations, will terminate such arrangements or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations or terminate such arrangements, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of, or cancel a capital project. Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected.

Judicial or regulatory proceedings or changes in regulatory or legislative policy could jeopardize full recovery of costs incurred by PSNH in constructing the Clean Air Project.

Pursuant to New Hampshire law, PSNH placed the Clean Air Project in service at its Merrimack Station. PSNH's recovery of costs in constructing the project is subject to prudence review by the NHPUC. A material prudence disallowance could adversely affect PSNH's financial position, results of operations or cash flows. While we believe we have prudently incurred all expenditures to date, we cannot predict the outcome of any prudence reviews. Our projected earnings and growth could be adversely affected were the NHPUC to deny recovery of some or all of PSNH's investment in the project.

The loss of key personnel or the inability to hire and retain qualified employees could have an adverse effect on our business, financial position and results of operations.

Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. We cannot guarantee that any member of our management or any key employee at the NU parent or subsidiary level will continue to serve in any capacity for any particular period of time. In addition, a significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. We have developed strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce, but cannot predict the impact of these plans on our ability to hire and retain key employees.

Market performance or changes in assumptions require us to make significant contributions to our pension and other postretirement benefit plans.

We provide a defined benefit pension plan and other postretirement benefits for a substantial number of employees, former employees and retirees. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors beyond our control. These factors include estimated investment returns, interest rates, discount rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In 2014, NU made contributions to the Pension Plans totaling $171.6 million. We expect to make contributions in 2015 totaling $155 million. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional large funding requirements, when combined with the financing requirements of our construction program, could impact the timing and amount of future equity and debt financings and negatively affect our financial position, results of operations or cash flows.

Costs of compliance with environmental regulations, including climate change legislation, may increase and have an adverse effect on our business and results of operations.

Our subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations that govern, among other things, air emissions, water discharges and the management of hazardous and solid waste. Compliance with these requirements requires us to incur significant costs relating to environmental monitoring, installation of pollution control equipment, emission fees, maintenance and upgrading of facilities, remediation and permitting. The costs of compliance with existing legal requirements or legal requirements not yet adopted may increase in the future. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and our financial position, results of operations or cash flows.

In addition, global climate change issues have received an increased focus from federal and state governments, including EPA's proposed draft carbon pollution emission guidelines for existing utility generating units, which could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the power plants we own and operate as well as general utility operations. Although we would expect that any costs of these rules and regulations would be recovered from customers, their impact on energy use by customers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time. The impact of these additional costs to customers could lead to a further reduction in energy consumption resulting in a decline in electricity and gas sales in our service territories, which would have an adverse impact on our business and financial position, results of operations or cash flows.

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control, or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. Revised or additional laws could result in significant additional expense and operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable in distribution company rates. The cost impact of any such laws, rules or regulations would be dependent upon the specific requirements adopted and cannot be determined at this time. For further information, see Item 1, *Business - Other Regulatory and Environmental Matters*, included in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent's liquidity is dependent on dividends from its subsidiaries, primarily the Regulated companies, its commercial paper program, and its ability to access the long-term debt and equity capital markets.

NU parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its debt service obligations and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or repay borrowings from NU parent, and/or NU parent's ability to access its commercial paper program or the long-term debt and equity capital markets. Prior to funding NU parent, the Regulated companies have financial obligations that must be satisfied, including among others, their operating expenses, debt service, preferred dividends (in the case of CL&P and NSTAR Electric), and obligations to trade creditors. Additionally, the Regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the Regulated companies not be able to pay dividends or repay funds due to NU parent, or if NU parent cannot access its commercial paper programs or the long-term debt and equity capital markets, NU parent's ability to pay interest, dividends and its own debt obligations would be restricted.

Item 1B. Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2. Properties

Transmission and Distribution System

As of December 31, 2014, NU and our electric operating subsidiaries owned the following:

NU	Electric Distribution	Electric Transmission
Number of substations owned	513	63
Transformer capacity (in kVa)	40,853,000	17,117,000
Overhead lines (distribution in pole miles and transmission in circuit miles)	48,496	3,880
Capacity range of overhead transmission lines (in kV)	N/A	69 to 345
Underground lines (distribution in conduit bank miles and transmission in cable miles)	16,770	408
Capacity range of underground transmission lines (in kV)	N/A	69 to 345

	CL&P		NSTAR Electric		PSNH		WMECO	
	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission	Distribution	Transmission
Number of substations owned	182	19	133	21	155	16	43	7
Transformer capacity (in kVa)	19,082,000	3,117,000	11,381,000	10,065,000	5,218,000	3,868,000	5,172,000	67,000
Overhead lines (distribution in pole miles and transmission in circuit miles)	18,376	1,630	14,338	742	11,987	1,027	3,795	481
Capacity range of overhead transmission lines (in kV)	N/A	69 to 345	N/A	115 to 345	N/A	115 to 345	N/A	69 to 345
Underground lines (distribution in conduit bank miles and transmission in cable miles)	1,186	137	13,496	260	1,795	1	293	10
Capacity range of underground transmission lines (in kV)	N/A	69 to 345	N/A	115 to 345	N/A	115	N/A	115

	NU	CL&P	NSTAR Electric	PSNH	WMECO
Underground and overhead line transformers in service	622,104	287,641	123,997	167,703	42,763
Aggregate capacity (in kVa)	35,196,926	15,118,641	10,828,218	7,122,928	2,127,139

Electric Generating Plants

As of December 31, 2014, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Steam Plants	5	1952-74	935,343
Hydro	20	1901-83	58,115
Internal Combustion	5	1968-70	101,869
Biomass	1	2006	42,594
Total PSNH Generating Plant	31		1,137,921

* Claimed capability represents winter ratings as of December 31, 2014. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2014, WMECO owned the following electric generating plants:

Type of Plant	Number of Sites	Year Installed	Claimed Capability** (kilowatts)
Solar Fixed Tilt, Photovoltaic	3	2010-14	8,000

** Claimed capability represents the direct current nameplate capacity of the plant.

CL&P and NSTAR Electric do not own any electric generating plants.

Natural Gas Distribution System

As of December 31, 2014, Yankee Gas owned 28 active gate stations, 201 district regulator stations, and approximately 3,300 miles of natural gas main pipeline. Yankee Gas also owns a liquefaction and vaporization plant and above ground storage tank with a storage capacity equivalent of 1.2 Bcf of natural gas in Waterbury, Connecticut.

As of December 31, 2014, NSTAR Gas owned 20 active gate stations, 162 district regulator stations, and approximately 3,230 miles of natural gas main pipeline. Hopkinton, another subsidiary of NU, owns a satellite vaporization plant and above ground storage tanks in Acushnet, MA. In

addition, Hopkinton owns a liquefaction and vaporization plant with above ground storage tanks in Hopkinton, MA. Combined, the two plants' tanks have an aggregate storage capacity equivalent to 3.5 Bcf of natural gas that is provided to NSTAR Gas under contract.

Franchises

CL&P Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to provide electric transmission and distribution services in the respective areas in which it is now supplying such service.

In addition to the right to provide electric transmission and distribution services as set forth above, the franchises of CL&P include, among others, limited rights and powers, as set forth under Connecticut law and the special acts of the General Assembly constituting its charter, to manufacture, generate, purchase and/or sell electricity at retail, including to provide Standard Service, Supplier of Last Resort service and backup service, to sell electricity at wholesale and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain. Connecticut law prohibits an electric distribution company from owning or operating generation assets. However, under "An Act Concerning Energy Independence," enacted in 2005, CL&P is permitted to own up to 200 MW of peaking facilities if the PURA determines that such facilities will be more cost effective than other options for mitigating FMCC and Locational Installed Capacity (LICAP) costs. In addition, under "An Act Concerning Electricity and Energy Efficiency," enacted in 2007, an electric distribution company, such as CL&P, is permitted to purchase an existing electric generating plant located in Connecticut that is offered for sale, subject to prior approval from the PURA and a determination by the PURA that such purchase is in the public interest. Finally, Connecticut law also allows CL&P to submit a proposal to the DEEP to build, own or operate one or more generation facilities up to 10 MWs using Class I renewable energy.

NSTAR Electric and NSTAR Gas Through their charters, which are unlimited in time, NSTAR Electric and NSTAR Gas have the right to engage in the business of delivering and selling electricity and natural gas within their respective service territories, and have powers incidental thereto and are entitled to all the rights and privileges of and subject to the duties imposed upon electric and natural gas companies under Massachusetts laws. The locations in public ways for electric transmission and distribution lines and natural gas distribution pipelines are obtained from municipal and other state authorities who, in granting these locations, act as agents for the state. In some cases the actions of these authorities are subject to appeal to the DPU. The rights to these locations are not limited in time and are subject to the action of these authorities and the legislature. Under Massachusetts law, with the exception of municipal-owned utilities, no other entity may provide electric or natural gas delivery service to retail customers within NSTAR's service territory without the written consent of NSTAR Electric and/or NSTAR Gas. This consent must be filed with the DPU and the municipality so affected.

The Massachusetts restructuring legislation defines service territories as those territories actually served on July 1, 1997 and following municipal boundaries to the extent possible. The restructuring legislation further provides that until terminated by law or otherwise, distribution companies shall have the exclusive obligation to serve all retail customers within their service territories and no other person shall provide distribution service within such service territories without the written consent of such distribution companies. Pursuant to the Massachusetts restructuring legislation, the DPU (then, the Department of Telecommunications and Energy) was required to define service territories for each distribution company, including NSTAR Electric. The DPU subsequently determined that there were advantages to the exclusivity of service territories and issued a report to the Massachusetts Legislature recommending against, in this regard, any changes to the restructuring legislation.

PSNH The NHPUC, pursuant to statutory requirements, has issued orders granting PSNH exclusive franchises to distribute electricity in the respective areas in which it is now supplying such service.

In addition to the right to distribute electricity as set forth above, the franchises of PSNH include, among others, rights and powers to manufacture, generate, purchase, and transmit electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. PSNH's status as a public utility gives it the ability to petition the NHPUC for the right to exercise eminent domain for its transmission and distribution services in appropriate circumstances.

PSNH is also subject to certain regulatory oversight by the Maine Public Utilities Commission and the Vermont Public Service Board.

WMECO WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and for extensions of lines in public highways. Further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority and pursuant to state laws, has the power of eminent domain.

The Massachusetts restructuring legislation applicable to NSTAR Electric (described above) is also applicable to WMECO.

Yankee Gas Yankee Gas holds valid franchises to sell natural gas in the areas in which Yankee Gas supplies natural gas service, which it acquired either directly or from its predecessors in interest. Generally, Yankee Gas holds franchises to serve customers in areas designated by those franchises as well as in most other areas throughout Connecticut so long as those areas are not occupied and served by another natural gas utility under a valid franchise of its own or are not subject to an exclusive franchise of another natural gas utility. Yankee Gas' franchises are perpetual but remain subject to the power of alteration, amendment or repeal by the General Assembly of the State of Connecticut, the power of revocation by the PURA and certain approvals, permits and consents of public authorities and others prescribed by statute. Generally, Yankee Gas' franchises include, among other rights and powers, the right and power to manufacture, generate, purchase, transmit and distribute natural gas and to erect and maintain certain

facilities on public highways and grounds, and the right of eminent domain, all subject to such consents and approvals of public authorities and others as may be required by law.

Item 3. Legal Proceedings

1. Yankee Companies v. U.S. Department of Energy

DOE Phase I Damages - In 1998, the Yankee Companies (CYAPC, YAEC and MYAPC) filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE (DOE Phase I Damages). Phase I covered damages for the period 1998 through 2002. Following multiple appeals and cross-appeals in December 2012, the judgment awarding CYAPC $39.6 million, YAEC $38.3 million and MYAPC $81.7 million became final.

In January 2013, the proceeds from the DOE Phase I Damages Claim were received by the Yankee Companies and transferred to each Yankee Company's respective decommissioning trust.

In June 2013, FERC approved CYAPC, YAEC and MYAPC to reduce rates in their wholesale power contracts through the application of the DOE proceeds for the benefit of customers. Changes to the terms of the wholesale power contracts became effective on July 1, 2013. In accordance with the FERC order, CL&P, NSTAR Electric, PSNH and WMECO began receiving the benefit of the DOE proceeds, and the benefits have been passed on to customers.

On September 17, 2014, in accordance with the MYAPC refund plan, MYAPC returned a portion of the DOE Phase I Damages proceeds to the member companies, including CL&P, NSTAR Electric, PSNH, and WMECO, in the amount of $3.2 million, $1.1 million, $1.4 million and $0.8 million, respectively.

DOE Phase II Damages - In December 2007, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred related to the alleged failure of the DOE to provide for a permanent facility to store spent nuclear fuel generated in years 2001 through 2008 for CYAPC and YAEC and from 2002 through 2008 for MYAPC (DOE Phase II Damages). In November 2013, the court issued a final judgment awarding CYAPC $126.3 million, YAEC $73.3 million, and MYAPC $35.8 million. On January 14, 2014, the Yankee Companies received a letter from the U.S. Department of Justice stating that the DOE will not appeal the court's final judgment.

In March and April 2014, CYAPC, YAEC and MYAPC received payment of $126.3 million, $73.3 million and $35.8 million, respectively, of the DOE Phase II Damages proceeds and made the required informational filing with FERC in accordance with the process and methodology outlined in the 2013 FERC order. The Yankee Companies returned the DOE Phase II Damages proceeds to the member companies, including CL&P, NSTAR Electric, PSNH, and WMECO, for the benefit of their respective customers, on June 1, 2014. Refunds to CL&P's, NSTAR Electric's, PSNH's and WMECO's customers for these DOE proceeds began in the third quarter of 2014.

DOE Phase III Damages - In August 2013, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years 2009 through 2012. The presiding judge issued a Pre-Trial Scheduling Order on September 3, 2014 that set the case for trial from June 30 to July 2, 2015. The Order also established January 5, 2015 for the close of fact discovery and March 30, 2015 as the close of expert discovery. Expert discovery is ongoing.

2. Conservation Law Foundation v. PSNH

On July 21, 2011, the Conservation Law Foundation (CLF) filed a citizens suit under the provisions of the federal Clean Air Act against PSNH alleging permitting violations at the company's Merrimack generating station. The suit alleges that PSNH failed to have proper permits for replacement of the Unit 2 turbine at Merrimack, installation of activated carbon injection equipment for the unit, and violated a permit condition concerning operation of the electrostatic precipitators at the station. On September 27, 2012, the federal court dismissed portions of CLF's suit pertaining to the installation of activated carbon injection and the electrostatic precipitators. CLF filed an amended complaint on May 28, 2013, related to routine maintenance of the boiler performed in 2008 and 2009. The suit seeks injunctive relief, civil penalties, and costs. CLF has pursued similar claims before the NHPUC, the N.H. Air Resources Council, and the N.H. Site Evaluation Committee, all of which have been denied. PSNH believes this suit is without merit and intends to defend it vigorously. The deadline for summary judgment is November 2015. Trial is scheduled for the spring of 2016.

3. Other Legal Proceedings

For further discussion of legal proceedings, see Item 1, *Business:* "- Electric Distribution Segment," "- Electric Transmission Segment," and "- Natural Gas Distribution Segment" for information about various state regulatory and rate proceedings, civil lawsuits related thereto, and information about proceedings relating to power, transmission and pricing issues; "- Nuclear Fuel Storage" for information related to high-level nuclear waste; and "- Other Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality requirements, toxic substances and hazardous waste, electric and magnetic fields, licensing of hydroelectric projects, and other matters. In addition, see Item 1A, *Risk Factors*, for general information about several significant risks.

Item 4. Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the executive officers of NU as of February 18, 2015. All of the Company's officers serve terms of one year and until their successors are elected and qualified:

Name	Age	Title
Jay S. Buth	45	Vice President, Controller and Chief Accounting Officer.
Gregory B. Butler	57	Senior Vice President and General Counsel.
Christine M. Carmody*	52	Senior Vice President-Human Resources of NUSCO.
James J. Judge	59	Executive Vice President and Chief Financial Officer.
Thomas J. May	67	Chairman of the Board, President and Chief Executive Officer.
David R. McHale	54	Executive Vice President and Chief Administrative Officer.
Joseph R. Nolan, Jr.*	51	Senior Vice President-Corporate Relations of NUSCO.
Leon J. Olivier	66	Executive Vice President-Enterprise Energy Strategy and Business Development.
Werner J. Schweiger	55	Executive Vice President and Chief Operating Officer.

* Deemed an executive officer of NU pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.

Jay S. Buth. Mr. Buth has served as Vice President, Controller and Chief Accounting Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. Previously, Mr. Buth served as Vice President-Accounting and Controller of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from June 2009 until April 10, 2012. From June 2006 through January 2009, Mr. Buth served as the Vice President and Controller for New Jersey Resources Corporation, an energy services holding company that provides natural gas and wholesale energy services, including transportation, distribution and asset management.

Gregory B. Butler. Mr. Butler has served as Senior Vice President and General Counsel of NU since May 1, 2014, of NSTAR Electric, and NSTAR Gas since April 10, 2012, and of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since March 9, 2006. Mr. Butler has served as a Director of NSTAR Electric and NSTAR Gas since April 10, 2012, of NUSCO since November 27, 2012, and of CL&P, PSNH, WMECO and Yankee Gas since April 22, 2009. Mr. Butler previously served as Senior Vice President, General Counsel and Secretary of NU from April 10, 2012 until May 1, 2014, and as Senior Vice President and General Counsel of NU from December 1, 2005 to April 10, 2012. He has served as a Director of Eversource Energy Foundation, Inc. since December 1, 2002.

Christine M. Carmody. Ms. Carmody has served as Senior Vice President-Human Resources of NUSCO since April 10, 2012 and as a Director of NUSCO since November 27, 2012. Ms. Carmody previously served as Senior Vice President-Human Resources of CL&P, PSNH, WMECO and Yankee Gas from November 27, 2012 to September 29, 2014, and of NSTAR Electric and NSTAR Gas from August 1, 2008 to September 29, 2014, and as a Director of CL&P, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014. Previously, Ms. Carmody served as Vice President-Organizational Effectiveness of NSTAR, NSTAR Electric and NSTAR Gas from June 2006 to August 2008. Ms. Carmody has served as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. She has served as a Trustee of the NSTAR Foundation since August 1, 2008.

James J. Judge. Mr. Judge has served as Executive Vice President and Chief Financial Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO and as a Director of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012 and of NSTAR Electric and NSTAR Gas since September 27, 1999. Previously, Mr. Judge served as Senior Vice President and Chief Financial Officer of NSTAR, NSTAR Electric and NSTAR Gas from 1999 until April 2012. Mr. Judge has served as Treasurer and as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. He has served as a Trustee of the NSTAR Foundation since December 12, 1995.

Thomas J. May. Mr. May has served as Chairman of the Board of NU since October 10, 2013, and as President and Chief Executive Officer and as a Trustee of NU; as Chairman and a Director of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas; and as Chairman, President and Chief Executive Officer and a Director of NUSCO since April 10, 2012. Mr. May has served as a Director of NSTAR Electric and NSTAR Gas since September 27, 1999. Mr. May previously served as Chairman, President and Chief Executive Officer and a Trustee of NSTAR, and as Chairman, President and Chief Executive Officer of NSTAR Electric and NSTAR Gas until April 10, 2012. He served as Chairman, Chief Executive Officer and a Trustee since NSTAR was formed in 1999, and was elected President in 2002. Mr. May has served as Chairman of the Board of Eversource Energy Foundation, Inc. since October 15, 2013, and as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. He previously served as President of Eversource Energy Foundation, Inc. from October 15, 2013 to September 29, 2014. He has served as a Trustee of the NSTAR Foundation since August 18, 1987.

David R. McHale. Mr. McHale has served as Executive Vice President and Chief Administrative Officer of NU and NUSCO since April 10, 2012 and as a Director of NUSCO since January 1, 2005. Mr. McHale previously served as Executive Vice President and Chief Administrative Officer of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and as a Director of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014, of PSNH, WMECO and Yankee Gas from January 1, 2005 to September 29, 2014, and of CL&P from January 15, 2007 to September 29, 2014. Previously, Mr. McHale served as Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2009 to April 2012, and as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2005 to December 2008. He has served as a Director of Eversource Energy Foundation, Inc. since January 1, 2005. Mr. McHale has served as a Trustee of the NSTAR Foundation since April 10, 2012.

Item 4. Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

Joseph R. Nolan, Jr. Mr. Nolan has served as Senior Vice President-Corporate Relations of NUSCO since April 10, 2012 and as a Director of NUSCO since November 27, 2012. Mr. Nolan previously served as Senior Vice President-Corporate Relations of NSTAR Electric and NSTAR Gas from April 10, 2012 to September 29, 2014, and of CL&P, PSNH, WMECO and Yankee Gas from November 27, 2012 to September 29, 2014, as a Director of CL&P, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014. Previously, Mr. Nolan served as Senior Vice President-Customer & Corporate Relations of NSTAR, NSTAR Electric and NSTAR Gas from 2006 until April 10, 2012. Mr. Nolan has served as a Director of Eversource Energy Foundation, Inc. since April 10, 2012, and has served as Executive Director of Eversource Energy Foundation, Inc. since October 15, 2013. He has served as a Trustee of the NSTAR Foundation since October 1, 2000.

Leon J. Olivier. Mr. Olivier has served as Executive Vice President-Enterprise Energy Strategy and Business Development of NU since September 2, 2014 and as a Director of NUSCO since January 17, 2005. Mr. Olivier previously served as Executive Vice President and Chief Operating Officer of NU and NUSCO from May 13, 2008 until September 2, 2014, and as Chief Executive Officer of NSTAR Electric and NSTAR Gas from April 10, 2012 until August 11, 2014, of CL&P, PSNH, WMECO and Yankee Gas from January 15, 2007 to September 29, 2014, and of CL&P from September 10, 2001 to September 29, 2014, and as a Director of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014, of PSNH, WMECO and Yankee Gas from January 17, 2005 to September 29, 2014, and of CL&P from September 10, 2001 to September 29, 2014. Previously, Mr. Olivier served as Executive Vice President-Operations of NU from February 13, 2007 to May 12, 2008. He has served as a Director of Eversource Energy Foundation, Inc. since April 1, 2006. Mr. Olivier has served as a Trustee of the NSTAR Foundation since April 10, 2012.

Werner J. Schweiger. Mr. Schweiger has served as Executive Vice President and Chief Operating Officer of NU since September 2, 2014 and of NUSCO since August 11, 2014, and as Chief Executive Officer of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas since August 11, 2014, and as a Director of NUSCO, NSTAR Gas and Yankee Gas since September 29, 2014 and of CL&P, PSNH, NSTAR Electric and WMECO since May 28, 2013. He previously served as President-Electric Distribution of NUSCO from January 16, 2013 until August 11, 2014 and as President of NSTAR Electric from April 10, 2012 until January 16, 2013 and as a Director of NSTAR Electric from November 27, 2012 to January 16, 2013. From February 27, 2002 until April 10, 2012, Mr. Schweiger was Senior Vice President-Operations of NSTAR Electric and NSTAR Gas. Mr. Schweiger has served as a Director of Eversource Energy Foundation, Inc. since September 29, 2014. He has served as a Trustee of the NSTAR Foundation since April 25, 2002.

PART II

Item 5. Market for the Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

(a) Market Information and (c) Dividends

NU. Our common shares are listed on the New York Stock Exchange. Effective February 19, 2015, the ticker symbol is "ES." The high and low sales prices of our common shares and the dividends declared, for the past two years, by quarter, are shown below.

Year	Quarter	High	Low	Dividends Declared
2014	First	$ 45.69	$ 41.28	$ 0.393
	Second	47.60	44.28	0.393
	Third	47.37	41.92	0.393
	Fourth	56.66	44.37	0.393
2013	First	$ 43.49	$ 38.60	$ 0.368
	Second	45.66	39.35	0.368
	Third	45.13	40.01	0.368
	Fourth	43.75	40.60	0.368

Information with respect to dividend restrictions for us, CL&P, NSTAR Electric, PSNH, and WMECO is contained in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, under the caption "Liquidity" and Item 8, *Financial Statements and Supplementary Data*, in the *Combined Notes to Consolidated Financial Statements*, within this Annual Report on Form 10-K.

There is no established public trading market for the common stock of CL&P, NSTAR Electric, PSNH and WMECO. All of the common stock of CL&P, NSTAR Electric, PSNH and WMECO is held solely by NU.

Common stock dividends approved and paid to NU during the year were as follows:

	For the Years Ended December 31,	
(Millions of Dollars)	2014	2013
CL&P	$ 171.2	$ 152.0
NSTAR Electric	253.0	56.0
PSNH	66.0	68.0
WMECO	60.0	40.0

(b) Holders

As of January 31, 2015, there were 44,860 registered common shareholders of our company on record. As of the same date, there were a total of 317,203,765 common shares issued.

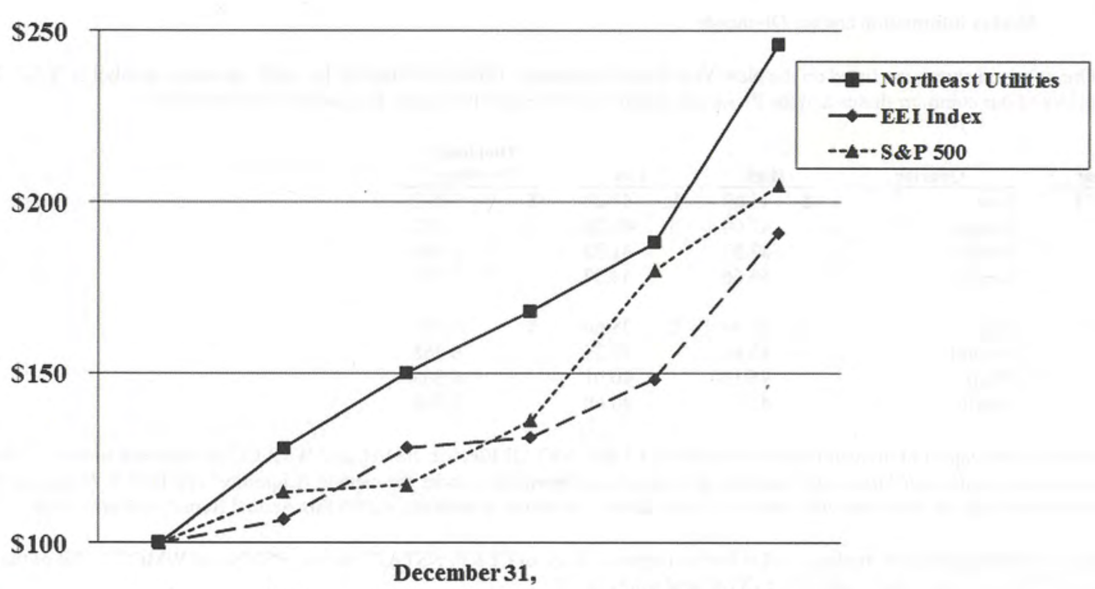
(d) Securities Authorized for Issuance Under Equity Compensation Plans

For information regarding securities authorized for issuance under equity compensation plans, see Item 12, *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*, included in this Annual Report on Form 10-K.

(e) Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in 2009 in Northeast Utilities common stock, as compared with the S&P 500 Stock Index and the EEI Index for the period 2010 through 2014, assuming all dividends are reinvested.

Total Shareholder Return



	2009	2010	2011	2012	2013	2014
Northeast Utilities	$100	$128	$150	$168	$188	$246
EEI Index	$100	$107	$128	$131	$148	$191
S&P 500	$100	$115	$117	$136	$180	$205

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table discloses purchases of our common shares made by us or on our behalf for the periods shown below. The common shares purchased consist of open market purchases made by the Company or an independent agent. These share transactions related to the Company's Long-Term Incentive Plans.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans and Programs (at month end)
October 1 - October 31, 2014	-	$ -	-	-
November 1 - November 30, 2014	-	-	-	-
December 1 - December 31, 2014	62,976	50.91	-	-
Total	62,976	$ 50.91	-	-

Item 6. Selected Consolidated Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and common share information)	2014	2013	2012 [(a)]	2011	2010
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 18,647,041	$ 17,576,186	$ 16,605,010	$ 10,403,065	$ 9,567,726
Total Assets	29,777,975	27,795,537	28,302,824	15,647,066	14,472,601
Total Capitalization (b) (c)	18,983,983	18,077,274	17,356,112	9,078,321	8,627,985
Obligations Under Capital Leases (b)	9,434	10,744	11,071	12,358	12,236
Income Statement Data:					
Operating Revenues	$ 7,741,856	$ 7,301,204	$ 6,273,787	$ 4,465,657	$ 4,898,167
Net Income	827,065	793,689	533,077	400,513	394,107
Net Income Attributable to Noncontrolling Interests	7,519	7,682	7,132	5,820	6,158
Net Income Attributable to Controlling Interest	$ 819,546	$ 786,007	$ 525,945	$ 394,693	$ 387,949
Common Share Data:					
Net Income Attributable to Controlling Interest:					
Basic Earnings Per Common Share	$ 2.59	$ 2.49	$ 1.90	$ 2.22	$ 2.20
Diluted Earnings Per Common Share	$ 2.58	$ 2.49	$ 1.89	$ 2.22	$ 2.19
Weighted Average Common Shares Outstanding:					
Basic	316,136,748	315,311,387	277,209,819	177,410,167	176,636,086
Diluted	317,417,414	316,211,160	277,993,631	177,804,568	176,885,387
Dividends Declared Per Common Share	$ 1.57	$ 1.47	$ 1.32	$ 1.10	$ 1.03
Market Price - Closing (high) (d)	$ 56.15	$ 45.33	$ 40.57	$ 36.31	$ 32.05
Market Price - Closing (low) (d)	$ 41.52	$ 38.67	$ 33.53	$ 30.46	$ 24.78
Market Price - Closing (end of year) (d)	$ 53.52	$ 42.39	$ 39.08	$ 36.07	$ 31.88
Book Value Per Common Share (end of year)	$ 31.47	$ 30.49	$ 29.41	$ 22.65	$ 21.60
Tangible Book Value Per Common Share (end of year) (e)	$ 20.37	$ 19.32	$ 18.21	$ 21.03	$ 19.97
Rate of Return Earned on Average Common Equity (%) (f)	8.4	8.3	7.9	10.1	10.7
Market-to-Book Ratio (end of year) (g)	1.7	1.4	1.3	1.6	1.5
Capitalization:					
Total Equity	53 %	53 %	53 %	44 %	44 %
Preferred Stock, not subject to mandatory redemption	1	1	1	1	1
Long-Term Debt (b) (c)	46	46	46	55	55
	100 %	100 %	100 %	100 %	100 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.
(b) Includes portions due within one year.
(c) Excludes RRBs.
(d) Market price information reflects closing prices as reflected by the New York Stock Exchange.
(e) Common Shareholders' Equity adjusted for goodwill and intangibles divided by total common shares outstanding.
(f) Net Income Attributable to Controlling Interest divided by average Common Shareholders' Equity.
(g) The closing market price divided by the book value per share.

CL&P Selected Financial Data (Unaudited)

(Thousands of Dollars)	2014	2013	2012	2011	2010
Operating Revenues	$ 2,692,582	$ 2,442,341	$ 2,407,449	$ 2,548,387	$ 2,999,102
Net Income	287,754	279,412	209,725	250,164	244,143
Cash Dividends on Common Stock	171,200	151,999	100,486	243,218	217,691
Property, Plant and Equipment, Net	6,809,664	6,451,259	6,152,959	5,827,384	5,586,504
Total Assets	9,360,108	8,980,502	9,142,088	8,791,396	8,255,192
Long-Term Debt (a)	2,841,951	2,741,208	2,862,790	2,583,753	2,583,102
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	8,439	9,309	9,960	10,715	10,613

(a) Includes portions due within one year.

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of any accounting changes materially affecting the comparability of the information reflected in the tables above.

NU Selected Consolidated Sales Statistics

	2014	2013	2012 (a)	2011	2010
Revenues: *(Thousands)*					
Residential	$ 3,288,313	$ 3,073,181	$ 2,731,951	$ 2,091,270	$ 2,336,078
Commercial	2,471,440	2,387,535	1,604,661	1,236,374	1,346,228
Industrial	348,698	339,917	753,974	252,878	268,598
Wholesale	447,899	486,515	357,223	350,413	506,475
Other and Eliminations	97,090	56,547	130,137	47,485	(29,878)
Total Electric	6,653,440	6,343,695	5,577,946	3,978,420	4,427,501
Natural Gas	1,002,880	855,601	572,857	430,799	434,277
Total - Regulated Companies	7,656,320	7,199,296	6,150,803	4,409,219	4,861,778
Other and Eliminations	85,536	101,908	122,984	56,438	36,389
Total	$ 7,741,856	$ 7,301,204	$ 6,273,787	$ 4,465,657	$ 4,898,167
Regulated Companies - Sales: *(GWh)*					
Residential	21,317	21,896	19,719	14,766	14,913
Commercial	27,449	27,787	24,537	14,628	14,836
Industrial	5,676	5,648	5,462	4,418	4,481
Wholesale	3,018	855	2,154	1,020	3,423
Total	57,460	56,186	51,872	34,832	37,653
Regulated Companies - Customers: *(Average)*					
Residential	2,734,047	2,718,727	2,711,407	1,710,342	1,704,197
Commercial	373,511	371,897	370,389	199,240	198,558
Industrial	8,016	8,109	8,279	7,083	7,150
Total Electric	3,115,574	3,098,733	3,090,075	1,916,665	1,909,905
Natural Gas	499,186	493,563	483,770	207,753	205,885
Total	3,614,760	3,592,296	3,573,845	2,124,418	2,115,790

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.

CL&P Selected Sales Statistics

	2014	2013	2012	2011	2010
Revenues: *(Thousands)*					
Residential	$ 1,474,181	$ 1,294,160	$ 1,263,845	$ 1,345,290	$ 1,597,754
Commercial	879,343	780,585	732,620	758,145	853,956
Industrial	149,220	129,557	126,165	126,783	144,463
Wholesale	146,787	219,367	214,807	278,751	441,660
Other	43,051	18,672	70,012	39,418	(38,731)
Total	$ 2,692,582	$ 2,442,341	$ 2,407,449	$ 2,548,387	$ 2,999,102
Sales: *(GWh)*					
Residential	10,026	10,314	9,978	10,092	10,196
Commercial	9,643	9,770	9,705	9,809	10,002
Industrial	2,377	2,320	2,426	2,414	2,467
Wholesale	736	851	1,155	1,592	3,040
Total	22,782	23,255	23,264	23,907	25,705
Customers: *(Average)*					
Residential	1,111,467	1,105,417	1,103,397	1,100,740	1,096,576
Commercial	109,093	108,735	108,589	108,235	107,532
Industrial	3,213	3,247	3,301	3,331	3,359
Total	1,223,773	1,217,399	1,215,287	1,212,306	1,207,467

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

NORTHEAST UTILITIES AND SUBSIDIARIES

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related combined notes included in this Annual Report on Form 10-K. References in this Annual Report on Form 10-K to "NU," the "Company," "we," "us," and "our" refer to Northeast Utilities and subsidiaries. Our merger was effective April 10, 2012, and all subsequent results of operations and cash flows include NSTAR and its subsidiaries throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*. On February 2, 2015, NU, CL&P, NSTAR Electric, PSNH and WMECO commenced doing business as Eversource Energy.

All per share amounts are reported on a diluted basis. The consolidated financial statements of NU, NSTAR Electric and PSNH and the financial statements of CL&P and WMECO are herein collectively referred to as the "financial statements." Refer to the Glossary of Terms included in this combined Annual Report on Form 10-K for abbreviations and acronyms used throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

The only common equity securities that are publicly traded are common shares of NU. The earnings and EPS of each business discussed below do not represent a direct legal interest in the assets and liabilities of such business but rather represent a direct interest in our assets and liabilities as a whole. EPS by business is a financial measure not recognized under GAAP that is calculated by dividing the Net Income Attributable to Controlling Interest of each business by the weighted average diluted NU common shares outstanding for the year. The discussion below also includes non-GAAP financial measures referencing our 2014, 2013 and 2012 earnings and EPS excluding certain integration and merger costs related to NU's merger with NSTAR. We use these non-GAAP financial measures to evaluate and to provide details of earnings by business and to more fully compare and explain our 2014, 2013 and 2012 results without including the impact of these items. Due to the nature and significance of these items on Net Income Attributable to Controlling Interest, we believe that the non-GAAP presentation is more representative of our financial performance and provides additional and useful information to readers of this report in analyzing historical and future performance by business. These non-GAAP financial measures should not be considered as an alternative to reported Net Income Attributable to Controlling Interest or EPS determined in accordance with GAAP as an indicator of operating performance.

Reconciliations of the above non-GAAP financial measures to the most directly comparable GAAP measures of consolidated diluted EPS and Net Income Attributable to Controlling Interest are included under "Financial Condition and Business Analysis – Overview – Consolidated" and "Financial Condition and Business Analysis – Overview – Regulated Companies" in *Management's Discussion and Analysis of Financial Condition and Results of Operations*, herein.

Financial Condition and Business Analysis

Executive Summary

The following items in this executive summary are explained in more detail in this *Management's Discussion and Analysis of Financial Condition and Results of Operations*:

Results:

- We earned $819.5 million, or $2.58 per share, in 2014, compared with $786 million, or $2.49 per share, in 2013. Excluding integration costs, we earned $841.6 million, or $2.65 per share, in 2014 and $799.8 million, or $2.53 per share, in 2013.

- Our electric distribution segment, which includes generation, earned $462.4 million, or $1.45 per share, in 2014, compared with $427 million, or $1.35 per share, in 2013. Our transmission segment earned $295.4 million, or $0.93 per share, in 2014, compared with $287 million, or $0.91 per share, in 2013. Our natural gas distribution segment earned $72.3 million, or $0.23 per share, in 2014, compared with $60.9 million, or $0.19 per share, in 2013.

- NU parent and other companies had a net loss of $10.6 million, or $0.03 per share, in 2014, compared with earnings of $11.1 million, or $0.04 per share, in 2013. The 2014 and 2013 results reflect $22.1 million, or $0.07 per share, and $13.8 million, or $0.04 per share, respectively, of integration costs.

Legislative, Regulatory, Policy and Other Items:

- Pursuant to the FERC orders issued and other developments in the pending base ROE complaint proceedings further described in the "FERC Regulatory Issues – FERC Base ROE Complaints" section of this *Management's Discussion and Analysis of Financial Condition and Results of Operations,* the Company recorded reserves at its electric subsidiaries to recognize the potential financial impact of these rulings and developments in both 2014 and 2013. The net aggregate after-tax charge to earnings totaled $22.4 million and $14.3 million in 2014 and 2013, respectively.

- On September 16, 2014, NU and Spectra Energy Corp announced Access Northeast, a natural gas pipeline expansion project. Access Northeast will enhance the Algonquin and Maritimes pipeline systems using existing routes. NU and Spectra Energy Corp will have equal ownership interest in the project. On February 18, 2015, NU, Spectra Energy Corp and National Grid announced the addition of National Grid as a co-developer in the project for a total ownership interest of 20 percent, with NU and Spectra Energy Corp each owning 40 percent. The total project cost, subject to FERC approval, is expected to be approximately $3 billion and has an anticipated in-service date of November 2018.

- In September 2014, pursuant to legislation enacted in 2014, the NHPUC opened a docket that required them to commence and expedite a proceeding to determine whether all or some of PSNH's generation assets should be divested. An NHPUC progress report must be completed by March 31, 2015. In October 2014, the NHPUC concluded its hearings in the Clean Air Project prudence review to determine the prudent costs of PSNH's compliance with the law requiring scrubber installation. On December 26, 2014, PSNH requested that the NHPUC stay this proceeding in order to allow discussions to take place with other significant parties to determine whether a collaborative resolution of all issues was achievable. On January 15, 2015, the NHPUC issued an order granting the motion to stay in this proceeding, and settlement discussions have ensued.

- On December 17, 2014, PURA issued a final decision in CL&P's rate case, effective December 1, 2014, for a total distribution rate increase of $134 million. The distribution rate increase included a revenue decoupling reconciliation mechanism, system resiliency costs, and, pursuant to a March 12, 2014 PURA order approving such costs, the recovery of 2011 and 2012 storm restoration costs over a six-year period. In addition, CL&P began recovering the 2013 storm costs and residual 2012 Storm Sandy costs over a seven-year period beginning December 1, 2014. Including the $65.4 million of DOE Phase II Damages proceeds CL&P was allowed to credit to its deferred storm costs, CL&P has now been approved to recover all of its previously deferred storm costs in distribution rates.

- On December 31, 2014, NSTAR Electric, NSTAR Gas and the Massachusetts Attorney General filed a comprehensive settlement agreement with the DPU. The comprehensive settlement agreement included resolution of the outstanding NSTAR Electric CPSL program filings, the NSTAR Electric and NSTAR Gas PAM and energy efficiency-related customer billing adjustments reported in 2012, and the NSTAR Electric energy efficiency program filings regarding LBR. If approved by the DPU, NSTAR Electric and NSTAR Gas will be required to refund a total of $44.7 million to their respective customers, which was included in our regulatory liabilities as of December 31, 2014. Upon the DPU's approval, we will adjust our regulatory liabilities, which we expect will result in an after-tax benefit of approximately $14 million. We expect a response from the DPU in the first quarter of 2015.

Liquidity:

- Cash and cash equivalents totaled $38.7 million as of December 31, 2014, compared with $43.4 million as of December 31, 2013.

- Investments in property, plant and equipment totaled $1.6 billion in 2014 and $1.5 billion in 2013.

- Cash flows provided by operating activities totaled $1.64 billion in 2014, compared with $1.66 billion in 2013. As compared to 2013, the 2014 operating cash flows were favorably impacted by approximately $132 million in DOE Damages proceeds resulting from the spent nuclear fuel litigation received by CL&P, NSTAR Electric, PSNH and WMECO from the Yankee Companies, the absence of 2013 cash disbursements for major storm restoration costs, the decrease of approximately $130 million in Pension and PBOP Plan cash contributions, and changes in the timing of working capital items. These favorable impacts were more than offset by higher income tax payments in 2014 and the unfavorable cash flow impact resulting from lower recoveries from customers in 2014, as compared to 2013, relating to regulatory cost recovery tracking mechanisms.

- In 2014, we issued $725 million of new long-term debt consisting of $100 million by Yankee Gas on January 2, 2014, $300 million by NSTAR Electric on March 7, 2014, $250 million by CL&P on April 24, 2014 and $75 million by PSNH on October 14, 2014. In 2014, we repaid $575 million of existing long-term debt consisting of $75 million by Yankee Gas on January 1, 2014, $300 million by NSTAR Electric on April 15, 2014, $50 million by PSNH on July 15, 2014, and $150 million by CL&P on September 15, 2014. On January 15, 2015, NU parent issued $450 million of new long-term debt.

- In 2014, we had cash dividends on common shares of $475.2 million, compared with $462.7 million in 2013. On February 3, 2015, our Board of Trustees approved a common dividend payment of $0.4175 per share, payable on March 31, 2015 to shareholders of record as of March 2, 2015, which represents an increase of 6.4 percent over the dividend paid in December 2014, and is equivalent to a dividend on common shares of approximately $530 million on an annual basis.

- We project to make capital expenditures of approximately $8.4 billion from 2015 through 2018. Of the $8.4 billion, we expect to invest approximately $4.2 billion in our electric and natural gas distribution segments and $3.9 billion in our electric transmission segment. In addition, we project to invest approximately $360 million in information technology and facilities upgrades and enhancements. These projections do not include capital expenditures related to Access Northeast.

Overview

Consolidated: A summary of our earnings by business, which also reconciles the non-GAAP financial measures of consolidated non-GAAP earnings and EPS, as well as EPS by business, to the most directly comparable GAAP measures of consolidated Net Income Attributable to Controlling Interest and diluted EPS, is as follows:

	For the Years Ended December 31,					
	2014		2013		2012 [(1)]	
(Millions of Dollars, Except Per Share Amounts)	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net Income Attributable to Controlling Interest (GAAP)	$ 819.5	$ 2.58	$ 786.0	$ 2.49	$ 525.9	$ 1.89
Regulated Companies	$ 830.1	$ 2.61	$ 774.9	$ 2.45	$ 626.0	$ 2.25
NU Parent and Other Companies	11.5	0.04	24.9	0.08	7.5	0.03
Non-GAAP Earnings	841.6	2.65	799.8	2.53	633.5	2.28
Integration and Merger-Related Costs (after-tax)	(22.1)	(0.07)	(13.8)	(0.04)	(107.6)	(0.39)
Net Income Attributable to Controlling Interest (GAAP)	$ 819.5	$ 2.58	$ 786.0	$ 2.49	$ 525.9	$ 1.89

(1) Results include the operations of NSTAR beginning April 10, 2012.

Excluding the impact of integration costs, our 2014 earnings increased by $41.8 million, as compared to 2013. The increase was due primarily to lower operations and maintenance costs that impact earnings, which were primarily driven by lower labor and other employee-related costs, including approximately $30 million of non-tracked pension costs, and lower storm restoration costs, as well as higher firm natural gas sales volumes as a result of the colder weather in the first quarter of 2014, as compared to the first quarter of 2013. Partially offsetting this increase was the absence in 2014 of a favorable impact from the resolution of a state income tax audit in 2013, higher property taxes, higher depreciation expense at our regulated companies, and lower retail electric sales volumes as a result of cooler summer weather in 2014, as compared to the same period in 2013. Earnings were also unfavorably impacted by the 2014 after-tax net reserve of $22.4 million related to the 2014 FERC ROE orders, as compared to the 2013 after-tax reserve of $14.3 million related to the 2013 FERC ALJ initial decision in the FERC base ROE complaints. For further information, see "FERC Regulatory Issues – FERC Base ROE Complaints" in this *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

The 2014 and 2013 integration costs consisted of costs incurred for employee severance in connection with ongoing integration. As of December 31, 2014, NU employed approximately 8,250 employees, compared to 8,700 as of December 31, 2013. In addition, the 2014 integration costs included costs associated with our rebranding efforts, as well as costs related to facility closures across our service territories.

Regulated Companies: Our Regulated companies consist of the electric distribution, transmission, and natural gas distribution segments. Generation activities of PSNH and WMECO are included in our electric distribution segment. A summary of our segment earnings and EPS is as follows:

	For the Years Ended December 31,					
	2014		2013		2012 [(1)]	
(Millions of Dollars, Except Per Share Amounts)	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net Income – Regulated Companies (GAAP)	$ 830.1	$ 2.61	$ 774.9	$ 2.45	$ 572.8	$ 2.06
Electric Distribution	$ 462.4	$ 1.45	$ 427.0	$ 1.35	$ 343.4	$ 1.24
Transmission	295.4	0.93	287.0	0.91	249.7	0.89
Natural Gas Distribution	72.3	0.23	60.9	0.19	32.9	0.12
Net Income – Regulated Companies (Non-GAAP)	830.1	2.61	774.9	2.45	626.0	2.25
Merger-Related Costs (after-tax) [(2)]	-	-	-	-	(53.2)	(0.19)
Net Income - Regulated Companies (GAAP)	$ 830.1	$ 2.61	$ 774.9	$ 2.45	$ 572.8	$ 2.06

(1) Results include the operations of NSTAR beginning April 10, 2012.
(2) Merger-related costs are attributable to the electric distribution segment ($51.1 million) and the natural gas distribution segment ($2.1 million).

Our electric distribution segment earnings increased $35.4 million in 2014, as compared to 2013, due primarily to lower operations and maintenance costs that impact earnings, which were primarily driven by lower labor and other employee-related costs, including pension costs, and lower storm restoration costs. Partially offsetting these favorable earnings impacts, as compared to 2013, were higher property taxes and depreciation expense, lower retail electric sales volumes as a result of cooler summer weather in 2014, and the absence in 2014 of regulatory interest income on stranded cost deferrals in 2013.

Our transmission segment earnings increased $8.4 million in 2014, as compared to 2013, due primarily to a decrease in transmission segment state income tax expense and a higher transmission rate base as a result of an increased investment in our transmission infrastructure. These favorable impacts were partially offset by the after-tax net reserve of $22.4 million related to the 2014 FERC ROE orders, as compared to the $14.3 million after-tax reserve related to the 2013 FERC ALJ initial decision in the FERC base ROE complaints.

Our natural gas distribution segment earnings increased $11.4 million in 2014, as compared to 2013, due primarily to higher firm natural gas sales volumes and peak demand revenues resulting from colder weather in the first quarter of 2014 and additional natural gas heating customers.

A summary of our retail electric GWh sales volumes and percentage changes, as well as percentage changes in CL&P, NSTAR Electric, PSNH and WMECO retail electric GWh sales volumes, is as follows:

	For the Year Ended December 31, 2014 Compared to 2013						
	NU			CL&P	NSTAR Electric	PSNH	WMECO
	Sales Volumes (GWh)		Percentage Increase/	Percentage Increase/	Percentage	Percentage Increase/	Percentage
Electric	2014	2013	(Decrease)	(Decrease)	Decrease	Decrease	Decrease
Residential	21,317	21,896	(2.6)%	(2.8)%	(3.0)%	(1.1)%	(3.2)%
Commercial	27,449	27,787	(1.2)%	(1.3)%	(1.2)%	(0.8)%	(2.0)%
Industrial	5,676	5,648	0.5 %	2.5 %	(1.6)%	0.6 %	(2.5)%
Total	54,442	55,331	(1.6)%	(1.6)%	(1.8)%	(0.7)%	(2.6)%

A summary of our firm natural gas sales volumes in million cubic feet and percentage changes is as follows:

	For the Year Ended December 31, 2014 Compared to 2013		
	NU		
	Sales Volumes (million cubic feet)		Percentage
Firm Natural Gas	2014	2013	Increase
Residential	38,969	36,777	6.0%
Commercial	42,977	40,215	6.9%
Industrial	22,245	21,266	4.6%
Total	104,191	98,258	6.0%
Total, Net of Special Contracts (1)	99,500	94,083	5.8%

(1) Special contracts are unique to the customers who take service under such an arrangement and generally specify the amount of distribution revenue to be paid to Yankee Gas regardless of the customers' usage.

Weather, fluctuations in energy supply costs, conservation measures (including utility-sponsored energy efficiency programs), and economic conditions affect customer energy usage. Industrial sales are less sensitive to temperature variations than residential and commercial sales. In our service territories, weather impacts electric sales during the summer and electric and natural gas sales during the winter (natural gas sales are more sensitive to temperature variations than electric sales). Customer heating or cooling usage may not directly correlate with historical levels or with the level of degree-days that occur.

Our 2014 consolidated retail electric sales volumes were lower, as compared to 2013, due primarily to cooler summer weather in 2014. In 2014, cooling degree days were 13 percent lower in Connecticut and western Massachusetts, 17 percent lower in the Boston metropolitan area, and 23 percent lower in New Hampshire, as compared to 2013. Weather-normalized NU consolidated retail electric sales volumes decreased one percent in 2014, as compared to 2013. We believe the decrease was due primarily to an increase in customer conservation efforts primarily by our residential customers, including the impact of energy efficiency programs sponsored by CL&P, NSTAR Electric and WMECO.

For WMECO and CL&P (effective December 1, 2014), fluctuations in retail electric sales volumes do not impact earnings due to the regulatory commission approved revenue decoupling mechanisms. Distribution revenues are decoupled from their customer sales volumes. CL&P and WMECO reconcile their annual base distribution rate recovery to pre-established levels of baseline distribution delivery service revenues. Any difference between the allowed level of distribution revenue and the actual amount incurred during a 12-month period is adjusted through rates in the following period. The decoupling mechanism effectively breaks the relationship between sales volumes and revenues recognized. Prior to December 1, 2014, CL&P recognized LBR related to reductions in sales volume as a result of successful energy efficiency programs. LBR was recovered from retail customers through the FMCC. Effective December 1, 2014, CL&P no longer recognizes LBR due to its revenue decoupling mechanism. NSTAR Electric continues to recognize LBR through December 31, 2015 in accordance with the 2012 DPU-approved comprehensive merger settlement agreement with the Massachusetts Attorney General. For the year ended December 31, 2014, CL&P and NSTAR Electric recognized LBR of $5.3 million and $39.9 million, respectively.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales. In addition, they have benefited from historically favorable natural gas prices and customer growth across both operating companies. Our 2014 consolidated firm natural gas sales volumes, consisting of the firm natural gas sales volumes of Yankee Gas and NSTAR Gas, were higher, as compared to 2013, due primarily to colder weather in the first quarter of 2014, as compared to the same period in 2013, and increased customer growth in 2014, as compared to 2013. Weather-normalized NU consolidated firm natural gas sales volumes increased 2.9 percent in 2014, as compared to 2013.

NU Parent and Other Companies: NU parent and other companies, which include our unregulated businesses, had a net loss of $10.6 million in 2014, compared with earnings of $11.1 million in 2013. Excluding the impact of integration costs, NU parent and other companies earned $11.5 million in 2014, compared with $24.9 million in 2013. The earnings decrease in 2014 was due primarily to a higher effective tax rate and the absence in 2014 of the favorable impact from the resolution of the Connecticut state income tax audit.

Future Outlook

2015 EPS Guidance: We currently project 2015 earnings of between $2.75 per share and $2.90 per share, which excludes integration costs.

Liquidity

Consolidated: Cash and cash equivalents totaled $38.7 million as of December 31, 2014, compared with $43.4 million as of December 31, 2013.

On January 2, 2014, Yankee Gas issued $100 million of 4.82 percent Series L First Mortgage Bonds, due to mature in 2044. The proceeds, net of issuance costs, were used to repay the $75 million 4.80 percent Series G First Mortgage Bonds that matured on January 1, 2014 and to repay $25 million in short-term borrowings.

On March 7, 2014, NSTAR Electric issued $300 million of 4.40 percent debentures, due to mature in 2044. The proceeds, net of issuance costs, were used to repay the $300 million of 4.875 percent debentures that matured on April 15, 2014.

On April 24, 2014, CL&P issued $250 million of 4.30 percent 2014 Series A First Mortgage Bonds, due to mature in 2044. The proceeds, net of issuance costs, were used to repay short-term borrowings.

On July 15, 2014, PSNH repaid at maturity the $50 million of 5.25 percent Series L First Mortgage Bonds using short-term borrowings.

On September 15, 2014, CL&P repaid at maturity the $150 million of 4.80 percent 2004 Series A First Mortgage Bonds using short-term borrowings.

On October 14, 2014, PSNH issued $75 million of first mortgage bonds at a yield of 3.144 percent, due to mature in 2023. The first mortgage bonds are part of the same series of PSNH's existing 3.50 percent Series S First Mortgage Bonds that were initially issued in November 2013. The proceeds, net of issuance costs, were used to repay short-term borrowings.

On January 15, 2015, NU parent issued $150 million of 1.60 percent Series G Senior Notes, due to mature in 2018 and $300 million of 3.15 percent Series H Senior Notes, due to mature in 2025. The proceeds, net of issuance costs, were used to repay short-term borrowings outstanding under the NU commercial paper program.

On August 27, 2014, PURA approved CL&P's request to extend the authorization period for issuance of up to $366.4 million in long-term debt from December 31, 2014 to December 31, 2015.

NU parent, CL&P, PSNH, WMECO, NSTAR Gas and Yankee Gas are parties to a five-year $1.45 billion revolving credit facility. The revolving credit facility is to be used primarily to backstop NU parent's $1.45 billion commercial paper program. The commercial paper program allows NU parent to issue commercial paper as a form of short-term debt. Effective July 23, 2014, NU parent, CL&P, PSNH, WMECO, NSTAR Gas and Yankee Gas extended the expiration date of their joint revolving credit facility for one additional year to September 6, 2019. CL&P has a borrowing sublimit of $600 million, and PSNH and WMECO each have borrowing sublimits of $300 million. As of December 31, 2014 and 2013, NU parent had approximately $1.1 billion and $1.01 billion, respectively, in short-term borrowings outstanding under its commercial paper program, leaving $348.9 million and $435.5 million of available borrowing capacity as of December 31, 2014 and 2013, respectively. The weighted-average interest rate on these borrowings as of December 31, 2014 and 2013 was 0.43 percent and 0.24 percent, respectively, which is generally based on A2/P2 rated commercial paper. As of December 31, 2014, there were intercompany loans from NU parent of $133.4 million to CL&P, $90.5 million to PSNH and $21.4 million to WMECO. As of December 31, 2013, there were intercompany loans from NU parent of $287.3 million to CL&P and $86.5 million to PSNH.

NSTAR Electric has a five-year $450 million revolving credit facility. This facility serves to backstop NSTAR Electric's existing $450 million commercial paper program. Effective July 23, 2014, NSTAR Electric extended the expiration date of its revolving credit facility for one additional year to September 6, 2019. As of December 31, 2014 and 2013, NSTAR Electric had $302 million and $103.5 million, respectively, in short-term borrowings outstanding under its commercial paper program, leaving $148 million and $346.5 million of available borrowing capacity as of December 31, 2014 and 2013, respectively. The weighted-average interest rate on these borrowings as of December 31, 2014 and 2013 was 0.27 percent and 0.13 percent, respectively, which is generally based on A2/P1 rated commercial paper.

Each of NU, CL&P, NSTAR Electric, PSNH and WMECO use its available capital resources to fund its respective construction expenditures, meet debt requirements, pay operating costs, including storm-related costs, pay dividends and fund other corporate obligations, such as pension contributions. The current growth in NU's construction expenditures utilizes a significant amount of cash for projects that have a long-term return on investment and recovery period. In addition, NU's Regulated companies recover their electric and natural gas distribution construction expenditures as the related project costs are depreciated over the life of the assets. This impacts the timing of the revenue stream designed to fully recover the total investment plus a return on the equity portion of the cost and related financing costs. These factors have resulted in current liabilities exceeding current assets by approximately $442 million, $177 million, $133 million and $24 million at NU, CL&P, NSTAR Electric and WMECO, respectively, as of December 31, 2014.

As of December 31, 2014, $216.7 million of NU's obligations classified as current liabilities relates to long-term debt that will be paid in the next 12 months, consisting of $162 million for CL&P, $4.7 million for NSTAR Electric and $50 million for WMECO. The remaining $28.9 million of NU's obligations classified as current liabilities relates to fair value adjustments from the merger that will be amortized in the next 12 months and have no cash flow impact. NU, with its strong credit ratings, has several options available in the financial markets to repay or refinance these maturities with the issuance of new long-term debt. NU, CL&P, NSTAR Electric, PSNH and WMECO will reduce their short-term borrowings with cash received from operating cash flows or with the issuance of new long-term debt, determined considering capital requirements and maintenance of NU's credit

rating and profile. Management expects the future operating cash flows of NU, CL&P, NSTAR Electric, PSNH and WMECO, along with the access to financial markets, will be sufficient to meet any future operating requirements and capital investment forecasted opportunities.

Cash flows provided by operating activities totaled $1.64 billion in 2014, compared with $1.66 billion in 2013 and $1.16 billion in 2012. The 2014 operating cash flows were favorably impacted by approximately $132 million in DOE Damages proceeds resulting from the spent nuclear fuel litigation received by CL&P, NSTAR Electric, PSNH and WMECO from the Yankee Companies, the absence of 2013 cash disbursements for major storm restoration costs, the decrease of approximately $130 million in Pension and PBOP Plan cash contributions and changes in the timing of working capital items. These favorable impacts were more than offset by higher income tax payments in 2014 and the unfavorable cash flow impact resulting from lower recoveries from customers in 2014, as compared to 2013, relating to regulatory cost recovery tracking mechanisms. For further information on the spent nuclear fuel litigation, see Note 11C, "Commitments and Contingencies – Contractual Obligations – Yankee Companies," in this combined Annual Report on Form 10-K. The improved operating cash flows in 2013, as compared to 2012, were due primarily to the addition of NSTAR, a decrease in cash disbursements for storm restoration, and the absence in 2013 of cash disbursements related to customer bill credits and merger-related payments made in 2012. Partially offsetting these favorable cash flow impacts was an increase in Pension Plan cash contributions, increases in fuel inventories, and changes in traditional working capital amounts due primarily to the timing of accounts receivable and accounts payable.

A summary of our corporate credit ratings and outlooks by Moody's, S&P and Fitch is as follows:

	Moody's		S&P		Fitch	
	Current	Outlook	Current	Outlook	Current	Outlook
NU Parent	Baa1	Stable	A-	Positive	BBB+	Stable
CL&P	Baa1	Stable	A-	Positive	BBB+	Stable
NSTAR Electric	A2	Stable	A-	Positive	A	Stable
PSNH	Baa1	Stable	A-	Positive	BBB+	Stable
WMECO	A3	Stable	A-	Positive	BBB+	Stable

A summary of the current credit ratings and outlooks by Moody's, S&P and Fitch for senior unsecured debt of NU parent, NSTAR Electric, and WMECO and senior secured debt of CL&P and PSNH is as follows:

	Moody's		S&P		Fitch	
	Current	Outlook	Current	Outlook	Current	Outlook
NU Parent	Baa1	Stable	BBB+	Positive	BBB+	Stable
CL&P	A2	Stable	A	Positive	A	Stable
NSTAR Electric	A2	Stable	A-	Positive	A+	Stable
PSNH	A2	Stable	A	Positive	A	Stable
WMECO	A3	Stable	A-	Positive	A-	Stable

On January 31, 2014, Moody's upgraded corporate credit and securities ratings of NU, CL&P and PSNH by one level and WMECO by two levels. On April 7, 2014, Fitch affirmed the corporate credit ratings and outlook of NU, CL&P, NSTAR Electric, PSNH, WMECO and NSTAR Gas. On April 25, 2014, S&P affirmed the corporate credit ratings and revised the outlooks to positive from stable of NU, CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas.

In 2014, we had cash dividends on common shares of $475.2 million, compared with $462.7 million in 2013. On December 31, 2014, we paid a common dividend of $0.3925 per share, which was approved by our Board of Trustees on December 3, 2014, to shareholders of record as of December 15, 2014. On February 3, 2015, our Board of Trustees approved a common dividend payment of $0.4175 per share, payable on March 31, 2015 to shareholders of record as of March 2, 2015. The dividend represented an increase of 6.4 percent over the dividend paid in December 2014.

In 2014, CL&P, NSTAR Electric, PSNH, and WMECO paid $171.2 million, $253 million, $66 million, and $60 million, respectively, in common dividends to NU parent.

Investments in Property, Plant and Equipment on the statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension expense. In 2014, investments for NU, CL&P, NSTAR Electric, PSNH, and WMECO were $1.6 billion, $515.7 million, $465 million, $256.2 million, and $116.2 million, respectively.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portions of pension expense (all of which are non-cash factors), totaled $1.7 billion in 2014, $1.6 billion in 2013, and $1.5 billion in 2012. These amounts included $58.3 million in 2014, $44.7 million in 2013, and $43.1 million in 2012, related to information technology and facilities upgrades and enhancements, primarily at NUSCO and The Rocky River Realty Company.

Access Northeast: On September 16, 2014, NU and Spectra Energy Corp announced Access Northeast, a natural gas pipeline expansion project. Access Northeast will enhance the Algonquin and Maritimes pipeline systems using existing routes and is expected to be capable of delivering approximately one billion cubic feet of natural gas per day to New England. NU and Spectra Energy Corp will have equal ownership interest in the project with the option of additional investors joining in the future. On February 18, 2015, NU, Spectra Energy Corp and National Grid announced the addition of National Grid as a co-developer in the project for a total ownership interest of 20 percent, with NU and Spectra Energy Corp each owning 40 percent. The total project cost, subject to FERC approval, is expected to be approximately $3 billion and has an anticipated in-service date of November 2018.

On December 8, 2014, NU and Spectra Energy Corp announced an alliance with Iroquois Gas Transmission for the Access Northeast project. This alliance will provide New England natural gas distribution companies and generators with additional access to natural gas supplies from multiple, diverse receipt points along the Algonquin pipeline system, including the Iroquois pipeline system.

Transmission Business: Overall, transmission business capital expenditures increased by $41.1 million in 2014, as compared to 2013. A summary of transmission capital expenditures by company is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012 [1]
CL&P	$ 259.2	$ 211.9	$ 182.5
NSTAR Electric	223.8	220.8	160.7
PSNH	120.8	99.7	55.7
WMECO	68.5	87.2	214.7
NPT	28.3	39.9	35.4
Total Transmission Segment	$ 700.6	$ 659.5	$ 649.0

[1] Results include the transmission capital expenditures of NSTAR Electric beginning April 10, 2012.

NEEWS: GSRP, the first, largest and most complicated project within the NEEWS family of projects, was fully energized on November 20, 2013. As of December 31, 2014, CL&P and WMECO have placed $642 million in service.

The Interstate Reliability Project (IRP) is the second major NEEWS project. It includes CL&P's construction of an approximately 40-mile, 345 kV overhead line from Lebanon, Connecticut to the Connecticut-Rhode Island border in Thompson, Connecticut where it will connect to transmission enhancements being constructed by National Grid in Rhode Island and Massachusetts. All siting approvals have been received and construction is underway in all three states. NU's portion of the cost is estimated to be $218 million, and IRP was approximately 78 percent complete as of December 31, 2014. As of December 31, 2014, CL&P had placed $35 million in service. We expect to complete IRP by the end of 2015.

The Greater Hartford Central Connecticut Study (GHCC) includes the reassessment of the Central Connecticut Reliability Project and continues to make progress. The final need results showed existing and worsening severe regional and local thermal overloads and voltage violations within each of the areas studied and across the interfaces of those areas. These results were presented to the ISO-NE Planning Advisory Committee in November 2013. On July 15, 2014, ISO-NE presented the preferred transmission solutions to its Planning Advisory Committee. These solutions are comprised of many 115 kV upgrades and are expected to cost approximately $350 million and be placed in service from 2016 through 2018. We expect to begin work on the initial solutions in late 2015 and complete GHCC-related work in 2018.

Included as part of NEEWS are several associated reliability related projects, $96 million of which have been placed in service. As of the second quarter of 2014, all construction on the associated reliability related projects was completed.

Through December 31, 2014, CL&P and WMECO capitalized $351.5 million and $573.6 million, respectively, in costs associated with NEEWS, of which $98.7 million and $6.6 million, respectively, were capitalized in 2014. Included in the NEEWS amounts are costs for IRP, of which CL&P capitalized $168.8 million in costs through December 31, 2014, and $95.8 million related to costs capitalized in 2014.

Northern Pass: Northern Pass is NU's planned HVDC transmission line from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. Northern Pass will interconnect at the Québec-New Hampshire border with a planned HQ HVDC transmission line. NPT received ISO-NE approval under Section I.3.9 of the ISO tariff in 2013. The DOE continues to work on the draft Environmental Impact Statement (EIS) for Northern Pass. This includes a review of our proposed route and various alternative routes. We currently expect the DOE to issue the draft EIS in April 2015. We expect to file the state permit application in mid-2015 after receipt of the draft EIS. The $1.4 billion project is subject to comprehensive federal and state public permitting processes and is expected to be operational in the second half of 2018.

Greater Boston Reliability Solutions: NSTAR Electric and PSNH expect to implement a series of new transmission projects over the next five years to enhance the region's system reliability. On February 12, 2015, ISO-NE selected NU's and National Grid's proposed Greater Boston and New Hampshire Solution (Solution) as its preferred option because it is significantly less expensive than an alternate proposal and has superior performance criteria. The Solution consists of a portfolio of important electric transmission upgrades encompassing the Merrimack Valley and metropolitan Boston areas of southern New Hampshire and eastern Massachusetts. Our estimated investment in the Solution chosen by ISO-NE is $489 million and we will now pursue the necessary regulatory approvals.

Distribution Business: A summary of distribution capital expenditures by company is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2014	2013	2012 [(1)]
CL&P:			
Basic Business	$ 120.2	$ 60.9	$ 69.2
Aging Infrastructure	118.0	160.7	177.8
Load Growth	66.3	76.9	65.8
Total CL&P	304.5	298.5	312.8
NSTAR Electric:			
Basic Business	99.0	98.5	47.3
Aging Infrastructure	104.2	110.6	111.5
Load Growth	43.1	53.6	17.4
Total NSTAR Electric	246.3	262.7	176.2
PSNH:			
Basic Business	62.1	22.7	25.3
Aging Infrastructure	45.3	50.5	50.2
Load Growth	27.1	29.3	20.2
Total PSNH	134.5	102.5	95.7
WMECO:			
Basic Business	19.0	7.9	12.7
Aging Infrastructure	16.1	24.6	18.5
Load Growth	6.1	9.2	6.5
Total WMECO	41.2	41.7	37.7
Total - Electric Distribution (excluding Generation)	726.5	705.4	622.4
Other Distribution	-	0.7	0.1
PSNH Generation	13.1	9.7	29.9
WMECO Generation	7.6	4.5	0.7
Total - Natural Gas	193.7	175.2	162.9
Total Distribution Segment	$ 940.9	$ 895.5	$ 816.0

(1) Results include the electric and natural gas distribution capital expenditures of NSTAR beginning April 10, 2012.

For the electric distribution business, basic business includes the purchase of meters, tools, vehicles, information technology, transformer replacements, equipment facilities, and the relocation of plant. Aging infrastructure relates to reliability and the replacement of overhead lines, plant substations, underground cable replacement, and equipment failures. Load growth includes requests for new business and capacity additions on distribution lines and substation additions and expansions.

Natural Gas Business Expansion and Enhancement: In 2013, in accordance with Connecticut law and regulation, PURA approved a comprehensive joint natural gas infrastructure expansion plan (expansion plan) filed by Yankee Gas and other Connecticut natural gas distribution companies. The expansion plan described how Yankee Gas expects to add approximately 82,000 new natural gas heating customers over the next 10 years. Yankee Gas estimates that its portion of the plan will cost approximately $700 million over 10 years. In January 2015, PURA approved a joint settlement agreement proposed by Yankee Gas and other Connecticut natural gas distribution companies and regulatory agencies that clarified the procedures and oversight criteria applicable to the expansion plan.

On October 31, 2014, pursuant to new legislation, NSTAR Gas filed the Gas System Enhancement Program (GSEP) with the DPU. NSTAR Gas' program accelerates the replacement of certain natural gas distribution facilities in the system within 25 years. The GSEP includes a new tariff that provides NSTAR Gas an opportunity to collect the costs for the program on an annual basis through a newly designed reconciling factor to be approved by the DPU. We expect a decision on the program in April 2015. We have projected capital expenditures of approximately $200 million for the period 2015 through 2018 for the GSEP, which are consistent with our request in the NSTAR Gas rate case application currently before the DPU.

Projected Capital Expenditures: A summary of the projected capital expenditures for the Regulated companies' electric transmission and for the total electric distribution, generation, and natural gas distribution businesses for 2015 through 2018, including information technology and facilities upgrades and enhancements on behalf of the Regulated companies, is as follows:

	Years				
(Millions of Dollars)	2015	2016	2017	2018	2015-2018 Total
CL&P Transmission	$ 214	$ 241	$ 258	$ 158	$ 871
NSTAR Electric Transmission	231	262	236	295	1,024
PSNH Transmission	133	76	73	19	301
WMECO Transmission	128	80	34	8	250
NPT	34	309	620	466	1,429
Total Transmission	$ 740	$ 968	$ 1,221	$ 946	$ 3,875
Electric Distribution	$ 755	$ 778	$ 758	$ 748	$ 3,039
Generation	38	20	15	15	88
Natural Gas	228	256	275	300	1,059
Total Distribution	$ 1,021	$ 1,054	$ 1,048	$ 1,063	$ 4,186
Information Technology and All Other	$ 90	$ 92	$ 94	$ 83	$ 359
Total	$ 1,851	$ 2,114	$ 2,363	$ 2,092	$ 8,420

The projections do not include capital expenditures related to Access Northeast. Actual capital expenditures could vary from the projected amounts for the companies and years above.

FERC Regulatory Issues

FERC Base ROE Complaints:
First Complaint: On September 30, 2011, a complaint was filed jointly at FERC under Sections 206 and 306 of the Federal Power Act (the "first complaint") by several New England state attorneys general, state regulatory commissions, consumer advocates and other parties (the "Complainants"). The Complainants alleged that the base ROE of 11.14 percent that has been utilized since 2006 in the calculation of formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by NETOs, including CL&P, NSTAR Electric, PSNH and WMECO, was unjust and unreasonable and asserted that the rate was excessive due to changes in the capital markets. Complainants sought an order to reduce the base ROE prospectively from the date of a final FERC order, and for the 15-month period October 1, 2011 to December 31, 2012 (the "first complaint refund period"), and to require refunds. The FERC set the case for trial before a FERC ALJ after settlement negotiations were unsuccessful in August 2012.

On August 6, 2013, the FERC ALJ issued an initial decision on the first complaint finding that the base ROE in effect during the first complaint refund period was not reasonable and recommended separate base ROEs for the first complaint refund period of 10.6 percent and for the period beginning when FERC issues its final decision (the "prospective period") of 9.7 percent, leaving policy considerations and additional adjustments to the FERC. In 2013, the Company recorded reserves at its electric subsidiaries to recognize the potential financial impact from the FERC ALJ's initial decision for the first complaint refund period.

On June 19, 2014, FERC issued an order on the first complaint partially affirming and partially reversing the FERC ALJ's initial decision. FERC set a single tentative base ROE of 10.57 percent for the first complaint refund period and prospective period. FERC also modified its traditional methodology by adopting a two-step discounted cash flow analysis consistent with the method that it utilizes to determine the ROEs of both natural gas and oil pipeline projects. Using this methodology, FERC determined a new zone of reasonableness of 7.03 percent to 11.74 percent, and set the tentative base ROE halfway between the midpoint and the top of the zone of reasonableness. FERC also stated that a utility's "total ROE, inclusive of transmission incentive ROE adders" should not exceed the top of the new zone of reasonableness produced by this methodology. FERC instituted a paper hearing on the long-term growth rate portion of the methodology (the "paper hearing"). Rehearing requests on this new methodology were filed in July 2014, and briefs were filed in August and September 2014 by the parties on the appropriate long-term growth rate.

On October 16, 2014, the FERC issued an order in the paper hearing, which confirmed that the base ROE should be set at 10.57 percent and that a utility's total or maximum ROE should not exceed the top of the new zone of reasonableness (11.74 percent). The FERC ordered the NETOs to provide refunds to customers for the first complaint refund period, and set the prospective new base ROE at this time. In November 2014, the NETOs requested rehearing and clarification from FERC. In late 2014, the NETOs made a compliance filing, and began refunding amounts from the first complaint period, inclusive of incentive ROE adders that exceeded the 11.74 percent as compared to the total company transmission ROE. Complainants have challenged the compliance filing.

In 2014, the Company recorded additional reserves at its electric subsidiaries to recognize the potential financial impact from the FERC's orders.

Second Complaint: On December 27, 2012, a second complaint was filed jointly at FERC by several additional consumer groups and municipal parties (the "second complaint"), challenging the NETOs' existing base ROE, requesting FERC to reduce the NETOs' base ROE prospectively from the date of the final FERC order and seeking refunds for the 15-month period of December 27, 2012 to March 27, 2014 (the "second complaint refund period").

On June 19, 2014, FERC issued an order finding that the second complaint raised issues of material fact, and setting the complaint for settlement or hearing. On July 21, 2014, the NETOs filed a rehearing request in this proceeding. On October 24, 2014, the FERC assigned the case for trial before a FERC ALJ after settlement negotiations were unsuccessful. The FERC ALJ set a trial date beginning June 8, 2015, and indicated he could issue an initial decision on or before October 26, 2015. This schedule was subsequently modified by a November 24, 2014 order on the third complaint (see below). In 2014, the Company recorded reserves at its electric subsidiaries to recognize the potential financial impact from the FERC's June 19th order for the second complaint refund period.

Third Complaint: On July 31, 2014, a third complaint was filed at FERC (the "third complaint") by most of the Complainants to the first and second complaints, claiming that the base ROE and incentive adders exceed the range of permissible ROEs, requesting FERC to reduce the NETOs' base ROE prospectively from the date of a final FERC order, and seeking refunds for the 15-month period of July 31, 2014 to October 31, 2015 (the "third complaint refund period"). On November 24, 2014, FERC issued an order finding that the third complaint raised issues of material fact and set the case for trial. In this order, FERC also consolidated the third complaint with the second complaint for purposes of hearing and decision. Due to the establishment of two refund periods, the FERC also stated that it is appropriate for the parties to litigate a separate ROE for each refund period. On December 24, 2014, the NETOs filed for rehearing of this order. The trial judge has set a hearing beginning June 23, 2015 for the two complaints. The trial judge's recommended initial decision is expected by November 30, 2015 with a FERC order issued by September 30, 2016.

Rehearing requests of NETOs that were filed in all three complaint proceedings have not yet been acted upon by FERC. At this time, the Company cannot determine the outcome of these rehearing requests.

Cumulative Reserves: The following is a summary of the cumulative pre-tax reserves (excluding interest) that the Company established in 2013 and 2014 to recognize the potential financial impacts of the first and second complaints. The Company is unable to determine any amount related to the third complaint.

	NU For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total
1st Complaint - Base ROE	$ 23.7	$ 1.2	$ 24.9
2nd Complaint - Base ROE	-	27.4	27.4
Incentive ROE (1st and 2nd Complaint)	-	8.4	8.4
Cumulative Reserve	$ 23.7	$ 37.0	$ 60.7

	CL&P For the Years Ended December 31,			NSTAR Electric For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total	2013	2014	Total
1st Complaint - Base ROE	$ 12.8	$ 0.5	$ 13.3	$ 5.7	$ 0.4	$ 6.1
2nd Complaint - Base ROE	-	13.5	13.5	-	7.5	7.5
Incentive ROE (1st and 2nd Complaint)	-	6.7	6.7	-	-	-
Cumulative Reserve	$ 12.8	$ 20.7	$ 33.5	$ 5.7	$ 7.9	$ 13.6

	PSNH For the Years Ended December 31,			WMECO For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total	2013	2014	Total
1st Complaint - Base ROE	$ 2.3	$ 0.1	$ 2.4	$ 2.9	$ 0.2	$ 3.1
2nd Complaint - Base ROE	-	2.7	2.7	-	3.7	3.7
Incentive ROE (1st and 2nd Complaint)	-	-	-	-	1.7	1.7
Cumulative Reserve	$ 2.3	$ 2.8	$ 5.1	$ 2.9	$ 5.6	$ 8.5

As of December 31, 2014, the cumulative reserves above do not reflect refunds totaling $4.8 million at NU, $2.7 million at CL&P, $1 million at NSTAR Electric, $0.5 million at PSNH and $0.6 million at WMECO for the first complaint refund period.

In the fourth quarter of 2014, we finalized our reserve analysis based on the October FERC order and our subsequent refund filing. As a result, the net aggregate after-tax charge to 2014 earnings resulting from the June 19, 2014 and October 16, 2014 FERC orders totaled $22.4 million at NU, $12.4 million at CL&P, $4.9 million at NSTAR Electric, $1.7 million at PSNH and $3.4 million at WMECO. In 2013, the aggregate after-tax charge to earnings totaled $14.3 million at NU, $7.7 million at CL&P, $3.4 million at NSTAR Electric, $1.4 million at PSNH and $1.8 million at WMECO.

Regulatory Developments and Rate Matters

Electric and Natural Gas Base Distribution Rates:

Each NU utility subsidiary is subject to the regulatory jurisdiction of the state in which it operates: CL&P and Yankee Gas operate in Connecticut and are subject to PURA regulation; NSTAR Electric, WMECO and NSTAR Gas operate in Massachusetts and are subject to DPU regulation; and PSNH operates in New Hampshire and is subject to NHPUC regulation.

In Connecticut, CL&P distribution rates were established in a 2014 PURA approved rate case. See *Connecticut – Distribution Rates* in this *Regulatory Developments and Rate Matters* section for further information. Yankee Gas distribution rates were established in a 2011 PURA approved rate case.

In Massachusetts, electric utility companies are required to file at least one distribution rate case every five years and natural gas companies to file at least one distribution rate case every 10 years, and those companies are limited to one settlement agreement in any 10-year period. Pursuant to the April 2012 DPU-approved Massachusetts comprehensive merger settlement agreements, NSTAR Electric, WMECO and NSTAR Gas are subject to a base distribution rate freeze through December 31, 2015. On December 17, 2014, NSTAR Gas filed an application with the DPU to amend base distribution rates, effective January 1, 2016.

In New Hampshire, PSNH is currently operating under the 2010 NHPUC approved distribution rate case settlement, which is effective through June 30, 2015. Under the settlement, PSNH is permitted to file a request to collect certain exogenous costs and step increases on an annual basis. See *New Hampshire - Distribution Rates* in this *Regulatory Developments and Rate Matters* section for further information.

Major Storms:

CL&P, NSTAR Electric, PSNH and WMECO experienced several significant storm events, including Tropical Storm Irene in 2011, the October 2011 snowstorm, Storm Sandy in 2012, and the February 2013 blizzard. As a result of these storm events, each company suffered extensive damage to its distribution and transmission systems resulting in customer outages. Each company incurred significant costs to repair damage and restore customers' service. In addition, on November 26, 2014, a snowstorm caused damage to the electric delivery systems of PSNH and WMECO. This snowstorm resulted in estimated deferred storm restoration costs of approximately $23 million at PSNH and approximately $3 million at WMECO.

The magnitude of these storm restoration costs met the criteria for cost deferral in Connecticut, Massachusetts, and New Hampshire. As a result, the storms had no material impact on the results of operations of CL&P, NSTAR Electric, PSNH and WMECO. We believe the storm restoration costs were prudent and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery process. Each electric utility has sought, or is seeking, recovery of its deferred storm restoration costs through its applicable regulatory recovery process. As of December 31, 2014, all CL&P deferred storm costs have been reviewed and approved for recovery in distribution rates, NSTAR Electric received DPU approval for recovery of $34.2 million of deferred storm costs related to Tropical Storm Irene in 2011 and the October 2011 snowstorm, PSNH received an NHPUC audit report, which found no exception with storm costs from 2011 through March 2013, and WMECO received DPU approval to begin recovering the October 2011 snowstorm and 2012 Storm Sandy restoration costs, of which the DPU approved the majority of deferred storm costs through 2011.

DPU Storm Penalties: In December 2012, in separate orders issued by the DPU, the DPU ordered penalties of $4.1 million and $2 million for NSTAR Electric and WMECO, respectively, related to the electric utilities' responses to Tropical Storm Irene and the October 2011 snowstorm, which were refunded to their customers. In December 2012, NSTAR Electric and WMECO each filed appeals with the SJC arguing the DPU penalties should be vacated. On September 4, 2014, the SJC vacated $2 million of NSTAR Electric's $4.1 million penalties, as it did not believe that substantial evidence existed to support such penalties, while it upheld the WMECO penalties. Subsequently, the DPU reinstated approximately $0.4 million of NSTAR Electric storm penalties pursuant to a December 22, 2014 order.

Connecticut:

Distribution Rates: On June 9, 2014, CL&P filed an application with PURA to amend distribution rates, effective December 1, 2014. The application included an increase to base distribution rates, as well as increases for the recovery of previously approved 2011 and 2012 deferred storm restoration costs and previously approved electric system resiliency costs. After the legal briefing process, CL&P updated its requested increase to reflect a reduction to the storm cost recovery amounts. The reduction primarily related to applying the impact of the $65.4 million DOE Phase II Damages proceeds received on June 1, 2014 to the total deferred storm restoration costs of $365 million, as ordered by PURA on June 17, 2014.

On December 17, 2014, PURA issued a final order and approved a total distribution rate increase of $134 million, which includes an authorized ROE of 9.02 percent for the first twelve month period and 9.17 percent thereafter. The 2011 and 2012 storm costs were approved in their entirety, to be recovered over a six-year period, and adjustments to storm cost recovery and system resiliency cost recovery reflect the lower approved ROE. PURA granted a re-opener to the rate application for further review of the appropriate treatment of deferred income taxes for rate base purposes. If PURA concludes that CL&P's treatment of its deferred taxes for rate base purposes is correct, it would result in an additional annual increase to total distribution rates of $22 million. CL&P is currently responding to information requests and has provided additional information with respect to the treatment of deferred income taxes for rate base purposes and expects a decision no later than the third quarter of 2015.

The PURA also approved the establishment of a revenue decoupling reconciliation mechanism, effective December 1, 2014, whereby actual base distribution rate recovery is reconciled with pre-established revenue requirement level on an annual basis. Any difference between the allowed level of distribution revenue and the actual amount incurred in a calendar year is adjusted through rates in the following year. The baseline allowed distribution revenue is $1.041 billion, which will remain constant until CL&P's next rate case. With the implementation of the decoupling mechanism, LBR will no longer be recognized effective December 1, 2014, and CL&P will not experience significant fluctuations to its base distribution revenues regardless of the impact of weather and energy efficiency by its customers.

The PURA also allowed CL&P recovery of $31.1 million in 2013 storm costs and residual 2012 Storm Sandy costs over a seven-year period beginning December 1, 2014.

CL&P 2014 Storm Order: On March 12, 2014, PURA approved recovery of $365 million of deferred storm restoration costs (with carrying charges) associated with five major storms that occurred in 2011 and 2012 and ordered CL&P to capitalize approximately $18 million of the deferred storm restoration costs as utility plant, which will be recovered through depreciation expense in future rate proceedings. On December 1, 2014, CL&P began recovering approximately $300 million in its distribution rates over a six-year period, which was net of $65.4 million of DOE Phase II Damages proceeds. The remaining costs were either disallowed or are probable of recovery from other sources. These costs did not have a material impact on CL&P's financial position or results of operations.

CL&P Standard Service and Last Resort Service Rates: CL&P's residential and small to intermediate commercial and industrial customers who do not choose competitive energy suppliers are served under SS rates, and large commercial and industrial customers who do not choose competitive energy suppliers are served under LRS rates. Effective January 1, 2015, the PURA approved an increase to CL&P's energy supply portion of the total average SS rate to 12.446 cents per kWh and the energy supply portion of the total average LRS rate to 17.714 cents per kWh. These changes were due primarily to the market conditions for the procurement of energy. The SS and LRS rates reflect CL&P's costs to procure energy for its customers. Adjustments to these rates do not impact earnings, as CL&P is fully recovering the costs of its SS and LRS services from customers.

CL&P CTA and SBC Reconciliation: CL&P filed its 2013 CTA and SBC reconciliation on March 31, 2014, which compared CTA and SBC billed revenues to revenue requirements, as required by PURA. The 2013 reconciliation filing produced net over recoveries of $16.9 million and $4.3 million for the CTA and SBC, respectively, and was approved by PURA.

CL&P FMCC Filing: CL&P files with PURA its FMCC filing, which reconciles actual FMCC revenues and charges and GSC revenues and expenses. The filing identifies a total net over or under recovery, which includes the remaining uncollected or non-refunded portions from previous filings. On February 3, 2014, CL&P filed with PURA its FMCC filing for the period July 1, 2013 through December 31, 2013. The filing identified a total net over recovery through December 31, 2013 of $24.1 million and was approved by PURA.

CL&P Conservation Adjustment Mechanism: In 2012, CL&P filed an application with PURA for the establishment of a CAM. The CAM would collect the costs associated with expanded energy efficiency programs beyond that already collected through the statutory charge and the revenues lost because of the expanded energy efficiency programs. In 2013, DEEP approved CL&P's request of an expanded conservation spending budget and reiterated that PURA is directed to approve a CAM to fund the expanded conservation budget. The PURA approved a CAM effective January 1, 2014 subject to a future review of its revenue and expense reconciliation filing to be submitted by CL&P. CL&P has continued its approved January 1, 2014 CAM rate through 2015.

Massachusetts:

Basic Service Rates: Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through Basic Service for those customers who choose not to buy energy from a competitive energy supplier. Basic Service rates are reset every six months (every three months for large commercial and industrial customers). NSTAR Electric and WMECO fully recover their energy costs through DPU-approved regulatory rate mechanisms.

2015 Annual Reconciliation Filing: In the fourth quarter of 2014, NSTAR Electric and WMECO filed separately their respective 2015 annual cost recovery mechanisms, including the mechanisms to collect the costs to provide retail transmission, energy supply and energy efficiency services to its customers as well as the costs related to pension and other post-retirement employee benefit costs. The reconciliation filings compared the total revenues to revenue requirements related to these services. In December 2014, the DPU issued a final decision approving the rates as filed, subject to future review and reconciliation.

Energy Efficiency Plans: In accordance with Massachusetts law passed in 2008 known as the Green Communities Act, natural gas and electric distribution companies must file three-year energy efficiency plans, which were initially filed by NSTAR Electric and WMECO, and approved by the DPU, in 2010 covering the period 2010 through 2012. The NSTAR Electric and WMECO three-year plans covering the period 2013 through 2015 were approved by the DPU in 2013. Distribution companies that do not yet have rate decoupling mechanisms in place, like NSTAR Electric, include LBR rate adjustment mechanisms in order to offset reduced distribution rate revenues as a result of successful energy efficiency programs. NSTAR Electric's LBR rate adjustment mechanism is in place through December 31, 2015.

DPU Safety and Reliability Programs (CPSL): The CPSL program allows NSTAR Electric to recover $15 million per year related to DPU approved safety and reliability programs, which are designed to mitigate stray voltage and repair and replace portions of the system to increase and enhance customer safety. This annual level of recovery was established by the 2012 DPU-approved comprehensive merger settlement agreement with the Massachusetts Attorney General. The CPSL program will expire on December 31, 2015.

2014 Comprehensive Settlement Agreement: On December 31, 2014, NSTAR Electric, NSTAR Gas and the Massachusetts Attorney General filed a comprehensive settlement agreement with the DPU. The comprehensive settlement agreement included resolution of the outstanding NSTAR Electric CPSL program filings for the periods 2006 through 2011, the NSTAR Electric and NSTAR Gas PAM and energy efficiency-related customer billing adjustments reported in 2012, and the NSTAR Electric energy efficiency program filings regarding LBR for the periods 2008 through 2011. If approved by the DPU, NSTAR Electric and NSTAR Gas will be required to refund a total of $44.7 million to their respective customers, which was included in our regulatory liabilities as of December 31, 2014. Upon the DPU's approval, we will adjust our regulatory liabilities, which we expect will result in an after-tax benefit of approximately $14 million. We expect a response from the DPU in the first quarter of 2015.

Basic Service Bad Debt Adder: In accordance with a generic 2005 DPU order, electric utilities in Massachusetts recover the energy-related portion of bad debt costs in their Basic Service rates. In 2007, NSTAR Electric filed its 2006 Basic Service reconciliation with the DPU proposing an adjustment related to the increase of its Basic Service bad debt charge-offs. The DPU issued an order approving the implementation of a revised Basic Service rate but instructed NSTAR Electric to reduce distribution rates by an amount equal to the increase in its Basic Service bad debt charge-offs. This adjustment to NSTAR Electric's distribution rates would eliminate the fully reconciling nature of the Basic Service bad debt adder.

In 2010, NSTAR Electric filed an appeal of the DPU's order with the SJC. NSTAR Electric's position was that it had fully removed the collection of energy-related bad debt costs from its distribution rates effective January 1, 2006. Therefore, no further adjustment to distribution rates was warranted. In 2012, the SJC vacated the DPU order and remanded the matter to the DPU for further review.

As of December 31, 2014, NSTAR Electric has a total deferred regulatory asset of approximately $33 million of costs associated with energy-related bad debt.

On January 7, 2015, the DPU issued an order on remand stating that NSTAR Electric had, in fact, removed energy-related bad debt costs from distribution rates effective January 1, 2006. The DPU order approved NSTAR Electric's 2005 and 2006 reconciliation filings and ordered NSTAR Electric and the Massachusetts Attorney General to collaborate on the submission of a proposal for the reconciliation of energy-related bad debt costs for the open years of 2007 through 2014 by April 7, 2015. Management expects to present a proposal to the Attorney General in the first quarter of 2015 with a decision from the DPU later in 2015.

Long-Term Wind Contracts: On January 6, 2015, NSTAR Electric terminated a 15-year renewable energy contract with Cape Wind Associates, LLC due to Cape Wind Associates, LLC's failure to fulfill obligations under the contract. Under this contract, NSTAR Electric would have purchased 129 MW of renewable energy from an offshore wind energy facility, which was scheduled to achieve commercial operation by December 2016. As a result, and in accordance with the 2012 DPU-approved comprehensive merger settlement agreement with the DOER, NSTAR Electric will issue a request for proposal (RFP) for new Massachusetts RPS Class I qualified renewable contracts with a term of at least 15 years, for approximately 2 percent of its electric load requirement. The RFP shall be issued no later than March 31, 2016 in accordance with the provisions of the procurement obligations of the Green Communities Act.

NSTAR Gas Distribution Rates: On December 17, 2014, NSTAR Gas filed an application with the DPU requesting an increase in rates, effective January 1, 2016. NSTAR Gas requested an increase in base distribution rates of $33.9 million. We expect a final decision in the fourth quarter of 2015.

New Hampshire:

Distribution Rates: In 2014, PSNH filed for a distribution rate decrease in accordance with the Earnings Sharing Agreement addressed in the 2010 NHPUC approved distribution rate case settlement. On June 27, 2014, the NHPUC approved a one year decrease to distribution rates of $1.3 million, effective July 1, 2014.

ES and SCRC Rates: On December 15, 2014, PSNH updated its request with the NHPUC to adjust its ES and SCRC rates effective January 1, 2015. PSNH's update proposed to increase the current ES and SCRC billing rates to reflect projected costs for 2015. On December 29, 2014, the NHPUC approved the request. The approved energy supply portion of the 2015 rate is 10.56 cents per kWh and the SCRC rate for 2015 is 0.110 cents per kWh.

Clean Air Project Prudence Proceeding: The Clean Air Project, which involved the installation of wet scrubber technology at PSNH's Merrimack coal-fired generation station in Bow, New Hampshire, pursuant to state law, was placed in service in September 2011. In November 2011, the NHPUC opened a docket to review the Clean Air Project, including the establishment of temporary rates for near-term recovery of Clean Air Project costs, a prudence review of PSNH's overall construction program, and establishment of permanent rates for recovery of prudently incurred Clean Air Project costs. In April 2012, the NHPUC issued an order authorizing temporary rates to recover a significant portion of the Clean Air Project costs. The docket remains open to conduct a comprehensive prudence review of the Clean Air Project and the establishment of permanent rates. The temporary rates will remain in effect until permanent rates allowing full recovery of all prudently incurred costs are approved. At that time, the NHPUC will reconcile recoveries collected under the temporary rates with approved permanent rates.

The NHPUC concluded its prudence hearings in October 2014. On December 26, 2014, PSNH requested that the NHPUC stay this proceeding in order to allow discussions to take place with other significant parties to determine whether a collaborative resolution of all issues was achievable. The New Hampshire Governor and Senate Majority Leader expressed support for this effort. On January 15, 2015, the NHPUC issued an order granting the motion to stay in this proceeding, and settlement discussions have ensued.

While we cannot predict with certainty the outcome of the Clean Air Project prudence review, we believe all costs were incurred appropriately and continue to remain probable of recovery.

Generation: In 2013, the NHPUC opened a docket to investigate market conditions affecting PSNH's ES rate, how PSNH will maintain just and reasonable rates in light of those conditions, and any impact of PSNH's generation ownership on the New Hampshire competitive electric market. The NHPUC accepted from the NHPUC Staff a "Report on Investigation into Market Conditions, Default Service Rate, Generation Ownership and Impact on the Competitive Electricity Market." The report recommended that the NHPUC examine whether default service rates remain sustainable on a going forward basis, define "just and reasonable" with respect to default service in the context of competitive retail markets, analyze the current and expected value of PSNH's generating units, and identify means to mitigate and address stranded cost recovery.

In 2013, the NHPUC issued a Request for Proposal to hire a valuation expert to determine the market value of PSNH's generation assets and entitlements. The State of New Hampshire Legislative Oversight Committee on Electric Utility Restructuring (Oversight Committee) requested that the NHPUC conduct an analysis to determine whether it is now in the economic interest of PSNH's retail customers for PSNH to divest its interest in generation plants. The Oversight Committee asked for a preliminary report on the findings by April 1, 2014 that would include at a minimum the NHPUC Staff's position, the analysis of the valuation expert, and any recommendations for legislation that may be needed concerning divestiture or otherwise related to this issue.

On April 1, 2014, the NHPUC staff issued a "Preliminary Status Report Addressing the Economic Interest of PSNH's Retail Customers as it Relates to the Potential Divestiture of PSNH's Generating Plants," which included a consultant's analysis of the fair market value of PSNH generating assets and long-term power purchase contracts. The consultant's analysis estimated the fair market value of PSNH's generation assets to be $225 million as of December 31, 2013 and compared that amount to a stated net book value of $660 million, implying potential "stranded costs" of approximately $435 million. NHPUC staff made three recommendations: (1) that any further actions relating to PSNH's generating assets await a final decision in the Clean Air Project (scrubber) prudence proceeding; (2) that existing laws regarding divestiture, energy service, and cost recovery be harmonized; and (3) that ISO-NE provide input on the economic and reliability consequences of retirement of PSNH's coal- and oil-fired electric generating plants.

During the 2014 Legislative session, in response to the NHPUC staff report, the Legislature enacted changes to the laws governing divestiture of PSNH's generation assets, effective September 30, 2014. The new law required the NHPUC to initiate a proceeding before January 1, 2015, to determine whether all or some of PSNH's generation assets should be divested. The NHPUC opened its docket DE 14-238 on September 16, 2014. A progress report from the NHPUC must be provided to the Oversight Committee by March 31, 2015. The law gives the NHPUC express authority

to order the divestiture of all or some of PSNH's generation assets if the NHPUC finds it is in the economic interest of customers to do so. The law also clarified the definition of "stranded costs" to include costs approved for recovery by the NHPUC in connection with the divestiture or retirement of PSNH's generation assets.

In the event of generation asset divestiture or retirement, present law and the PSNH Restructuring Settlement Agreement approved in 2000 require that the NHPUC provide recovery of any stranded costs by PSNH. We continue to believe generation investments and prudently-incurred costs remain probable of recovery.

Legislative and Policy Matters

Federal:

On December 19, 2014, the "Tax Increase Prevention Act of 2014" became law, which extended the accelerated deduction of depreciation to businesses through 2014. This extended stimulus provides NU with cash flow benefits of approximately $200 million (approximately $70 million at CL&P) in 2015.

Massachusetts:

On July 7, 2014, Massachusetts enacted "An Act Relative to Natural Gas Leaks" (the Act). The Act establishes a uniform natural gas leak classification standard for all Massachusetts natural gas utilities and a program that accelerates the replacement of aging natural gas infrastructure. The program will enable companies, including NSTAR Gas, to better manage the scheduling and costs of replacement. The Act also calls for the DPU to authorize natural gas utilities to design and offer programs to customers that will increase the availability, affordability and feasibility of natural gas service for new customers. On October 31, 2014, NSTAR Gas filed the GSEP with the DPU. We expect a decision on the program in April 2015.

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires management to make estimates, assumptions and, at times, difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact our financial position, results of operations or cash flows. Our management communicates to and discusses with the Audit Committee of our Board of Trustees significant matters relating to critical accounting policies. Our critical accounting policies are discussed below. See the combined notes to our financial statements for further information concerning the accounting policies, estimates and assumptions used in the preparation of our financial statements.

Regulatory Accounting: The accounting policies of the Regulated companies follow the application of accounting guidance for entities with rate-regulated operations and reflect the effects of the rate-making process.

The application of accounting guidance for rate-regulated enterprises results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. Regulatory assets are amortized as the incurred costs are recovered through customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the applicable regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusion on certain factors, including, but not limited to, regulatory precedent. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred or probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our financial statements. We believe it is probable that the Regulated companies will recover the regulatory assets that have been recorded. If we determined that we could no longer apply the accounting guidance applicable to rate-regulated enterprises to our operations, or that we could not conclude that it is probable that costs would be recovered from customers in future rates, the costs would be charged to earnings in the period in which the determination is made.

Unbilled Revenues: The determination of retail energy sales to residential, commercial and industrial customers is based on the reading of meters, which occurs regularly throughout the month. Billed revenues are based on these meter readings, and the majority of recorded annual revenues is based on actual billings. Because customers are billed throughout the month based on pre-determined cycles rather than on a calendar month basis, an estimate of electricity or natural gas delivered to customers for which the customers have not yet been billed is calculated as of the balance sheet date.

Unbilled revenues represent an estimate of electricity or natural gas delivered to customers but not yet billed. Unbilled revenues are included in Operating Revenues on the statement of income and are assets on the balance sheet that are reclassified to Accounts Receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when there is a change in estimates and under other circumstances.

The Regulated companies estimate unbilled sales monthly using the daily load cycle method. The daily load cycle method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total month load, net of delivery losses, to estimate unbilled sales. Unbilled revenues are estimated by first allocating unbilled sales to the respective customer classes, then applying an estimated rate by customer class to those sales. The estimate of unbilled revenues is sensitive to numerous factors, such as energy demands, weather and changes in the composition of customer classes that can significantly impact the amount of revenues recorded.

Pension and PBOP: We sponsor Pension and PBOP Plans to provide retirement benefits to our employees. Effective January 1, 2015, the two Pension Plans were merged into one Pension Plan, sponsored by NUSCO, and the PBOP Plans were merged into one PBOP Plan, sponsored by NUSCO. For each of these plans, several significant assumptions are used to determine the projected benefit obligation, funded status and net periodic benefit cost. These assumptions include the expected long-term rate of return on plan assets, discount rate, compensation/progression rate, mortality assumptions, and health care cost trend rates. We evaluate these assumptions at least annually and adjust them as necessary. Changes in these assumptions could have a material impact on our financial position, results of operations or cash flows.

Pre-tax net periodic benefit expense (excluding SERP) for the Pension Plans was $118.4 million, $236.3 million and $234.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. The pre-tax net periodic benefit expense for the PBOP Plans was $8.1 million, $32.6 million and $72.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. NSTAR Pension and PBOP expense was included in NU beginning April 10, 2012.

Expected Long-Term Rate of Return on Plan Assets: In developing this assumption, we consider historical and expected returns and input from our consultants. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding expected rates of return for each asset class. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. For the year ended December 31, 2014, our aggregate expected long-term rate of return assumption of 8.25 percent was used to determine our Pension and PBOP expense. For the forecasted 2015 Pension and PBOP expense, our expected long-term rate of return of 8.25 percent for all plans was used reflecting our target asset allocations.

Discount Rate: Payment obligations related to the Pension and PBOP Plans are discounted at interest rates applicable to the expected timing of each plan's cash flows. The discount rate that is utilized in determining the Pension and PBOP obligations is based on a yield-curve approach. This approach is based on a population of bonds with an average rating of AA based on bond ratings by Moody's, S&P and Fitch, and uses bonds with above median yields within that population. As of December 31, 2014, the discount rates used to determine the funded status were 4.2 percent for the Pension Plans and 4.22 percent for the PBOP Plans. As of December 31, 2013, the discount rates used were 5.03 percent for the NUSCO Pension Plan, 4.85 percent for the NSTAR Pension Plan, 4.78 percent for the NUSCO PBOP Plans and 5.10 percent for the NSTAR PBOP Plan. As of December 31, 2014, the decreases in the discount rates resulted in an increase on NU's funded status liability of approximately $530 million and $110 million for the Pension and PBOP Plans, respectively.

Compensation/Progression Rate: This assumption reflects the expected long-term salary growth rate, including consideration of the levels of increases built into collective bargaining agreements, and impacts the estimated benefits that Pension Plan participants receive in the future. As of December 31, 2014, the compensation/progression rate used to determine the funded status was 3.5 percent.

Mortality Assumptions: Assumptions as to mortality of the participants in our Pension and PBOP Plans are a key estimate in measuring the expected payments a participant may receive over their lifetime and the plan liability we need to record. During 2014, the Society of Actuaries released a series of updated mortality tables resulting from recent studies that measured mortality rates for various groups of individuals. The updated mortality tables released in 2014 reflect increased life expectancy of plan participants by 3 to 5 years and have the effect of increasing the estimate of benefits to be provided to plan participants. As of December 31, 2014, the impact of this adoption on NU's funded status was an increase in the liability of approximately $340 million and $82 million for the Pension and PBOP Plans, respectively.

Actuarial Determination of Expense: Pension and PBOP expense is determined by our actuaries and consists of service cost and prior service cost, interest cost based on the discounting of the obligations, amortization of actuarial gains and losses and amortization of the net transition obligation (which was fully amortized in 2013), offset by the expected return on plan assets. Actuarial gains and losses represent differences between assumptions and actual information or updated assumptions.

Effective January 1, 2015, as a result of the merger of the NUSCO Pension and PBOP plans into the respective NSTAR plans, the NSTAR accounting policies became effective for the NUSCO plans. For the NSTAR Pension and PBOP plans, we apply a corridor approach to determine the potential actuarial gain or loss to be amortized in the Pension and PBOP net periodic benefit expense. This amortization approach is applied if the unrecognized actuarial gains or losses exceed 10 percent of the greater of the fair value of plan assets or the projected benefit obligation. This excess is amortized over the average remaining service period of active plan participants. In addition, for the NSTAR plans, the expected return on plan assets is determined by applying the assumed long-term rate of return to the Pension and PBOP Plan asset balances. This calculated expected return is compared to the actual return or loss on plan assets at the end of each year to determine the investment gains or losses to be immediately reflected in actuarial gains and losses. For the years ended December 31, 2014, 2013 and 2012, the NUSCO Pension and PBOP plans did not utilize the corridor approach, and the expected return on plan assets was determined by applying our assumed long-term rate of return to a four-year rolling average of plan asset fair values. This calculation recognized investment gains or losses over a four-year period from the years in which they occurred.

Forecasted Expenses and Expected Contributions: We estimate that the expense for the Pension and PBOP Plans will be approximately $130 million and $4 million, respectively, in 2015. Pension and PBOP expense for subsequent years will depend on future investment performance, changes in future discount rates and other assumptions, and various other factors related to the populations participating in the plans. Pension and PBOP expense charged to earnings is net of the amounts capitalized.

Our policy is to annually fund the Pension Plans in an amount at least equal to the amount that will satisfy federal requirements. We contributed $171.6 million to the Pension Plans in 2014, of which $101 million was contributed by NSTAR Electric. We currently estimate approximately $155 million of contributions to the Pension Plan in 2015.

For the PBOP Plans, it is our policy to annually fund the PBOP Plans up to the maximum tax-deductible level permitted. We contributed $40 million to the PBOP Plans in 2014. We currently estimate approximately $27 million in contributions to the PBOP Plan in 2015.

Sensitivity Analysis: The following represents the hypothetical increase to the Pension Plans' (excluding SERP) and PBOP Plans' reported annual cost as a result of a change in the following assumptions by 50 basis points:

(Millions of Dollars)	Increase in Pension Plan Cost		Increase in PBOP Plan Cost	
	As of December 31,			
Assumption Change	2014	2013	2014	2013
NU				
Lower expected long-term rate of return	$ 19.3	$ 17.2	$ 4.0	$ 3.4
Lower discount rate	$ 19.1	$ 22.3	$ 2.2	$ 6.8
Higher compensation rate	$ 10.2	$ 12.4	N/A	N/A

Health Care Cost: As of December 31, 2014, the health care cost trend rate assumption used to determine the PBOP Plans' year end funded status was 6.5 percent, subsequently decreasing to an ultimate rate of 4.5 percent in 2023. The effect of a hypothetical increase in the health care cost trend rate by one percentage point would be an increase to the service and interest cost components of PBOP Plan expense by $5.3 million in 2014, and a $111.2 million increase to the PBOP obligation.

Goodwill: We have recorded approximately $3.5 billion of goodwill associated with previous mergers and acquisitions. We have identified our reporting units for purposes of allocating and testing goodwill as Electric Distribution, Electric Transmission and Natural Gas Distribution. These reporting units are consistent with our operating segments underlying our reportable segments. Electric Distribution and Electric Transmission reporting units include carrying values for the respective components of CL&P, NSTAR Electric, PSNH and WMECO. The Natural Gas Distribution reporting unit includes the carrying values of NSTAR Gas and Yankee Gas. As of December 31, 2014, goodwill was allocated to the reporting units as follows: $2.5 billion to Electric Distribution, $0.6 billion to Electric Transmission, and $0.4 billion to Natural Gas Distribution.

We are required to test goodwill balances for impairment at least annually by considering the fair values of the reporting units, which requires us to use estimates and judgments. We have selected October 1st of each year as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the carrying value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair values of the reporting units' assets and liabilities is less than the carrying amount of the goodwill. If goodwill were deemed to be impaired, it would be written down in the current period to the extent of the impairment.

We performed an impairment test of goodwill as of October 1, 2014 for the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units. This evaluation required the test of several factors that impact the fair value of the reporting units, including conditions and assumptions that affect the future cash flows of the reporting units. The 2014 goodwill impairment test resulted in a conclusion that goodwill is not impaired and none of the reporting units is at risk of a goodwill impairment.

Income Taxes: Income tax expense is estimated annually for each of the jurisdictions in which we operate. This process involves estimating current and deferred income tax expense or benefit and the impact of temporary differences resulting from differing treatment of items for financial reporting and income tax return reporting purposes. Such differences are the result of timing of the deduction for expenses, as well as any impact of permanent differences, non-tax deductible expenses, or other items, including items that directly impact our tax return as a result of a regulatory activity (flow-through items). The temporary differences and flow-through items result in deferred tax assets and liabilities that are included in the balance sheets. The income tax estimation process impacts all of our segments. We record income tax expense quarterly using an estimated annualized effective tax rate.

We also account for uncertainty in income taxes, which applies to all income tax positions previously filed in a tax return and income tax positions expected to be taken in a future tax return that have been reflected on our balance sheets. The determination of whether a tax position meets the recognition threshold under applicable accounting guidance is based on facts and circumstances available to us. Once a tax position meets the recognition threshold, the tax benefit is measured using a cumulative probability assessment. Assigning probabilities in measuring a recognized tax position and evaluating new information or events in subsequent periods requires significant judgment and could change previous conclusions used to measure the tax position estimate. New information or events may include tax examinations or appeals (including information gained from those examinations), developments in case law, settlements of tax positions, changes in tax law and regulations, rulings by taxing authorities and statute of limitation expirations. Such information or events may have a significant impact on our financial position, results of operations and cash flows.

Accounting for Environmental Reserves: Environmental reserves are accrued when assessments indicate it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to estimates of environmental liabilities could have a significant impact on earnings. We estimate these liabilities based on findings through various phases of the assessment, considering the most likely action plan from a variety of available remediation options (ranging from no action required to full site remediation and long-term monitoring), current site information from our site assessments, remediation estimates from third party engineering and remediation contractors, and our prior experience in remediating contaminated sites. If a most likely action plan cannot yet be determined, we estimate the liability based on the low end of a range of possible action plans. Our estimates incorporate currently enacted state and federal environmental laws and regulations and data released by the EPA and other organizations. The estimates associated with each possible action plan are judgmental in nature partly because there are usually several different remediation options from which to choose. Our estimates are subject to revision in future periods based on actual costs or new information from other sources, including the level of contamination at the site, the extent of our responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

Fair Value Measurements: We follow fair value measurement guidance that defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). We have applied this guidance to our Company's derivative contracts that are not elected or designated as "normal purchases or normal sales" (normal), to marketable securities held in trusts, our valuations of investments in our Pension and PBOP Plans, and nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs.

Changes in fair value of the Regulated company derivative contracts are recorded as Regulatory Assets or Liabilities, as we recover the costs of these contracts in rates charged to customers. These valuations are sensitive to the prices of energy and energy-related products in future years for which markets have not yet developed and assumptions are made.

We use quoted market prices when available to determine fair values of financial instruments. If quoted market prices are not available, fair value is determined using quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments that are not active and model-derived valuations. When quoted prices in active markets for the same or similar instruments are not available, we value derivative contracts using models that incorporate both observable and unobservable inputs. Significant unobservable inputs utilized in the models include energy and energy-related product prices for future years for long-dated derivative contracts and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts, reflecting risk adjusted profit that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect our estimates of nonperformance risk, including credit risk.

Other Matters

Accounting Standards: For information regarding new accounting standards, see Note 1C, "Summary of Significant Accounting Policies - Accounting Standards," to the financial statements.

Contractual Obligations and Commercial Commitments: Information regarding our contractual obligations and commercial commitments as of December 31, 2014 is summarized annually through 2019 and thereafter as follows:

NU *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt maturities [(a)]	$ 216.7	$ 200.0	$ 745.0	$ 810.0	$ 800.0	$ 4,956.6	$ 7,728.3
Estimated interest payments on existing debt [(b)]	336.5	330.7	326.2	273.9	246.2	2,502.3	4,015.8
Capital leases [(c)]	2.4	2.2	2.1	2.1	2.0	3.5	14.3
Operating leases [(d)]	20.1	17.6	14.6	10.5	8.6	22.5	93.9
Funding of pension obligations [(d) (e)]	154.6	146.2	145.4	76.0	15.0	N/A	537.2
Funding of PBOP obligations [(d)]	26.5	27.9	26.3	7.1	4.1	4.5	96.4
Estimated future annual long-term contractual costs [(f)]	685.8	598.2	421.6	327.6	290.0	2,198.4	4,521.6
Total [(g)]	$ 1,442.6	$ 1,322.8	$ 1,681.2	$ 1,507.2	$ 1,365.9	$ 9,687.8	$ 17,007.5

CL&P *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt maturities [(a)]	$ 162.0	$ -	$ 250.0	$ 300.0	$ 250.0	$ 1,640.3	$ 2,602.3
Estimated interest payments on existing debt [(b)]	129.0	126.5	122.5	104.2	88.8	1,138.8	1,709.8
Capital leases [(c)]	2.0	1.9	2.0	2.0	2.0	3.5	13.4
Operating leases [(d)]	4.3	3.8	2.6	1.5	1.1	4.0	17.3
Funding of pension obligations [(d) (e)]	-	0.8	19.7	18.4	4.3	N/A	43.2
Estimated future annual long-term contractual costs [(f)]	233.4	241.8	169.1	123.4	106.4	779.7	1,653.8
Total [(g)]	$ 530.7	$ 374.8	$ 565.9	$ 549.5	$ 452.6	$ 3,566.3	$ 6,039.8

(a) Long-term debt maturities exclude the spent nuclear fuel obligation, net unamortized premiums and discounts, and other fair value adjustments.

(b) Estimated interest payments on fixed-rate debt are calculated by multiplying the coupon rate on the debt by its scheduled notional amount outstanding for the period of measurement. Estimated interest payments on floating-rate debt are calculated by multiplying the end of 2014 floating-rate reset on the debt by its scheduled notional amount outstanding for the period of measurement. This same rate is then assumed for the remaining life of the debt.

(c) The capital lease obligations include interest.

(d) Amounts are not included on our balance sheets.

(e) These amounts represent NU's estimated minimum pension contributions to its qualified Pension Plans required under federal legislation. Contributions in 2016 through 2019 and thereafter will vary depending on many factors, including the performance of existing plan assets, valuation of the plan's liabilities and long-term discount rates, and are subject to change.

(f) Other than certain derivative contracts held by the Regulated companies, these obligations are not included on our balance sheets.

(g) Does not include other long-term liabilities recorded on our balance sheet, such as environmental reserves, employee medical insurance, workers compensation and long-term disability insurance reserves, ARO liability reserves and other reserves, as we cannot make reasonable estimates of the timing of payments. Also does not include an NU contingent commitment not included on our balance sheets of approximately $30 million to an energy investment fund, which would be invested under certain conditions, as we cannot make reasonable estimates of the periods or the investment contributions.

For further information regarding our contractual obligations and commercial commitments, see Note 6, "Asset Retirement Obligations," Note 7, "Short-Term Debt," Note 8, "Long-Term Debt," Note 9A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 11, "Commitments and Contingencies," and Note 12, "Leases," to the financial statements.

RESULTS OF OPERATIONS – NORTHEAST UTILITIES AND SUBSIDIARIES

The following provides the amounts and variances in operating revenues and expense line items in the statements of income for NU for the years ended December 31, 2014, 2013, and 2012 included in this Annual Report on Form 10-K. The year ended December 31, 2012 amounts include the operations of NSTAR beginning April 10, 2012.

Comparison of 2014 to 2013:

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase/ (Decrease)	Percent
Operating Revenues	$ 7,741.9	$ 7,301.2	$ 440.7	6.0 %
Operating Expenses:				
Purchased Power, Fuel and Transmission	3,021.6	2,483.0	538.6	21.7
Operations and Maintenance	1,427.6	1,515.0	(87.4)	(5.8)
Depreciation	614.7	610.8	3.9	0.6
Amortization of Regulatory Assets, Net	10.7	206.3	(195.6)	(94.8)
Amortization of Rate Reduction Bonds	-	42.6	(42.6)	(100.0)
Energy Efficiency Programs	473.1	401.9	71.2	17.7
Taxes Other Than Income Taxes	561.4	512.2	49.2	9.6
Total Operating Expenses	6,109.1	5,771.8	337.3	5.8
Operating Income	1,632.8	1,529.4	103.4	6.8
Interest Expense	362.1	338.7	23.4	6.9
Other Income, Net	24.6	29.9	(5.3)	(17.7)
Income Before Income Tax Expense	1,295.3	1,220.6	74.7	6.1
Income Tax Expense	468.3	426.9	41.4	9.7
Net Income	827.0	793.7	33.3	4.2
Net Income Attributable to Noncontrolling Interests	7.5	7.7	(0.2)	(2.6)
Net Income Attributable to Controlling Interest	$ 819.5	$ 786.0	$ 33.5	4.3 %

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase / (Decrease)	Percent
Electric Distribution	$ 5,663.4	$ 5,362.3	$ 301.1	5.6 %
Natural Gas Distribution	1,007.3	855.8	151.5	17.7
Transmission	1,018.2	978.7	39.5	4.0
Other and Eliminations	53.0	104.4	(51.4)	(49.2)
Total Operating Revenues	$ 7,741.9	$ 7,301.2	$ 440.7	6.0 %

A summary of our retail electric sales volumes and firm natural gas sales volumes were as follows:

	For the Years Ended December 31,			
	2014	2013	Increase/ (Decrease)	Percent
Retail Electric Sales Volumes in GWh	54,442	55,331	(889)	(1.6)%
Firm Natural Gas Sales Volumes in Million Cubic Feet	104,191	98,258	5,933	6.0

Operating Revenues increased $440.7 million in 2014 compared to 2013.

The most significant factor in the increase in revenues relates to cost tracking mechanisms for the recovery of higher costs associated with the procurement of energy supply, which increased $506.8 million and $126.9 million for electric distribution and natural gas distribution, respectively. These costs were impacted by the overall New England wholesale energy supply market in which higher natural gas delivery costs had an adverse impact on the cost of electric energy purchased for our retail electric customers and the cost of natural gas purchased on behalf of our retail natural gas customers. Energy supply costs are recovered from customers in rates through cost tracking mechanisms and therefore have no impact on earnings. These costs and related recovery impacts were partially offset by decreases in transition cost recovery revenues, which are recovered through cost tracking mechanisms, reflecting the full collection in 2013 of previously deferred costs, as well as the full amortization of RRBs.

Firm base natural gas distribution revenues increased $26.3 million in 2014, as compared to 2013, which reflected a 6 percent increase in firm natural gas sales volumes. The increase in sales volumes was driven primarily by the colder winter weather experienced throughout our service territories in the first quarter of 2014. The weather conditions experienced were significantly colder than both normal and the same period last year throughout New England and our service territories in Connecticut and Massachusetts. Weather-normalized total firm natural gas sales volumes (based on 30-year average temperatures) increased 2.9 percent in 2014, as compared to 2013, due primarily to residential and commercial customer growth.

Base electric distribution revenues decreased $12.1 million in 2014 compared to 2013. This reflected the impact of a 1.6 percent decrease in retail electric sales volumes. The decrease in sales volumes was driven primarily by the cooler summer weather in 2014 compared to 2013, as well as the impact of our utility-sponsored energy efficiency programs. Weather-normalized retail electric sales volumes decreased 1 percent in 2014, as compared to 2013, reflecting the impact of our utility-sponsored energy efficiency programs. The negative sales volume impact was partially offset by the impact of CL&P's base distribution rate increase effective December 1, 2014.

CL&P and NSTAR Electric recognized lost base revenue (LBR) related to reductions in sales volume as a result of energy efficiency. LBR is recovered from retail distribution customers. Including the impact from the recognition of LBR, base distribution revenues increased in 2014, as compared to 2013. We recognized $45.2 million of LBR in 2014, compared to $20.3 million in 2013. Effective December 1, 2014, CL&P no longer recognizes LBR due to its revenue decoupling mechanism, which, similar to WMECO's revenue decoupling mechanism, provides a base amount of distribution revenues ($1.041 billion on an annual basis) that effectively breaks the relationship between revenues and customer electricity usage. The revenue decoupling mechanism is designed to allow each of CL&P and WMECO to encourage energy efficiency for its customers without negatively impacting its revenues.

Transmission revenues increased $39.5 million in 2014, as compared to 2013, due primarily to the recovery of higher revenue requirements associated with ongoing investments in our transmission infrastructure. This increase was partially offset by the impact of the $37 million net reserve recorded in 2014 as a result of the 2014 FERC ROE orders, compared to the $23.7 million reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

Purchased Power, Fuel and Transmission expense includes costs associated with purchasing electricity and natural gas on behalf of our customers. These energy supply costs are recovered from customers in rates through reconciling cost tracking mechanisms, which have no impact on earnings (tracked costs). Purchased Power, Fuel and Transmission increased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
Electric Distribution	$	458.2
Natural Gas Distribution		104.1
Transmission		(2.8)
Other and Eliminations		(20.9)
Total Purchased Power, Fuel and Transmission	$	538.6

The increase in purchased power, fuel and transmission at the electric and natural gas distribution businesses were driven by the higher costs associated with the procurement of energy supply. As a result of increases in the New England wholesale energy supply market for both electricity and natural gas, the costs incurred to purchase energy on behalf of our customers were significantly higher in 2014 compared to 2013. Our energy supply costs were impacted by higher natural gas delivery costs, which had an adverse impact on the cost of electric energy purchased for our retail electric customers and the cost of natural gas purchased on behalf of our retail natural gas customers.

Operations and Maintenance expense includes tracked costs and costs that are recovered through base electric and natural gas distribution rates, which therefore impact earnings (non-tracked costs). Operations and Maintenance decreased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
Base Electric Distribution:		
Labor and other employee-related costs, including pension costs	$	(77.3)
Implementation of a new outage restoration program at CL&P		9.2
Storm restoration costs		(11.4)
All other operations and maintenance		(29.4)
Total Base Electric Distribution		(108.9)
Total Base Natural Gas Distribution		(0.9)
Total Tracked costs (Transmission and Electric and Natural Gas Distribution)		16.6
Total Distribution and Transmission		(93.2)
Other and eliminations:		
Integration and severance costs		13.3
All other (including eliminations)		(7.5)
Total Operations and Maintenance	$	(87.4)

Depreciation increased in 2014, as compared to 2013, due primarily to an increase related to higher utility plant balances resulting from completed construction projects placed into service ($34.5 million), partially offset by a decrease in the CYAPC and YAEC decommissioning costs, which do not impact earnings ($30.6 million).

Amortization of Regulatory Assets, Net, which are tracked costs, include certain regulatory-approved tracking mechanisms. Fluctuations in these costs are recovered from customers in rates and have no impact on earnings. Amortization of Regulatory Assets, Net, decreased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
NSTAR Electric (primarily recovery of transition costs)	$	(236.4)
PSNH (primarily default energy service charge)		(9.2)
CL&P (primarily energy supply and energy-related costs)		54.4
WMECO (primarily recovery of transition costs)		(3.0)
Other		(1.4)
Total Amortization of Regulatory Assets, Net	$	(195.6)

Amortization of Rate Reduction Bonds decreased in 2014, as compared to 2013, due to the maturity in 2013 of RRBs of NSTAR Electric, PSNH and WMECO.

Energy Efficiency Programs, which are tracked costs, increased in 2014, as compared to 2013, due primarily to the expanded energy conservation programs at CL&P in 2014 as a result of 2013 legislative action, and an increase in energy efficiency costs in accordance with the three-year program guidelines established by the DPU at NSTAR Electric and WMECO, partially offset by a decrease in the amortization of previously deferred costs at NSTAR Electric.

Taxes Other Than Income Taxes increased in 2014, as compared to 2013, due primarily to an increase in property taxes as a result of both an increase in utility plant balances and property tax rates.

Interest Expense increased in 2014, as compared to 2013, due primarily to lower interest income related to a decrease in the recovery of previously deferred transition costs ($9.9 million), an increase in interest on long-term debt ($4 million) as a result of new debt issuances in 2014 and the absence in 2014 of the favorable impact from the resolution of a Connecticut state income tax audit in 2013.

Other Income, Net decreased in 2014, as compared to 2013, due primarily to lower unrealized gains on the assets supporting the deferred compensation plans ($13 million), and the absence in 2014 of an insurance policy claim received in 2013 ($1.5 million), partially offset by higher AFUDC related to equity funds ($6.6 million), and a net gain on the sale of land ($4.5 million).

Income Tax Expense increased in 2014, as compared to 2013, due primarily to higher pre-tax earnings ($26.1 million), and higher state taxes and various other impacts ($15.3 million). The higher state taxes include a net reduction in the valuation allowance for state tax positions, which is based on the most recent available data.

Comparison of 2013 to 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	2013	2012 (a)	Increase/ (Decrease)	Percent
Operating Revenues	$ 7,301.2	$ 6,273.8	$ 1,027.4	16.4 %
Operating Expenses:				
Purchased Power, Fuel and Transmission	2,483.0	2,084.4	398.6	19.1
Operations and Maintenance	1,515.0	1,583.1	(68.1)	(4.3)
Depreciation	610.8	519.0	91.8	17.7
Amortization of Regulatory Assets, Net	206.3	79.8	126.5	(b)
Amortization of Rate Reduction Bonds	42.6	142.0	(99.4)	(70.0)
Energy Efficiency Programs	401.9	313.1	88.8	28.4
Taxes Other Than Income Taxes	512.2	434.2	78.0	18.0
Total Operating Expenses	5,771.8	5,155.6	616.2	12.0
Operating Income	$ 1,529.4	$ 1,118.2	$ 411.2	36.8 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.
(b) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	2013	2012 (a)	Increase/ (Decrease)	Percent
Electric Distribution	$ 5,362.3	$ 4,716.5	$ 645.8	13.7 %
Natural Gas Distribution	855.8	572.9	282.9	49.4
Total Distribution	6,218.1	5,289.4	928.7	17.6
Transmission	978.7	861.5	117.2	13.6
Total Regulated Companies	7,196.8	6,150.9	1,045.9	17.0
Other and Eliminations	104.4	122.9	(18.5)	(15.1)
Total Operating Revenues	$ 7,301.2	$ 6,273.8	$ 1,027.4	16.4 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.

A summary of our retail electric sales and firm natural gas sales were as follows:

	For the Years Ended December 31,			
	2013	2012 (a)	Increase	Percent
Retail Electric Sales in GWh	55,331	54,808	523	1.0 %
Firm Natural Gas Sales in Million Cubic Feet	98,258	87,527	10,731	12.3

(a) Results include retail electric sales of NSTAR Electric and the firm natural gas sales of NSTAR Gas from January 1, 2012 through December 31, 2012 for comparative purposes only.

Our Operating Revenues increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations. During the first quarter of 2013, the former operating subsidiaries of NSTAR contributed approximately $800 million of operating revenues. Absent the first quarter 2013 NSTAR operating revenues, our Operating Revenues increased approximately $227 million, as compared to 2012, due primarily to:

- A $62.5 million increase in transmission revenues, net of applicable eliminations, as a result of the recovery of higher transmission expenses and continuing investments in our transmission infrastructure. The increase was partially offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.
- A $34.3 million increase in base electric distribution revenues, net of applicable eliminations, reflecting an increase of approximately 1 percent in retail electric sales. The increase in sales volumes was driven primarily by the colder winter weather experienced throughout our service territories in early and late 2013. In addition, the increase in revenues resulted from the NHPUC-approved distribution rate increases at PSNH effective July 1, 2012 and July 1, 2013 as a result of the 2010 distribution rate case settlement. These positive impacts on revenue were partially offset by the impact of our utility-sponsored energy efficiency programs.
- A $28.8 million increase in firm natural gas distribution revenues. This increase was driven by the colder winter weather in early and late 2013, residential customer growth, an increase in natural gas conversions, the migration of interruptible customers switching to firm service rates and the addition of gas-fired distributed generation.
- The remaining increase was due primarily to higher revenues from increases related to our fully reconciling cost recovery mechanisms (tracked costs) related to the recovery of energy supply, retail transmission and utility-sponsored energy efficiency programs. Revenues related to cost recovery mechanisms vary from period to period based on the timing of collections of the costs incurred. These revenues do not result in an impact on earnings.

Purchased Power, Fuel and Transmission increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
The addition of NSTAR's operations	$	321.4
Transmission segment costs		70.8
Firm natural gas sales related costs		42.0
Partially offset by:		
Electric distribution segment fuel and energy supply costs		(13.9)
CfDs and capacity contracts		(12.0)
All other items		(9.7)
	$	398.6

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
The addition of NSTAR's operations	$	123.6
Partially offset by:		
Integration, merger and settlement agreement costs		(150.3)
NU's unregulated contracting business costs		(17.4)
General and administrative costs		(12.9)
Transmission segment costs		(5.2)
Natural gas segment costs		10.5
Electric distribution segment costs		1.3
All other items		(17.7)
	$	(68.1)

Depreciation increased in 2013, as compared to 2012, due primarily to the addition of NSTAR ($54.2 million) and the consolidation of CYAPC and YAEC ($13.7 million). Excluding the impact of NSTAR and the consolidation of CYAPC and YAEC, depreciation increased due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)		Increase/(Decrease)
The addition of NSTAR's operations	$	45.8
Recovery of transition costs at NSTAR Electric		91.9
Amortization related to CL&P's SBC and CTA		(6.8)
Other		(4.4)
	$	126.5

Amortization of Rate Reduction Bonds decreased in 2013, as compared to 2012, due primarily to the maturity of NSTAR Electric's, PSNH's, and WMECO's RRBs in 2013, partially offset by the addition of NSTAR Electric's amortization ($15.1 million).

Energy Efficiency Programs increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations ($68.6 million), as well as an increase in energy efficiency costs in accordance with the three-year program guidelines established by the DPU at NSTAR Electric and WMECO. All costs are fully recovered through DPU-approved tracking mechanisms and therefore do not impact earnings.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations ($37.8 million). In addition, there was an increase in property taxes ($36.6 million) as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates, and an increase in the Connecticut gross earnings tax ($9.1 million) attributable to an increase in gross earnings.

Interest Expense increased $8.8 million in 2013, as compared to 2012, due primarily to the addition of NSTAR's operations ($22 million) and lower interest income on deferred transition costs ($10.6 million), partially offset by a decrease in Other Interest due primarily to the favorable impact from the resolution of a state income tax audit in the first quarter of 2013, lower interest on short-term debt ($8.8 million) and lower interest on RRBs ($6.1 million).

Other Income, Net increased $10.2 million in 2013, as compared to 2012, due primarily to higher gains on the NU supplemental benefit trust ($6 million) and an increase related to officer insurance policies ($1.7 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2013	2012 [(a)]	Increase	Percent
Income Tax Expense	$ 426.9	$ 274.9	$ 152.0	55.3 %

(a) The 2012 results include the operations of NSTAR beginning April 10, 2012.

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($81 million), the absence in 2013 of both prior year Connecticut and Massachusetts merger settlement agreement impacts ($41 million) and integration merger impacts ($23 million), along with various other items ($7 million).

RESULTS OF OPERATIONS – THE CONNECTICUT LIGHT AND POWER COMPANY

The following provides the amounts and variances in operating revenues and expense line items in the statements of income for CL&P for the years ended December 31, 2014, 2013, and 2012 included in this Annual Report on Form 10-K:

Comparison of 2014 to 2013:

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase/ (Decrease)	Percent
Operating Revenues	$ 2,692.6	$ 2,442.3	$ 250.3	10.2 %
Operating Expenses:				
Purchased Power and Transmission	982.9	872.8	110.1	12.6
Operations and Maintenance	494.6	523.2	(28.6)	(5.5)
Depreciation	188.8	177.6	11.2	6.3
Amortization of Regulatory Assets, Net	59.3	4.9	54.4	(a)
Energy Efficiency Programs	156.3	89.8	66.5	74.1
Taxes Other Than Income Taxes	255.4	234.4	21.0	9.0
Total Operating Expenses	2,137.3	1,902.7	234.6	12.3
Operating Income	555.3	539.6	15.7	2.9
Interest Expense	147.4	133.6	13.8	10.3
Other Income, Net	13.4	15.1	(1.7)	(11.3)
Income Before Income Tax Expense	421.3	421.1	0.2	-
Income Tax Expense	133.5	141.7	(8.2)	(5.8)
Net Income	$ 287.8	$ 279.4	$ 8.4	3.0 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues
CL&P's retail sales volumes were as follows:

	For the Years Ended December 31,			
	2014	2013	Decrease	Percent
Retail Sales Volumes in GWh	22,046	22,404	(358)	(1.6)%

CL&P's Operating Revenues increased $250.3 million in 2014 compared to 2013. The increase primarily reflects recovery of higher costs associated with the procurement of energy supply, which increased $275.4 million, and increased cost recovery related to our energy efficiency programs. The energy supply costs were impacted by the overall wholesale electricity market in New England in which higher natural gas delivery costs had an adverse impact on the cost of electric energy purchased for our retail customers. Energy supply costs are recovered from customers in rates through cost tracking mechanisms and therefore have no impact on earnings.

Partially offsetting this increase was the impact of the $20.7 million net reserve recorded in 2014 as a result of the 2014 FERC ROE orders, as compared to the $12.8 million reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

Base distribution revenues increased $9.1 million in 2014 compared to 2013, which was primarily attributable to the impact of the December 1, 2014 base distribution rate increase and the impact of LBR, partially offset by the impact of cooler summer weather as well as energy efficiency programs. Enhancements to CL&P's energy efficiency programs were mandated by the Connecticut legislature in 2013. Through November 30, 2014, CL&P was permitted to bill customers for LBR related to reductions in sales volume as a result of energy efficiency and effective December 1, 2014, fluctuations in retail electric sales volumes do not impact earnings due to the PURA-approved revenue decoupling mechanism as a result of CL&P's base distribution rate case. The revenue decoupling mechanism provides a base amount of distribution revenues ($1.041 billion on an annual basis) that effectively breaks the relationship between revenues and customer electricity usage. The revenue decoupling mechanism is designed to allow CL&P to encourage energy efficiency for its customers without negatively impacting its revenues.

Purchased Power and Transmission expense includes costs associated with purchasing electricity on behalf of CL&P's customers. These energy supply costs are recovered from customers in PURA-approved cost tracking mechanisms, which have no impact on earnings (tracked costs). Purchased Power and Transmission increased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)	Increase/(Decrease)
Purchased Power Costs	$ 169.7
Transmission Costs	(50.8)
Other	(8.8)
Total Purchased Power and Transmission	$ 110.1

Included in purchased power are the costs associated with CL&P's generation services charge (GSC) and deferred energy supply costs. The GSC recovers energy-related costs incurred as a result of providing electric generation service supply to all customers that have not migrated to third party suppliers. The increase in purchased power was due primarily to higher average supply prices and increased standard offer load as a result of customers returning from third party suppliers. The decrease in transmission costs was the result of a decrease in the retail transmission cost deferral, which reflects the actual costs of transmission service compared to estimated amounts billed to customers.

Operations and Maintenance expense includes tracked costs and costs that are part of base distribution rates with changes impacting earnings (non-tracked costs). Operations and Maintenance decreased in 2014, as compared to 2013, driven by a $38.4 million reduction in non-tracked costs, which was primarily attributable to lower labor and other employee-related costs, including pension costs, and lower storm restoration costs, partially offset

by an increase in costs for the implementation of a new outage restoration program that began in the second quarter of 2014. Partially offsetting this decrease was a $9.8 million increase in tracked costs, which have no earnings impact, that was primarily attributable to higher tracked bad debt expense and increased transmission maintenance expenses.

Depreciation increased in 2014, as compared to 2013, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net, increased in 2014, as compared to 2013. Fluctuations in energy supply and energy-related costs, which are the primary drivers in amortization, are recovered from customers in rates through cost tracking mechanisms and have no impact on earnings.

Energy Efficiency Programs, which are tracked costs, increased in 2014, as compared to 2013, due primarily to expanded energy conservation programs in 2014 as a result of 2013 legislative action. In 2013, Connecticut enacted into law Public Act 13-298, which implemented a number of recommendations, including allowing electric distribution companies to recover their costs as well as LBR from various state energy policy initiatives and expanded energy efficiency programs.

Taxes Other Than Income Taxes increased in 2014, as compared to 2013, due primarily to an increase in property taxes as a result of both an increase in utility plant balances and property tax rates.

Interest Expense increased in 2014, as compared to 2013, due primarily to an increase in interest on long-term debt ($5 million) as a result of a new debt issuance in April 2014 and an increase in regulatory interest due to the refund of the DOE proceeds in 2014 and the absence in 2014 of the favorable impact from the resolution of a state income tax audit in 2013.

Other Income, Net decreased in 2014, as compared to 2013, due primarily to lower unrealized gains on the assets supporting the deferred compensation plans ($6.7 million), partially offset by a gain on the sale of land ($4.5 million).

Income Tax Expense decreased in 2014, as compared to 2013, due primarily to lower state taxes, which includes the reduction in the valuation allowance for state tax positions, and various other impacts.

EARNINGS SUMMARY

CL&P's earnings increased in 2014, as compared to 2013, due primarily to a decrease in operations and maintenance costs primarily attributable to lower employee-related costs, as well as lower income tax expense due to the net reduction in the valuation allowance for state tax positions. Partially offsetting these favorable earnings impacts were lower retail electric sales volumes, higher depreciation expense, higher property tax expense, higher interest expense and the after-tax reserve recorded for the 2014 FERC ROE orders as compared to the reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

Comparison of 2013 to 2012:

	Operating Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	2013	2012	Increase/ (Decrease)	Percent
Operating Revenues	$ 2,442.3	$ 2,407.4	$ 34.9	1.4 %
Operating Expenses:				
Purchased Power and Transmission	872.8	858.2	14.6	1.7
Operations and Maintenance	523.2	635.7	(112.5)	(17.7)
Depreciation	177.6	166.9	10.7	6.4
Amortization of Regulatory Assets, Net	4.9	14.4	(9.5)	(66.0)
Energy Efficiency Programs	89.8	89.3	0.5	0.6
Taxes Other Than Income Taxes	234.4	215.9	18.5	8.6
Total Operating Expenses	1,902.7	1,980.4	(77.7)	(3.9)
Operating Income	$ 539.6	$ 427.0	$ 112.6	26.4 %

Operating Revenues

CL&P's retail sales were as follows:

	For the Years Ended December 31,			
	2013	2012	Increase	Percent
Retail Sales in GWh	22,404	22,109	295	1.3 %

CL&P's Operating Revenues increased in 2013, as compared to 2012, due primarily to:

- A $15.8 million increase in transmission revenues reflecting recovery of higher transmission expenses and continuing transmission infrastructure investments. The increase was partially offset by the establishment of a reserve related to the FERC ALJ initial decision in the third quarter of 2013.
- A $13.5 million increase in base distribution revenues reflecting a 1.3 percent increase in retail sales. This increase was due primarily to the colder winter weather experienced in early and late 2013.
- The remaining $5.6 million increase was due primarily to higher collections of costs through reconciling cost tracking mechanisms. These revenues are fully reconciled to the related costs. Therefore this increase in revenues had no impact on earnings.

Purchased Power and Transmission increased in 2013, as compared to 2012, due primarily to the following:

(Millions of Dollars)	Increase/(Decrease)
Transmission Costs	$ 45.8
Deferred Fuel Costs	28.7
GSC Supply Costs	(44.2)
Purchased Power Contracts	(12.1)
CfD Costs	(7.3)
Other	3.7
	$ 14.6

The increase in transmission costs was the result of an increase in the retail transmission deferral, which related rates are adjusted on an annual basis as a result of collecting or refunding costs of the transmission systems to customers. The decrease in GSC supply costs was due primarily to lower average supply prices. On July 1, 2013, CL&P began to procure approximately thirty percent of GSC load. Costs associated with the remaining seventy percent of the GSC load are the contractual amounts CL&P must pay to various suppliers that have been awarded the right to supply SS and LRS load through a competitive solicitation process. Purchased Power and Transmission costs are included in regulatory-approved tracking mechanisms and do not impact earnings.

Operations and Maintenance decreased in 2013, as compared to 2012, due primarily to the absence in 2013 of costs recognized in the second quarter of 2012 as a result of the Connecticut merger settlement agreement (which established a $40 million storm fund reserve and provided a $25 million bill credit to customers). In addition, there were lower distribution operating costs ($10.2 million), the absence in 2013 of amortization of the PBOP transition obligation ($6.1 million), lower distribution general and administrative costs ($7.5 million) and lower distribution costs related to customer Energy Independence Act incentives ($6.3 million). These lower costs were partially offset by an increase in distribution routine maintenance and storm-related costs ($7.4 million).

Depreciation increased in 2013, as compared to 2012, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net decreased in 2013, as compared to 2012, due primarily to a lower net SBC deferral, partially offset by a higher net CTA deferral. SBC revenues were $23 million lower in 2013, as compared to 2012, partially offset by higher hardship program costs of $6.6 million in 2013. CTA revenues were $13.9 million higher in 2013, as compared to 2012, and costs were $30.5 million lower in 2013, as compared to 2012. DOE refunds of $21.6 million were returned to customers in the second half of 2013. All of these items represent reconciliations of previously incurred costs and have a corresponding revenue offset, so there is no earnings impact.

Taxes Other Than Income Taxes increased in 2013, as compared to 2012, due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment and an increase in the property tax rates ($11.5 million). In addition, there was an increase in the Connecticut gross earnings tax attributable to an increase in gross earnings ($7.6 million).

Interest Expense increased $0.5 million in 2013, as compared to 2012, due primarily to higher interest on long-term debt ($5.7 million), partially offset by a decrease in other interest as a result of a favorable impact from the resolution of a state income tax audit in the first quarter of 2013 ($5.4 million).

Other Income increased $4.8 million in 2013, as compared to 2012, due primarily to higher gains on the NU supplemental benefit trust.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	2013	2012	Increase	Percent
Income Tax Expense	$ 141.7	$ 94.4	$ 47.3	50.1 %

Income Tax Expense increased in 2013, as compared to 2012, due primarily to higher pre-tax earnings ($17.1 million), the absence in 2013 of the impact of costs recognized as a result of the Connecticut merger settlement agreement ($26.6 million), and higher state taxes ($5.7 million), partially offset by various other items ($2.1 million).

LIQUIDITY

In 2014, CL&P had cash flows provided by operating activities of $612.4 million, compared with $495.3 million in 2013. The improved operating cash flows were due primarily to $68.6 million in DOE damages proceeds received in 2014 from the Yankee Companies associated with the spent nuclear fuel litigation, the absence of cash disbursements for major storm restoration costs, and the favorable cash flow impact resulting from an increase in recoveries from customers in 2014, as compared to 2013, relating to regulatory cost recovery tracking mechanisms, partially offset by higher income tax payments in 2014, as compared to 2013, and changes in working capital items.

In 2013, CL&P had cash flows provided by operating activities of $495.3 million, compared with $211.9 million in 2012. The improved cash flows were due primarily to a decrease of approximately $75 million in cash disbursements for storm restoration costs associated primarily with Tropical Storm Irene and the October 2011 snowstorm, the absence of approximately $27 million in 2012 CL&P customer bill credits associated with the October 2011 snowstorm and the absence of $25 million in 2012 CL&P customer bill credits associated with the Connecticut settlement agreement. In addition, operating cash flows benefited from an increase in regulatory overrecoveries where such revenues exceeded costs resulting in a favorable cash flow impact, higher net income and timing of payables. Partially offsetting improved cash flows were income tax payments of $55 million in 2013, compared with income tax refunds of $42 million in 2012.

Investments in Property, Plant and Equipment on the statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension expense. CL&P's investments totaled $515.7 million in 2014, compared with $434.9 million in 2013.

Effective July 23, 2014, NU parent and certain of its subsidiaries, including CL&P, extended the expiration date of their joint $1.45 billion revolving credit facility for one additional year to September 6, 2019. The revolving credit facility is to be used primarily to backstop NU parent's $1.45 billion commercial paper program. The commercial paper program allows NU parent to issue commercial paper as a form of short-term debt with intercompany loans to certain subsidiaries, including CL&P. As of December 31, 2014 and 2013, there were intercompany loans from NU parent of $133.4 million and $287.3 million, respectively, to CL&P.

On April 24, 2014, CL&P issued $250 million of 4.30 percent 2014 Series A First Mortgage Bonds, due to mature in 2044. The proceeds, net of issuance costs, were used to repay short-term borrowings.

On September 15, 2014, CL&P repaid at maturity the $150 million of 4.80 percent 2004 Series A First Mortgage Bonds.

On August 27, 2014, PURA approved CL&P's request to extend the authorization period for issuance of up to $366.4 million in long-term debt from December 31, 2014 to December 31, 2015.

Financing activities in 2014 included $171.2 million in common stock dividends paid to NU parent.

RESULTS OF OPERATIONS – NSTAR ELECTRIC COMPANY AND SUBSIDIARY

The following provides the amounts and variances in operating revenues and expense line items in the statements of income for NSTAR Electric for the years ended December 31, 2014 and 2013 included in this Annual Report on Form 10-K:

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase/ (Decrease)	Percent
Operating Revenues	$ 2,536.7	$ 2,493.5	$ 43.2	1.7 %
Operating Expenses:				
Purchased Power and Transmission	1,122.3	849.1	273.2	32.2
Operations and Maintenance	327.0	376.4	(49.4)	(13.1)
Depreciation	188.7	180.3	8.4	4.7
Amortization of Regulatory Assets/(Liabilities), Net	(6.3)	230.1	(236.4)	(a)
Amortization of Rate Reduction Bonds	-	15.1	(15.1)	(100.0)
Energy Efficiency Programs	193.5	206.5	(13.0)	(6.3)
Taxes Other Than Income Taxes	133.0	127.8	5.2	4.1
Total Operating Expenses	1,958.2	1,985.3	(27.1)	(1.4)
Operating Income	578.5	508.2	70.3	13.8
Interest Expense	77.9	70.4	7.5	10.7
Other Income, Net	4.5	3.6	0.9	25.0
Income Before Income Tax Expense	505.1	441.4	63.7	14.4
Income Tax Expense	202.0	172.9	29.1	16.8
Net Income	$ 303.1	$ 268.5	$ 34.6	12.9 %

(a) Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues
NSTAR Electric's retail sales volumes were as follows:

	For the Years Ended December 31,			
	2014	2013	Decrease	Percent
Retail Sales Volumes in GWh	20,925	21,306	(381)	(1.8)%

NSTAR Electric's Operating Revenues increased $43.2 million in 2014 compared to 2013. The increase primarily reflects recovery of higher costs associated with the procurement of energy supply, which increased $195.5 million. The energy supply costs were impacted by the overall wholesale electricity market in New England in which higher natural gas delivery costs had an adverse impact on the cost of electric energy purchased for our retail customers. Energy supply costs are recovered from customers in rates through cost tracking mechanisms and therefore have no impact on earnings. These costs and related recovery impacts were partially offset by decreases in transition cost recovery revenues, which are recovered through cost tracking mechanisms, reflecting the full collection in 2013 of previously deferred costs, as well as the full amortization of RRBs.

Base distribution revenues decreased in 2014, as compared to 2013, due primarily to cooler summer weather and an increase in customer conservation efforts due to the impact of energy efficiency programs. NSTAR Electric recovers LBR related to reductions in sales volume as a result of energy efficiency. In 2014, including the impact from the recognition of LBR, base distribution revenues increased in 2014, compared to 2013, by $3.7 million.

Transmission revenues increased $21.7 million in 2014, as compared to 2013, due primarily to the recovery of higher revenue requirements associated with ongoing investments in our transmission infrastructure. This increase was partially offset by the impact of the $7.9 million net reserve recorded in 2014 as a result of the 2014 FERC ROE orders, compared to the $5.7 million reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

Purchased Power and Transmission expense includes costs associated with purchasing electricity on behalf of NSTAR Electric's customers. These energy supply costs are recovered from customers in DPU-approved cost tracking mechanisms, which have no impact on earnings (tracked costs). Purchased Power and Transmission increased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)	Increase
Purchased Power Costs	$ 202.9
Transmission Costs	64.6
Other	5.7
Total Purchased Power and Transmission	$ 273.2

Included in purchased power are the costs associated with NSTAR Electric's basic service charge and deferred energy supply costs. The basic service charge recovers energy-related costs incurred as a result of providing electric generation service supply to all customers that have not migrated to third party suppliers. The increase in purchased power was due primarily to higher average energy supply prices. The increase in transmission costs was due primarily to higher regional transmission expense.

Operations and Maintenance expense includes tracked costs and costs that are part of base distribution rates with changes impacting earnings (non-tracked costs). Operations and Maintenance decreased in 2014, as compared to 2013, driven by a $57.4 million reduction in non-tracked costs, which was primarily attributable to lower labor and other employee-related costs and lower storm restoration costs. Partially offsetting this decrease was an $8 million increase in tracked costs, which have no earnings impact, that was primarily attributable to an increased level of recovery of deferred storm costs and increased transmission maintenance expenses.

Depreciation increased in 2014, as compared to 2013, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets/(Liabilities), Net, decreased due primarily to the absence in 2014 of the recovery of tracked transition costs, reflecting the full collection in 2013 of these previously deferred costs. Fluctuations in these costs are recovered from customers in rates through cost tracking mechanisms and have no impact on earnings.

Amortization of Rate Reduction Bonds decreased in 2014, as compared to 2013, due to the maturity of the RRBs in March 2013.

Energy Efficiency Programs, which are tracked costs, decreased in 2014, as compared to 2013, due primarily to a decrease in the amortization of previously deferred costs. This was partially offset by an increase in energy efficiency costs incurred in accordance with the three-year program guidelines established by the DPU.

Taxes Other Than Income Taxes increased in 2014, as compared to 2013, due primarily to an increase in property taxes as a result of both an increase in utility plant balances and property tax rates.

Interest Expense increased in 2014, as compared to 2013, due primarily to lower interest income from a decrease in the recovery of previously deferred tracked transition costs ($9.9 million), partially offset by a decrease in interest on long-term debt ($2 million).

Income Tax Expense increased in 2014, as compared to 2013, due primarily to higher pre-tax earnings ($22.4 million), and higher state taxes ($6.7 million).

EARNINGS SUMMARY

NSTAR Electric's earnings increased in 2014, as compared to 2013, due primarily to lower operations and maintenance costs primarily attributable to lower employee-related costs and higher transmission earnings, partially offset by higher interest expense, higher depreciation expense, higher property tax expense and the after-tax reserve recorded for the 2014 FERC ROE orders as compared to the reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

LIQUIDITY

NSTAR Electric had cash flows provided by operating activities of $533 million in 2014, compared with $510.4 million in 2013. The improved operating cash flows were due primarily to the absence of cash disbursements for major storm restoration costs associated with the February 2013 blizzard, collections of accounts receivable from affiliated companies, and $30.2 million in DOE damages proceeds in 2014 from the Yankee Companies associated with the spent nuclear fuel litigation. These favorable cash flow impacts were partially offset by a $38.3 million increase in Pension and PBOP Plan cash contributions in 2014 compared to 2013, the unfavorable cash flow impact resulting from the absence in 2014 of the recovery of previously deferred tracked transition costs that were fully collected in 2013, the absence of costs recovered in rates related to the RRBs that were fully amortized in 2013, and an increase in income taxes paid.

NSTAR Electric has a five-year $450 million revolving credit facility. This facility serves to backstop NSTAR Electric's existing $450 million commercial paper program. Effective July 23, 2014, NSTAR Electric extended the expiration date of its revolving credit facility for one additional year to September 6, 2019. As of December 31, 2014 and 2013, NSTAR Electric had $302 million and $103.5 million, respectively, in short-term borrowings outstanding under its commercial paper program, leaving $148 million and $346.5 million of available borrowing capacity as of December 31, 2014 and 2013, respectively. The weighted-average interest rate on these borrowings as of December 31, 2014 and 2013 was 0.27 percent and 0.13 percent, respectively, which is generally based on A2/P1 rated commercial paper.

RESULTS OF OPERATIONS – PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

The following provides the amounts and variances in operating revenues and expense line items in the statements of income for PSNH for the years ended December 31, 2014 and 2013 included in this Annual Report on Form 10-K:

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase/ (Decrease)	Percent
Operating Revenues	$ 959.5	$ 935.4	$ 24.1	2.6 %
Operating Expenses:				
Purchased Power, Fuel and Transmission	313.7	269.8	43.9	16.3
Operations and Maintenance	261.9	267.8	(5.9)	(2.2)
Depreciation	98.4	91.6	6.8	7.4
Amortization of Regulatory Liabilities, Net	(29.6)	(20.4)	(9.2)	45.1
Amortization of Rate Reduction Bonds	-	19.7	(19.7)	(100.0)
Energy Efficiency Programs	14.3	14.5	(0.2)	(1.4)
Taxes Other Than Income Taxes	71.4	67.2	4.2	6.3
Total Operating Expenses	730.1	710.2	19.9	2.8
Operating Income	229.4	225.2	4.2	1.9
Interest Expense	45.4	46.2	(0.8)	(1.7)
Other Income, Net	2.0	3.5	(1.5)	(42.9)
Income Before Income Tax Expense	186.0	182.5	3.5	1.9
Income Tax Expense	72.1	71.1	1.0	1.4
Net Income	$ 113.9	$ 111.4	$ 2.5	2.2 %

Operating Revenues
PSNH's retail sales volumes were as follows:

	For the Years Ended December 31,			
	2014	2013	Decrease	Percent
Retail Sales Volumes in GWh	7,886	7,938	(52)	(0.7)%

PSNH's Operating Revenues increased $24.1 million in 2014 compared to 2013. The increase primarily reflects the recovery of higher costs associated with the procurement of energy supply and the generation of electricity for our customers, which increased $19.8 million. The energy supply costs were impacted by higher natural gas delivery costs, which had an adverse impact on the cost of electric energy purchased for our retail customers. Also reflected in the revenue increase were increases of $6.3 million related to NHPUC-approved distribution rate increases effective July 1, 2013 and increases in transmission revenues as a result of the recovery of higher transmission expenses including ongoing investments in our transmission infrastructure. These increases were partially offset by a decrease in stranded cost recovery revenues, which are recovered through cost tracking mechanisms, due to the refund to customers of DOE damages proceeds received from the Yankee Companies resulting from the spent nuclear fuel litigation.

Purchased Power, Fuel and Transmission expense includes costs associated with PSNH's generation of electricity as well as purchasing electricity on behalf of its customers. These energy supply costs are recovered from customers in NHPUC-approved cost tracking mechanisms, which have no impact on earnings (tracked costs). Purchased Power, Fuel and Transmission increased in 2014, as compared to 2013, due primarily to the following

(Millions of Dollars)	Increase/(Decrease)
Generation Fuel Costs	$ 41.6
Transmission Costs	13.2
Purchased Power Costs	(9.4)
Other	(1.5)
Total Purchased Power, Fuel and Transmission	$ 43.9

The increase in generation fuel costs was due primarily to an increase in the amount of electricity generated by PSNH facilities in 2014, as compared to 2013. Included in purchased power are the costs associated with the PSNH energy service charge. The decrease in purchased power costs was a result of purchasing less power from third party suppliers due to increased PSNH generation. The increase in transmission costs was the result of an increase in the retail transmission cost deferral, which reflects the actual costs of transmission service compared to estimated amounts billed to customers.

Operations and Maintenance expense includes tracked costs and costs that are part of base distribution rates with changes impacting earnings (non-tracked costs). Operations and Maintenance decreased in 2014, as compared to 2013, driven by an $8.3 million reduction in non-tracked costs, which was primarily attributable to lower labor and other employee-related costs, including pension costs, and lower storm restoration costs. Partially offsetting this decrease was a $2.4 million increase in tracked costs, which have no earnings impact, that was primarily attributable to increased maintenance activities at PSNH's generating facilities.

Depreciation increased in 2014, as compared to 2013, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Liabilities, Net, reflects a decrease in the recovery of the default energy service charge and other amortizations in 2014, as compared to 2013. Fluctuations in these costs are recovered from customers in rates through cost tracking mechanisms and have no impact on earnings.

Amortization of Rate Reduction Bonds decreased in 2014, as compared to 2013, due to the maturity of the RRBs in May 2013.

Taxes Other Than Income Taxes increased in 2014, as compared to 2013, due primarily to an increase in property taxes as a result of both an increase in utility plant balances and property tax rates.

Other Income, Net decreased in 2014, as compared to 2013, due primarily to lower unrealized gains on the assets supporting the deferred compensation plans ($1.8 million).

Income Tax Expense increased in 2014, as compared to 2013, due primarily to higher pre-tax earnings.

EARNINGS SUMMARY

PSNH's earnings increased in 2014, as compared to 2013, due primarily to higher transmission earnings, a decrease in operations and maintenance costs primarily attributable to lower employee-related costs, and higher distribution retail revenues, which were favorably impacted by the PSNH annualized distribution rate increases effective July 1, 2013. Partially offsetting this favorable earnings impact was higher depreciation expense.

LIQUIDITY

PSNH had cash flows provided by operating activities of $248 million in 2014, compared with $188.1 million in 2013. The improved operating cash flows were due primarily to the absence of $108.3 million in Pension Plan cash contributions made in 2013, $14.5 million in DOE damages proceeds received in 2014 from the Yankee Companies associated with the spent nuclear fuel litigation, and the favorable impact of the NHPUC-approved distribution rate increases that were effective July 1, 2013. These favorable cash flow impacts were partially offset by higher income tax payments in 2014, as compared to 2013, and the absence of costs recovered in rates related to the RRBs that were fully amortized in 2013.

RESULTS OF OPERATIONS – WESTERN MASSACHUSETTS ELECTRIC COMPANY

The following provides the amounts and variances in operating revenues and expense line items in the statements of income for WMECO for the years ended December 31, 2014 and 2013 included in this Annual Report on Form 10-K:

	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	Increase/ (Decrease)	Percent
Operating Revenues	$ 493.4	$ 472.7	$ 20.7	4.4 %
Operating Expenses:				
Purchased Power and Transmission	172.9	147.1	25.8	17.5
Operations and Maintenance	89.4	96.2	(6.8)	(7.1)
Depreciation	41.9	37.6	4.3	11.4
Amortization of Regulatory Assets/(Liabilities), Net	(6.2)	(3.2)	(3.0)	93.8
Amortization of Rate Reduction Bonds	-	7.8	(7.8)	(100.0)
Energy Efficiency Programs	42.9	39.5	3.4	8.6
Taxes Other Than Income Taxes	34.9	28.4	6.5	22.9
Total Operating Expenses	375.8	353.4	22.4	6.3
Operating Income	117.6	119.3	(1.7)	(1.4)
Interest Expense	24.9	24.8	0.1	0.4
Other Income, Net	2.4	3.3	(0.9)	(27.3)
Income Before Income Tax Expense	95.1	97.8	(2.7)	(2.8)
Income Tax Expense	37.3	37.4	(0.1)	(0.3)
Net Income	$ 57.8	$ 60.4	$ (2.6)	(4.3)%

Operating Revenues
WMECO's retail sales volumes were as follows:

	For the Years Ended December 31,			
	2014	2013	Decrease	Percent
Retail Sales Volumes in GWh	3,586	3,683	(97)	(2.6)%

WMECO's Operating Revenues increased $20.7 million in 2014 compared to 2013. The increase primarily reflects recovery of higher costs associated with the procurement of energy supply, which increased $15.2 million. The energy supply costs were impacted by the overall wholesale electricity market in New England in which higher natural gas delivery costs had an adverse impact on the cost of electric energy purchased for our retail customers. Energy supply costs are recovered from customers in rates through cost tracking mechanisms and therefore have no impact on earnings.

Transition cost recovery revenues, which are recovered through cost tracking mechanisms, decreased due to the refund to customers of DOE damages proceeds received from the Yankee Companies resulting from the spent nuclear fuel litigation.

Fluctuations in WMECO's kWh sales have no impact on earnings, as its revenues are decoupled from sales volumes and changes in revenues are primarily related to changes in its cost tracking mechanisms.

Transmission revenues increased in 2014 compared to 2013 due primarily to the recovery of higher revenue requirements associated with ongoing investments in our transmission infrastructure. There was also a $3.9 million increase in revenues that impacts earnings due to the reversal in 2014 of a previously established wholesale billing adjustment. Partially offsetting the increase was the impact of the $5.6 million net reserve recorded in 2014 as a result of the 2014 FERC ROE orders, as compared to the $2.9 million reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints.

Purchased Power and Transmission expense includes costs associated with purchasing electricity on behalf of WMECO's customers. These energy supply costs are recovered from customers in DPU-approved cost tracking mechanisms, which have no impact on earnings (tracked costs). Purchased Power and Transmission increased in 2014, as compared to 2013, due primarily to the following:

(Millions of Dollars)	Increase/(Decrease)
Purchased Power Costs	$ 16.6
Transmission Costs	11.6
Other	(2.4)
Total Purchased Power and Transmission	$ 25.8

Included in purchased power are the costs associated with WMECO's basic service charge and deferred energy supply costs. The basic service charge recovers energy-related costs incurred as a result of providing electric generation service supply to all customers that have not migrated to third party suppliers. The increase in purchased power was due primarily to higher average supply prices and increased load as a result of customers returning to basic service from third party suppliers. The increase in transmission costs was as a result of an increase in the retail transmission cost deferral, which reflects the actual costs of transmission service compared to estimated amounts billed to customers.

Operations and Maintenance expense includes tracked costs and costs that are part of base distribution rates with changes impacting earnings (non-tracked costs). Operations and Maintenance decreased in 2014, as compared to 2013, driven by a $4.8 million reduction in non-tracked costs, which was primarily attributable to lower labor and other employee-related costs, and a $2 million reduction in tracked costs, which have no earnings impact, that was primarily attributable to lower labor and other employee-related costs, including pension costs.

Depreciation increased in 2014, as compared to 2013, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets/(Liabilities), Net, reflects a decrease in the recovery of transition costs primarily due to the refund of the DOE damages proceeds to customers in 2014, as compared to 2013. Fluctuations in these costs are recovered from or refunded to customers in rates through cost tracking mechanisms and have no impact on earnings.

Amortization of Rate Reduction Bonds decreased in 2014, as compared to 2013, due to the maturity of the RRBs in June 2013.

Energy Efficiency Programs, which are tracked costs, increased in 2014, as compared to 2013, due primarily to an increase in energy efficiency costs in accordance with the three-year program guidelines established by the DPU.

Taxes Other Than Income Taxes increased in 2014, as compared to 2013, due primarily to an increase in property taxes as a result of both an increase in utility plant balances and property tax rates.

Other Income, Net decreased in 2014, as compared to 2013, due primarily to lower unrealized gains on the assets supporting the deferred compensation plans ($1.4 million).

Income Tax Expense decreased in 2014, as compared to 2013, due primarily to lower pre-tax earnings.

EARNINGS SUMMARY

WMECO's earnings decreased in 2014, as compared to 2013, due primarily to the after-tax reserve recorded for the 2014 FERC ROE orders as compared to the reserve recorded in 2013 for the FERC ALJ initial decision in the FERC base ROE complaints, higher depreciation expense and higher property tax expense. Partially offsetting these unfavorable earnings impacts were a decrease in operations and maintenance expense primarily attributable to lower employee-related costs, and the reversal of a previously established wholesale billing adjustment.

LIQUIDITY

WMECO had cash flows provided by operating activities of $153.3 million in 2014, compared with $178.8 million in 2013. The decrease in operating cash flows was due primarily to higher income tax payments in 2014, as compared to 2013, and the absence of costs recovered in rates related to the RRBs that were fully amortized in 2013, partially offset by the favorable impact of changes in working capital and $18.9 million in DOE damages proceeds received in 2014 from the Yankee Companies associated with the spent nuclear fuel litigation.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

Commodity Price Risk Management: Our Regulated companies enter into energy contracts to serve our customers and the economic impacts of those contracts are passed on to our customers. Accordingly, the Regulated companies have no exposure to loss of future earnings or fair values due to these market risk-sensitive instruments. NU's Energy Supply Risk Committee, comprised of senior officers, reviews and approves all large scale energy related transactions entered into by its Regulated companies.

Other Risk Management Activities

We have an Enterprise Risk Management (ERM) program for identifying the principal risks of the Company. Our ERM program involves the application of a well-defined, enterprise-wide methodology designed to allow our Risk Committee, comprised of our senior officers and directors of the Company, to identify, categorize, prioritize, and mitigate the principal risks to the Company. The ERM program is integrated with other assurance functions throughout the Company including Compliance, Auditing, and Insurance to ensure appropriate coverage of risks that could impact the Company. In addition to known risks, ERM identifies emerging risks to the Company, through participation in industry groups, discussions with management and in consultation with outside advisers. Our management then analyzes risks to determine materiality, likelihood, impact and develops mitigation strategies. Management broadly considers our business model, the utility industry, the global economy and the current environment to identify risks. The findings of this process are periodically discussed with the Finance Committee of our Board of Trustees, as well as with other Board Committees or the full Board of Trustees, as appropriate, including reporting on how these issues are being measured and managed. The Finance Committee is responsible for oversight of the Company's ERM program and enterprise-wide risks as well as specific risks associated with insurance, credit, financing, investments, pensions and overall system security including cyber security. However, there can be no assurances that the Enterprise Risk Management process will identify or manage every risk or event that could impact our financial position, results of operations or cash flows.

Interest Rate Risk Management: We manage our interest rate risk exposure in accordance with our written policies and procedures by maintaining a mix of fixed and variable rate long-term debt. As of December 31, 2014, approximately 91 percent of our long-term debt, including fees and interest due for spent nuclear fuel disposal costs, was at a fixed interest rate. The remaining long-term debt is at variable interest rates and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in our variable interest rates, annual interest expense would have increased by a pre-tax amount of $7.7 million.

Credit Risk Management: Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of our contractual obligations. We serve a wide variety of customers and transact with suppliers that include IPPs, industrial companies, natural gas and electric utilities, oil and gas producers, financial institutions, and other energy marketers. Margin accounts exist within this diverse group, and we realize interest receipts and payments related to balances outstanding in these margin accounts. This wide customer and supplier mix generates a need for a variety of contractual structures, products and terms that, in turn, require us to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by our risk management process.

Our Regulated companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. Our Regulated companies manage the credit risk with these counterparties in accordance with established credit risk practices and monitor contracting risks, including credit risk. As of December 31, 2014, our Regulated companies held collateral from counterparties related to our standard service contracts. As of December 31, 2014, NU had cash posted with ISO-NE related to energy purchase transactions.

For further information on cash collateral deposited and posted with counterparties, see Note 1G, "Summary of Significant Accounting Policies - Restricted Cash and Other Deposits," and Note 4, "Derivative Instruments," to the financial statements.

If the respective unsecured debt ratings of NU or its subsidiaries were reduced to below investment grade by either Moody's or S&P, certain of NU's contracts would require additional collateral in the form of cash to be provided to counterparties and independent system operators. NU would have been and remains able to provide that collateral.

Item 8. Financial Statements and Supplementary Data

NU

Company Report on Internal Controls Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Consolidated Financial Statements

CL&P

Company Report on Internal Controls Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Financial Statements

NSTAR Electric

Company Report on Internal Controls Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Consolidated Financial Statements

PSNH

Company Report on Internal Controls Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Consolidated Financial Statements

WMECO

Company Report on Internal Controls Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Financial Statements

Company Report on Internal Controls Over Financial Reporting

Northeast Utilities

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of Northeast Utilities and subsidiaries (NU or the Company) and of other sections of this annual report. NU's internal controls over financial reporting were audited by Deloitte & Touche LLP.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, NU conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2014.

February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the accompanying consolidated balance sheets of Northeast Utilities and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedules listed in the Index at Item 15 of Part IV. We also have audited the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Company Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
February 25, 2015

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2014	2013
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 38,703	$ 43,364
Receivables, Net	856,346	765,391
Unbilled Revenues	211,758	224,982
Taxes Receivable	337,307	16,629
Fuel, Materials and Supplies	349,664	303,233
Regulatory Assets	672,493	535,791
Prepayments and Other Current Assets	226,194	197,659
Total Current Assets	2,692,465	2,087,049
Property, Plant and Equipment, Net	18,647,041	17,576,186
Deferred Debits and Other Assets:		
Regulatory Assets	4,054,086	3,758,694
Goodwill	3,519,401	3,519,401
Marketable Securities	515,025	488,515
Other Long-Term Assets	349,957	365,692
Total Deferred Debits and Other Assets	8,438,469	8,132,302
Total Assets	$ 29,777,975	$ 27,795,537
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 956,825	$ 1,093,000
Long-Term Debt - Current Portion	245,583	533,346
Accounts Payable	868,231	742,251
Regulatory Liabilities	235,022	204,278
Other Current Liabilities	828,720	702,776
Total Current Liabilities	3,134,381	3,275,651
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	4,467,473	4,029,026
Regulatory Liabilities	515,144	502,984
Derivative Liabilities	409,632	624,050
Accrued Pension, SERP and PBOP	1,638,558	896,844
Other Long-Term Liabilities	874,387	923,053
Total Deferred Credits and Other Liabilities	7,905,194	6,975,957
Capitalization:		
Long-Term Debt	8,606,017	7,776,833
Noncontrolling Interest - Preferred Stock of Subsidiaries	155,568	155,568
Equity:		
Common Shareholders' Equity:		
Common Shares	1,666,796	1,665,351
Capital Surplus, Paid In	6,235,834	6,192,765
Retained Earnings	2,448,661	2,125,980
Accumulated Other Comprehensive Loss	(74,009)	(46,031)
Treasury Stock	(300,467)	(326,537)
Common Shareholders' Equity	9,976,815	9,611,528
Total Capitalization	18,738,400	17,543,929
Commitments and Contingencies (Note 11)		
Total Liabilities and Capitalization	$ 29,777,975	$ 27,795,537

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars, Except Share Information)	For the Years Ended December 31, 2014	2013	2012
Operating Revenues	$ 7,741,856	$ 7,301,204	$ 6,273,787
Operating Expenses:			
Purchased Power, Fuel and Transmission	3,021,550	2,482,954	2,084,364
Operations and Maintenance	1,427,589	1,514,986	1,583,070
Depreciation	614,657	610,777	519,010
Amortization of Regulatory Assets, Net	10,704	206,322	79,762
Amortization of Rate Reduction Bonds	-	42,581	142,019
Energy Efficiency Programs	473,127	401,919	313,149
Taxes Other Than Income Taxes	561,380	512,230	434,207
Total Operating Expenses	6,109,007	5,771,769	5,155,581
Operating Income	1,632,849	1,529,435	1,118,206
Interest Expense:			
Interest on Long-Term Debt	345,001	340,970	316,987
Interest on Rate Reduction Bonds	-	422	6,168
Other Interest	17,105	(2,693)	6,790
Interest Expense	362,106	338,699	329,945
Other Income, Net	24,619	29,894	19,742
Income Before Income Tax Expense	1,295,362	1,220,630	808,003
Income Tax Expense	468,297	426,941	274,926
Net Income	827,065	793,689	533,077
Net Income Attributable to Noncontrolling Interests	7,519	7,682	7,132
Net Income Attributable to Controlling Interest	$ 819,546	$ 786,007	$ 525,945
Basic Earnings Per Common Share	$ 2.59	$ 2.49	$ 1.90
Diluted Earnings Per Common Share	$ 2.58	$ 2.49	$ 1.89
Weighted Average Common Shares Outstanding:			
Basic	316,136,748	315,311,387	277,209,819
Diluted	317,417,414	316,211,160	277,993,631

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	2014	2013	2012
Net Income	$ 827,065	$ 793,689	$ 533,077
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	2,037	2,049	1,971
Changes in Unrealized Gains/(Losses) on Other Securities	315	(940)	217
Changes in Funded Status of Pension, SERP and PBOP Benefit Plans	(30,330)	25,714	(4,356)
Other Comprehensive Income/(Loss), Net of Tax	(27,978)	26,823	(2,168)
Comprehensive Income Attributable to Noncontrolling Interests	(7,519)	(7,682)	(7,132)
Comprehensive Income Attributable to Controlling Interest	$ 791,568	$ 812,830	$ 523,777

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Shares		Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
(Thousands of Dollars, Except Share Information)	Shares	Amount					
Balance as of January 1, 2012	177,158,692	$ 980,264	$ 1,797,884	$ 1,651,875	$ (70,686)	$ (346,667)	$ 4,012,670
Net Income				533,077			533,077
Shares Issued in Connection with NSTAR Merger	136,048,595	680,243	4,358,027				5,038,270
Other Equity Impacts of Merger with NSTAR			2,938	421			3,359
Dividends on Common Shares - $1.32 Per Share				(375,527)			(375,527)
Dividends on Preferred Stock				(7,029)			(7,029)
Issuance of Common Shares, $5 Par Value	408,018	2,040	11,287				13,327
Long-Term Incentive Plan Activity			(3,897)				(3,897)
Issuance of Treasury Shares to Fund ESOP	438,329		8,454			8,043	16,497
Other Changes in Shareholders' Equity			8,574				8,574
Net Income Attributable to Noncontrolling Interests				(103)			(103)
Other Comprehensive Loss					(2,168)		(2,168)
Balance as of December 31, 2012	314,053,634	1,662,547	6,183,267	1,802,714	(72,854)	(338,624)	9,237,050
Net Income				793,689			793,689
Dividends on Common Shares - $1.47 Per Share				(462,741)			(462,741)
Dividends on Preferred Stock				(7,682)			(7,682)
Issuance of Common Shares, $5 Par Value	560,848	2,804	8,274				11,078
Long-Term Incentive Plan Activity			(10,748)				(10,748)
Issuance of Treasury Shares	659,077		17,381			12,087	29,468
Other Changes in Shareholders' Equity			(5,409)				(5,409)
Other Comprehensive Income					26,823		26,823
Balance as of December 31, 2013	315,273,559	1,665,351	6,192,765	2,125,980	(46,031)	(326,537)	9,611,528
Net Income				827,065			827,065
Dividends on Common Shares - $1.57 Per Share				(496,524)			(496,524)
Dividends on Preferred Stock				(7,519)			(7,519)
Issuance of Common Shares, $5 Par Value	288,941	1,445	5,164				6,609
Long-Term Incentive Plan Activity			(9,569)				(9,569)
Issuance of Treasury Shares	1,420,837		37,817			26,070	63,887
Other Changes in Shareholders' Equity			9,657	(341)			9,316
Other Comprehensive Loss					(27,978)		(27,978)
Balance as of December 31, 2014	316,983,337	$ 1,666,796	$ 6,235,834	$ 2,448,661	$ (74,009)	$ (300,467)	$ 9,976,815

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Activities:			
Net Income	$ 827,065	$ 793,689	$ 533,077
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	614,657	610,777	519,010
Deferred Income Taxes	443,259	431,413	292,000
Pension, SERP and PBOP Expense	99,056	195,698	218,540
Pension and PBOP Contributions	(211,649)	(342,184)	(295,028)
Regulatory Over/(Under) Recoveries, Net	6,853	(24,276)	(259,853)
Amortization of Regulatory Assets, Net	10,704	206,322	79,762
Amortization of Rate Reduction Bonds	-	42,581	142,019
Proceeds from DOE Damages Claim, Net	132,138	-	-
Other	39,523	56,071	42,852
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(122,139)	(163,549)	(20,214)
Fuel, Materials and Supplies	(41,310)	(14,811)	34,321
Taxes Receivable/Accrued, Net	(323,224)	(50,950)	(5,450)
Accounts Payable	144,743	(54,619)	(128,339)
Other Current Assets and Liabilities, Net	15,797	(22,623)	8,532
Net Cash Flows Provided by Operating Activities	1,635,473	1,663,539	1,161,229
Investing Activities:			
Investments in Property, Plant and Equipment	(1,603,744)	(1,456,787)	(1,472,272)
Proceeds from Sales of Marketable Securities	488,789	627,532	317,294
Purchases of Marketable Securities	(491,220)	(679,784)	(348,629)
Other Investing Activities	14,380	67,816	35,683
Net Cash Flows Used in Investing Activities	(1,591,795)	(1,441,223)	(1,467,924)
Financing Activities:			
Cash Dividends on Common Shares	(475,227)	(462,741)	(375,047)
Cash Dividends on Preferred Stock	(7,519)	(7,682)	(7,029)
Increase/(Decrease) in Short-Term Debt	285,075	(397,000)	825,000
Issuance of Long-Term Debt	725,000	1,680,000	850,000
Retirements of Long-Term Debt	(576,551)	(929,885)	(839,136)
Retirements of Rate Reduction Bonds	-	(82,139)	(114,433)
Other Financing Activities	883	(25,253)	6,529
Net Cash Flows (Used in)/Provided by Financing Activities	(48,339)	(224,700)	345,884
Net (Decrease)/Increase in Cash and Cash Equivalents	(4,661)	(2,384)	39,189
Cash and Cash Equivalents - Beginning of Year	43,364	45,748	6,559
Cash and Cash Equivalents - End of Year	$ 38,703	$ 43,364	$ 45,748

The accompanying notes are an integral part of these consolidated financial statements.

Company Report on Internal Controls Over Financial Reporting

The Connecticut Light and Power Company

Management is responsible for the preparation, integrity, and fair presentation of the accompanying financial statements of The Connecticut Light and Power Company (CL&P or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, CL&P conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2014.

February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of The Connecticut Light and Power Company:

We have audited the accompanying balance sheets of The Connecticut Light and Power Company (the "Company") as of December 31, 2014 and 2013, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of The Connecticut Light and Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
February 25, 2015

THE CONNECTICUT LIGHT AND POWER COMPANY
BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2014	2013
ASSETS		
Current Assets:		
Cash	$ 2,356	$ 7,237
Receivables, Net	355,140	319,670
Accounts Receivable from Affiliated Companies	16,757	13,777
Unbilled Revenues	102,137	92,401
Taxes Receivable	116,148	20,041
Regulatory Assets	220,344	150,943
Materials and Supplies	46,664	54,606
Prepayments and Other Current Assets	37,822	33,041
Total Current Assets	897,368	691,716
Property, Plant and Equipment, Net	6,809,664	6,451,259
Deferred Debits and Other Assets:		
Regulatory Assets	1,475,508	1,663,147
Other Long-Term Assets	177,568	174,380
Total Deferred Debits and Other Assets	1,653,076	1,837,527
Total Assets	$ 9,360,108	$ 8,980,502
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to NU Parent	$ 133,400	$ 287,300
Long-Term Debt - Current Portion	162,000	150,000
Accounts Payable	272,971	201,047
Accounts Payable to Affiliated Companies	65,594	56,531
Obligations to Third Party Suppliers	73,624	73,914
Regulatory Liabilities	124,722	93,961
Derivative Liabilities	88,459	92,233
Other Current Liabilities	153,420	134,716
Total Current Liabilities	1,074,190	1,089,702
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,642,805	1,510,586
Regulatory Liabilities	81,298	93,757
Derivative Liabilities	406,199	617,072
Accrued Pension, SERP and PBOP	273,854	95,895
Other Long-Term Liabilities	148,844	163,588
Total Deferred Credits and Other Liabilities	2,553,000	2,480,898
Capitalization:		
Long-Term Debt	2,679,951	2,591,208
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common Stock	60,352	60,352
Capital Surplus, Paid In	1,804,869	1,682,047
Retained Earnings	1,072,477	961,482
Accumulated Other Comprehensive Loss	(931)	(1,387)
Common Stockholder's Equity	2,936,767	2,702,494
Total Capitalization	5,732,918	5,409,902
Commitments and Contingencies (Note 11)		
Total Liabilities and Capitalization	$ 9,360,108	$ 8,980,502

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY
STATEMENTS OF INCOME

(Thousands of Dollars)	2014	2013	2012
	For the Years Ended December 31,		
Operating Revenues	$ 2,692,582	$ 2,442,341	$ 2,407,449
Operating Expenses:			
Purchased Power and Transmission	982,876	872,769	858,231
Operations and Maintenance	494,578	523,247	635,733
Depreciation	188,837	177,603	166,853
Amortization of Regulatory Assets, Net	59,336	4,870	14,372
Energy Efficiency Programs	156,335	89,858	89,299
Taxes Other Than Income Taxes	255,370	234,418	215,972
Total Operating Expenses	2,137,332	1,902,765	1,980,460
Operating Income	555,250	539,576	426,989
Interest Expense:			
Interest on Long-Term Debt	135,656	130,620	124,894
Other Interest	11,765	3,030	8,233
Interest Expense	147,421	133,650	133,127
Other Income, Net	13,376	15,149	10,300
Income Before Income Tax Expense	421,205	421,075	304,162
Income Tax Expense	133,451	141,663	94,437
Net Income	$ 287,754	$ 279,412	$ 209,725

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 287,754	$ 279,412	$ 209,725
Other Comprehensive Income, Net of Tax:			
Qualified Cash Flow Hedging Instruments	444	444	444
Changes in Unrealized Gains/(Losses) on Other Securities	12	(31)	7
Other Comprehensive Income, Net of Tax	456	413	451
Comprehensive Income	$ 288,210	$ 279,825	$ 210,176

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Stock Information)	Common Stock		Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
	Stock	Amount				
Balance as of January 1, 2012	6,035,205	$ 60,352	$ 1,613,503	$ 735,948	$ (2,251)	$ 2,407,552
Net Income				209,725		209,725
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(100,486)		(100,486)
Allocation of Benefits - ESOP			1,595			1,595
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			25,000			25,000
Other Comprehensive Income					451	451
Balance as of December 31, 2012	6,035,205	60,352	1,640,149	839,628	(1,800)	2,538,329
Net Income				279,412		279,412
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(151,999)		(151,999)
Allocation of Benefits - ESOP			1,847			1,847
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			40,000			40,000
Other Comprehensive Income					413	413
Balance as of December 31, 2013	6,035,205	60,352	1,682,047	961,482	(1,387)	2,702,494
Net Income				287,754		287,754
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(171,200)		(171,200)
Allocation of Benefits - ESOP			2,771			2,771
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			120,000			120,000
Other Comprehensive Income					456	456
Balance as of December 31, 2014	6,035,205	$ 60,352	$ 1,804,869	$ 1,072,477	$ (931)	$ 2,936,767

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY
STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Activities:			
Net Income	$ 287,754	$ 279,412	$ 209,725
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	188,837	177,603	166,853
Deferred Income Taxes	130,949	130,038	140,993
Pension, SERP and PBOP Expense, Net of PBOP Contributions	14,992	24,416	24,062
Regulatory (Under)/Over Recoveries, Net	(20,502)	28,298	(100,505)
Amortization of Regulatory Assets, Net	59,336	4,870	14,372
Proceeds from DOE Damages Claim	68,610	-	-
Other	(1,342)	(3,478)	(28,952)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(78,631)	(56,593)	(7,741)
Materials and Supplies	13,063	9,997	(4,573)
Taxes Receivable/Accrued, Net	(126,376)	(41,594)	15,702
Accounts Payable	68,891	(66,225)	(190,240)
Other Current Assets and Liabilities, Net	6,838	8,513	(27,803)
Net Cash Flows Provided by Operating Activities	612,419	495,257	211,893
Investing Activities:			
Investments in Property, Plant and Equipment	(515,710)	(434,934)	(449,137)
Other Investing Activities	12,653	2,650	32,009
Net Cash Flows Used in Investing Activities	(503,057)	(432,284)	(417,128)
Financing Activities:			
Cash Dividends on Common Stock	(171,200)	(151,999)	(100,486)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
(Decrease)/Increase in Short-Term Debt	-	(89,000)	58,000
(Decrease)/Increase in Notes Payable to NU Parent	(153,900)	(117,800)	346,575
Issuance of Long-Term Debt	250,000	400,000	-
Retirements of Long-Term Debt	(150,000)	(125,000)	(116,400)
Capital Contributions from NU Parent	120,000	40,000	25,000
Other Financing Activities	(3,584)	(6,379)	(1,895)
Net Cash Flows (Used in)/Provided by Financing Activities	(114,243)	(55,737)	205,235
Net (Decrease)/Increase in Cash	(4,881)	7,236	-
Cash - Beginning of Year	7,237	1	1
Cash - End of Year	$ 2,356	$ 7,237	$ 1

The accompanying notes are an integral part of these financial statements.

Company Report on Internal Controls Over Financial Reporting

NSTAR Electric Company

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of NSTAR Electric Company and subsidiary (NSTAR Electric or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, NSTAR Electric conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2014.

February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NSTAR Electric Company:

We have audited the accompanying consolidated balance sheets of NSTAR Electric Company and subsidiary (the "Company") as of December 31, 2014 and 2013 and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of NSTAR Electric Company and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
February 25, 2015

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2014	2013
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 12,773	$ 8,021
Receivables, Net	234,481	209,711
Accounts Receivable from Affiliated Companies	40,353	27,264
Unbilled Revenues	29,741	41,368
Taxes Receivable	144,601	25,590
Materials and Supplies	74,179	44,236
Regulatory Assets	198,710	204,144
Prepayments and Other Current Assets	10,815	11,120
Total Current Assets	745,653	571,454
Property, Plant and Equipment, Net	5,335,436	5,043,887
Deferred Debits and Other Assets:		
Regulatory Assets	1,179,100	1,235,156
Other Long-Term Assets	73,051	60,624
Total Deferred Debits and Other Assets	1,252,151	1,295,780
Total Assets	$ 7,333,240	$ 6,911,121
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 302,000	$ 103,500
Long-Term Debt - Current Portion	4,700	301,650
Accounts Payable	217,311	202,100
Accounts Payable to Affiliated Companies	63,517	75,707
Accumulated Deferred Income Taxes	55,136	50,128
Regulatory Liabilities	49,611	53,958
Other Current Liabilities	186,513	123,869
Total Current Liabilities	878,788	910,912
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,527,667	1,466,835
Regulatory Liabilities	262,738	253,108
Accrued Pension, SERP and PBOP	235,529	118,010
Other Long-Term Liabilities	129,279	206,386
Total Deferred Credits and Other Liabilities	2,155,213	2,044,339
Capitalization:		
Long-Term Debt	1,792,712	1,499,417
Preferred Stock Not Subject to Mandatory Redemption	43,000	43,000
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	994,130	992,625
Retained Earnings	1,468,955	1,420,828
Accumulated Other Comprehensive Income	442	-
Common Stockholder's Equity	2,463,527	2,413,453
Total Capitalization	4,299,239	3,955,870
Commitments and Contingencies (Note 11)		
Total Liabilities and Capitalization	$ 7,333,240	$ 6,911,121

The accompanying notes are an integral part of these consolidated financial statements.

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Revenues	$ 2,536,677	$ 2,493,479	$ 2,300,997
Operating Expenses:			
Purchased Power and Transmission	1,122,298	849,149	788,252
Operations and Maintenance	326,972	376,360	431,802
Depreciation	188,693	180,298	171,070
Amortization of Regulatory Assets/(Liabilities), Net	(6,330)	230,148	117,682
Amortization of Rate Reduction Bonds	-	15,054	90,322
Energy Efficiency Programs	193,516	206,536	201,234
Taxes Other Than Income Taxes	133,072	127,778	119,219
Total Operating Expenses	1,958,221	1,985,323	1,919,581
Operating Income	578,456	508,156	381,416
Interest Expense:			
Interest on Long-Term Debt	77,140	79,088	87,100
Interest on Rate Reduction Bonds	-	399	3,585
Other Interest	738	(9,104)	(20,631)
Interest Expense	77,878	70,383	70,054
Other Income, Net	4,491	3,639	2,846
Income Before Income Tax Expense	505,069	441,412	314,208
Income Tax Expense	201,981	172,866	123,966
Net Income	$ 303,088	$ 268,546	$ 190,242

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	2014	2013	2012
Net Income	$ 303,088	$ 268,546	$ 190,242
Other Comprehensive Income, Net of Tax:			
Changes in Funded Status of SERP Benefit Plan	442	-	-
Other Comprehensive Income, Net of Tax	442	-	-
Comprehensive Income	$ 303,530	$ 268,546	$ 190,242

The accompanying notes are an integral part of these consolidated financial statements.

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Stock Information)	Common Stock: Stock	Common Stock: Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income	Total Common Stockholder's Equity
Balance as of January 1, 2012	100	$ -	$ 992,625	$ 1,239,123	$ -	$ 2,231,748
Net Income				190,242		190,242
Dividends on Preferred Stock				(1,960)		(1,960)
Dividends on Common Stock				(217,000)		(217,000)
Balance as of December 31, 2012	100	-	992,625	1,210,405	-	2,203,030
Net Income				268,546		268,546
Dividends on Preferred Stock				(2,123)		(2,123)
Dividends on Common Stock				(56,000)		(56,000)
Balance as of December 31, 2013	100	–	992,625	1,420,828	-	2,413,453
Net Income				303,088		303,088
Dividends on Preferred Stock				(1,961)		(1,961)
Dividends on Common Stock				(253,000)		(253,000)
Other Changes in Stockholder's Equity			1,505			1,505
Accumulated Other Comprehensive Income					442	442
Balance as of December 31, 2014	100	$ -	$ 994,130	$ 1,468,955	$ 442	$ 2,463,527

The accompanying notes are an integral part of these consolidated financial statements.

NSTAR ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Activities:			
Net Income	$ 303,088	$ 268,546	$ 190,242
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	188,693	180,298	171,070
Deferred Income Taxes	108,133	48,808	4,264
Pension and PBOP Expense	6,760	35,731	66,010
Pension and PBOP Contributions	(120,306)	(82,000)	(25,000)
Regulatory Over/(Under) Recoveries, Net	57,696	(119,433)	(16,129)
Amortization of Regulatory (Liabilities)/Assets, Net	(6,330)	230,148	117,682
Amortization of Rate Reduction Bonds	-	15,054	90,322
Bad Debt Expense	24,740	28,108	40,301
Proceeds from DOE Damages Claim	30,193	-	-
Other	(51,478)	4,428	(32,048)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(18,853)	(45,405)	(10,496)
Materials and Supplies	(29,943)	3,227	1,813
Taxes Receivable/Accrued, Net	(122,746)	(38,003)	29,899
Accounts Payable	9,753	31,875	2,662
Accounts Receivable from/Payable to Affiliates, Net	115,092	(44,491)	(61,879)
Other Current Assets and Liabilities, Net	38,535	(6,468)	22,568
Net Cash Flows Provided by Operating Activities	533,027	510,423	591,281
Investing Activities:			
Investments in Property, Plant and Equipment	(465,028)	(476,600)	(414,089)
Decrease in Special Deposits	-	37,604	3,060
Other Investing Activities	-	400	400
Net Cash Flows Used in Investing Activities	(465,028)	(438,596)	(410,629)
Financing Activities:			
Cash Dividends on Common Stock	(253,000)	(56,000)	(217,000)
Cash Dividends on Preferred Stock	(1,961)	(2,123)	(1,960)
Increase/(Decrease) in Short-Term Debt	198,500	(172,500)	134,500
Issuance of Long-Term Debt	300,000	200,000	400,000
Retirements of Long-Term Debt	(301,650)	(1,650)	(401,650)
Retirements of Rate Reduction Bonds	-	(43,493)	(84,367)
Other Financing Activities	(5,136)	(1,735)	(5,853)
Net Cash Flows Used in Financing Activities	(63,247)	(77,501)	(176,330)
Net Increase/(Decrease) in Cash and Cash Equivalents	4,752	(5,674)	4,322
Cash and Cash Equivalents - Beginning of Year	8,021	13,695	9,373
Cash and Cash Equivalents - End of Year	$ 12,773	$ 8,021	$ 13,695

The accompanying notes are an integral part of these consolidated financial statements.

Company Report on Internal Controls Over Financial Reporting

Public Service Company of New Hampshire

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of Public Service Company of New Hampshire and subsidiary (PSNH or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, PSNH conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2014.

February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of Public Service Company of New Hampshire:

We have audited the accompanying consolidated balance sheets of Public Service Company of New Hampshire and subsidiary (the "Company") as of December 31, 2014 and 2013 and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Company of New Hampshire and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
February 25, 2015

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2014	2013
ASSETS		
Current Assets:		
Cash	$ 489	$ 130
Receivables, Net	80,151	76,331
Accounts Receivable from Affiliated Companies	3,194	90
Unbilled Revenues	40,181	38,344
Fuel, Materials and Supplies	148,139	128,736
Regulatory Assets	111,705	92,194
Prepayments and Other Current Assets	42,392	24,100
Total Current Assets	426,251	359,925
Property, Plant and Equipment, Net	2,635,844	2,467,556
Deferred Debits and Other Assets:		
Regulatory Assets	293,115	219,346
Other Long-Term Assets	39,228	39,891
Total Deferred Debits and Other Assets	332,343	259,237
Total Assets	$ 3,394,438	$ 3,086,718
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to NU Parent	$ 90,500	$ 86,500
Long-Term Debt - Current Portion	-	50,000
Accounts Payable	93,349	82,920
Accounts Payable to Affiliated Companies	33,734	22,040
Regulatory Liabilities	16,044	20,643
Accumulated Deferred Income Taxes	36,164	28,596
Other Current Liabilities	38,969	51,729
Total Current Liabilities	308,760	342,428
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	587,292	500,166
Regulatory Liabilities	51,372	51,723
Accrued Pension, SERP and PBOP	93,243	15,272
Other Long-Term Liabilities	50,155	46,247
Total Deferred Credits and Other Liabilities	782,062	613,408
Capitalization:		
Long-Term Debt	1,076,286	999,006
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	748,240	701,911
Retained Earnings	486,459	438,515
Accumulated Other Comprehensive Loss	(7,369)	(8,550)
Common Stockholder's Equity	1,227,330	1,131,876
Total Capitalization	2,303,616	2,130,882
Commitments and Contingencies (Note 11)		
Total Liabilities and Capitalization	$ 3,394,438	$ 3,086,718

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Revenues	$ 959,500	$ 935,402	$ 988,013
Operating Expenses:			
Purchased Power, Fuel and Transmission	313,732	269,754	319,253
Operations and Maintenance	261,848	267,797	263,234
Depreciation	98,436	91,581	87,602
Amortization of Regulatory Liabilities, Net	(29,602)	(20,387)	(24,086)
Amortization of Rate Reduction Bonds	-	19,748	56,645
Energy Efficiency Programs	14,286	14,494	14,245
Taxes Other Than Income Taxes	71,417	67,196	66,025
Total Operating Expenses	730,117	710,183	782,918
Operating Income	229,383	225,219	205,095
Interest Expense:			
Interest on Long-Term Debt	45,116	44,370	46,228
Interest on Rate Reduction Bonds	-	(154)	2,687
Other Interest	233	1,960	1,313
Interest Expense	45,349	46,176	50,228
Other Income, Net	2,045	3,455	3,008
Income Before Income Tax Expense	186,079	182,498	157,875
Income Tax Expense	72,135	71,101	60,993
Net Income	$ 113,944	$ 111,397	$ 96,882

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	2014	2013	2012
Net Income	$ 113,944	$ 111,397	$ 96,882
Other Comprehensive Income, Net of Tax:			
Qualified Cash Flow Hedging Instruments	1,162	1,162	1,162
Changes in Unrealized Gains/(Losses) on Other Securities	19	(54)	13
Changes in Funded Status of SERP Benefit Plan	-	(3)	2
Other Comprehensive Income, Net of Tax	1,181	1,105	1,177
Comprehensive Income	$ 115,125	$ 112,502	$ 98,059

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Stock Information)	Common Stock Stock	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
Balance as of January 1, 2012	301	$ -	$ 700,285	$ 388,910	$ (10,832)	$ 1,078,363
Net Income				96,882		96,882
Dividends on Common Stock				(90,674)		(90,674)
Allocation of Benefits - ESOP			767			767
Other Comprehensive Income					1,177	1,177
Balance as of December 31, 2012	301	-	701,052	395,118	(9,655)	1,086,515
Net Income				111,397		111,397
Dividends on Common Stock				(68,000)		(68,000)
Allocation of Benefits - ESOP			859			859
Other Comprehensive Income					1,105	1,105
Balance as of December 31, 2013	301	-	701,911	438,515	(8,550)	1,131,876
Net Income				113,944		113,944
Dividends on Common Stock				(66,000)		(66,000)
Capital Contributions from NU Parent			45,000			45,000
Allocation of Benefits - ESOP			1,329			1,329
Other Comprehensive Income					1,181	1,181
Balance as of December 31, 2014	301	$ -	$ 748,240	$ 486,459	$ (7,369)	$ 1,227,330

The accompanying notes are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Activities:			
Net Income	$ 113,944	$ 111,397	$ 96,882
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Depreciation	98,436	91,581	87,602
Deferred Income Taxes	94,813	75,693	58,552
Pension, SERP and PBOP Expense	7,197	26,846	26,312
Pension and PBOP Contributions	(2,482)	(112,964)	(96,880)
Regulatory Underrecoveries, Net	(11,875)	(8,481)	(183)
Amortization of Regulatory Liabilities, Net	(29,602)	(20,387)	(24,086)
Amortization of Rate Reduction Bonds	-	19,748	56,645
Proceeds from DOE Damages Claim	14,453	-	-
Other	10,095	16,079	11,205
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(15,576)	2,412	(84)
Fuel, Materials and Supplies	(19,403)	(33,391)	25,897
Taxes Receivable/Accrued, Net	(23,857)	26,462	(9,752)
Accounts Payable	17,796	2,632	(15,248)
Other Current Assets and Liabilities, Net	(5,972)	(9,520)	13,436
Net Cash Flows Provided by Operating Activities	247,967	188,107	230,298
Investing Activities:			
Investments in Property, Plant and Equipment	(256,159)	(186,009)	(203,902)
Decrease in Notes Receivable from Affiliate	-	-	55,900
(Increase)/Decrease in Special Deposits	(1,013)	22,040	4,200
Other Investing Activities	(139)	(88)	(135)
Net Cash Flows Used in Investing Activities	(257,311)	(164,057)	(143,937)
Financing Activities:			
Cash Dividends on Common Stock	(66,000)	(68,000)	(90,674)
Increase in Short-Term Debt	4,000	23,200	-
Issuance of Long-Term Debt	75,000	250,000	-
Retirements of Long-Term Debt	(50,000)	(198,235)	-
Retirements of Rate Reduction Bonds	-	(29,294)	(56,074)
Increase in Notes Payable to NU Parent	-	-	63,300
Capital Contributions from NU Parent	45,000	-	-
Other Financing Activities	1,703	(4,084)	(476)
Net Cash Flows Provided by/(Used in) Financing Activities	9,703	(26,413)	(83,924)
Net Increase/(Decrease) in Cash	359	(2,363)	2,437
Cash - Beginning of Year	130	2,493	56
Cash - End of Year	$ 489	$ 130	$ 2,493

The accompanying notes are an integral part of these consolidated financial statements.

Company Report on Internal Controls Over Financial Reporting

Western Massachusetts Electric Company

Management is responsible for the preparation, integrity, and fair presentation of the accompanying financial statements of Western Massachusetts Electric Company (WMECO or the Company) and of other sections of this annual report.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of the principal executive officer and principal financial officer, WMECO conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting were effective as of December 31, 2014.

February 25, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of Western Massachusetts Electric Company:

We have audited the accompanying balance sheets of Western Massachusetts Electric Company (the "Company") as of December 31, 2014 and 2013 and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15 of Part IV. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Western Massachusetts Electric Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
February 25, 2015

WESTERN MASSACHUSETTS ELECTRIC COMPANY
BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2014	2013
ASSETS		
Current Assets:		
Receivables, Net	$ 51,066	$ 49,018
Accounts Receivable from Affiliated Companies	7,851	47,607
Unbilled Revenues	15,146	16,562
Taxes Receivable	18,126	432
Regulatory Assets	51,923	43,024
Marketable Securities	28,658	26,628
Prepayments and Other Current Assets	7,607	10,479
Total Current Assets	180,377	193,750
Property, Plant and Equipment, Net	1,461,321	1,381,060
Deferred Debits and Other Assets:		
Regulatory Assets	146,307	146,088
Marketable Securities	29,452	31,243
Other Long-Term Assets	22,018	40,679
Total Deferred Debits and Other Assets	197,777	218,010
Total Assets	$ 1,839,475	$ 1,792,820
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to NU Parent	$ 21,400	$ -
Long-Term Debt - Current Portion	50,000	-
Accounts Payable	53,732	62,961
Accounts Payable to Affiliated Companies	14,328	9,230
Accrued Interest	7,526	7,525
Regulatory Liabilities	22,486	19,858
Accumulated Deferred Income Taxes	18,089	13,098
Counterparty Deposits	3,376	7,688
Other Current Liabilities	13,178	20,629
Total Current Liabilities	204,115	140,989
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	416,822	396,933
Regulatory Liabilities	10,835	13,873
Accrued Pension, SERP and PBOP	17,705	3,911
Other Long-Term Liabilities	33,747	28,619
Total Deferred Credits and Other Liabilities	479,109	443,336
Capitalization:		
Long-Term Debt	578,471	629,389
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	391,256	390,743
Retained Earnings	178,834	181,014
Accumulated Other Comprehensive Loss	(3,176)	(3,517)
Common Stockholder's Equity	577,780	579,106
Total Capitalization	1,156,251	1,208,495
Commitments and Contingencies (Note 11)		
Total Liabilities and Capitalization	$ 1,839,475	$ 1,792,820

The accompanying notes are an integral part of these financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Revenues	$ 493,423	$ 472,724	$ 441,164
Operating Expenses:			
Purchased Power and Transmission	172,876	147,059	136,086
Operations and Maintenance	89,406	96,194	97,031
Depreciation	41,886	37,568	29,971
Amortization of Regulatory Assets/(Liabilities), Net	(6,228)	(3,206)	410
Amortization of Rate Reduction Bonds	-	7,780	17,632
Energy Efficiency Programs	42,937	39,524	27,802
Taxes Other Than Income Taxes	34,907	28,458	21,458
Total Operating Expenses	375,784	353,377	330,390
Operating Income	117,639	119,347	110,774
Interest Expense:			
Interest on Long-Term Debt	24,245	23,625	23,462
Interest on Rate Reduction Bonds	-	177	1,229
Other Interest	686	1,049	1,943
Interest Expense	24,931	24,851	26,634
Other Income, Net	2,379	3,310	2,503
Income Before Income Tax Expense	95,087	97,806	86,643
Income Tax Expense	37,268	37,368	32,140
Net Income	$ 57,819	$ 60,438	$ 54,503

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 57,819	$ 60,438	$ 54,503
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	338	338	338
Changes in Unrealized Gains/(Losses) on Other Securities	3	(9)	2
Other Comprehensive Income/(Loss), Net of Tax	341	329	340
Comprehensive Income	$ 58,160	$ 60,767	$ 54,843

The accompanying notes are an integral part of these financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Stock Information)	Common Stock		Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
	Stock	Amount				
Balance as of January 1, 2012	434,653	$ 10,866	$ 340,115	$ 115,506	$ (4,186)	$ 462,301
Net Income				54,503		54,503
Dividends on Common Stock				(9,432)		(9,432)
Allocation of Benefits - ESOP			297			297
Capital Contributions from NU Parent			50,000			50,000
Other Comprehensive Income					340	340
Balance as of December 31, 2012	434,653	10,866	390,412	160,577	(3,846)	558,009
Net Income				60,438		60,438
Dividends on Common Stock				(40,001)		(40,001)
Allocation of Benefits - ESOP			331			331
Other Comprehensive Income					329	329
Balance as of December 31, 2013	434,653	10,866	390,743	181,014	(3,517)	579,106
Net Income				57,819		57,819
Dividends on Common Stock				(59,999)		(59,999)
Allocation of Benefits - ESOP			513			513
Other Comprehensive Income					341	341
Balance as of December 31, 2014	434,653	$ 10,866	$ 391,256	$ 178,834	$ (3,176)	$ 577,780

The accompanying notes are an integral part of these financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2014	2013	2012
Operating Activities:			
Net Income	$ 57,819	$ 60,438	$ 54,503
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:			
Depreciation	41,886	37,568	29,971
Deferred Income Taxes	34,108	87,028	53,942
Regulatory Overrecoveries, Net	1,925	8,458	(19,152)
Amortization of Regulatory (Liabilities)/Assets, Net	(6,228)	(3,206)	410
Amortization of Rate Reduction Bonds	-	7,780	17,632
Proceeds from DOE Damages Claim	18,883	-	-
Other	(2,005)	3,381	(3,954)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	39,872	(53,292)	(8,896)
Materials and Supplies	(627)	865	(2,882)
Taxes Receivable/Accrued, Net	(22,454)	19,840	(8,311)
Accounts Payable	1,269	7,456	(19,297)
Other Current Assets and Liabilities, Net	(11,169)	2,491	581
Net Cash Flows Provided by Operating Activities	153,279	178,807	94,547
Investing Activities:			
Investments in Property, Plant and Equipment	(116,205)	(128,786)	(264,175)
Proceeds from Sales of Marketable Securities	73,198	70,778	79,769
Purchases of Marketable Securities	(73,888)	(71,390)	(80,529)
Decrease in Notes Receivable from Affiliate	-	-	11,000
Other Investing Activities	3,200	7,401	(28)
Net Cash Flows Used in Investing Activities	(113,695)	(121,997)	(253,963)
Financing Activities:			
Cash Dividends on Common Stock	(59,999)	(40,001)	(9,432)
Issuance of Long-Term Debt	-	80,000	150,000
Retirements of Long-Term Debt	-	(55,000)	(53,800)
Increase/(Decrease) in Notes Payable to NU Parent	21,400	(31,900)	31,900
Retirements of Rate Reduction Bonds	-	(9,352)	(17,540)
Capital Contributions from NU Parent	-	-	50,000
Other Financing Activities	(985)	(558)	8,288
Net Cash Flows (Used in)/Provided by Financing Activities	(39,584)	(56,811)	159,416
Net Decrease in Cash	-	(1)	-
Cash - Beginning of Year	-	1	1
Cash - End of Year	$ -	$ -	$ 1

The accompanying notes are an integral part of these financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY
WESTERN MASSACHUSETTS ELECTRIC COMPANY

COMBINED NOTES TO FINANCIAL STATEMENTS

Refer to the Glossary of Terms included in this combined Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About NU, CL&P, NSTAR Electric, PSNH and WMECO

NU Consolidated: NU is a public utility holding company primarily engaged through its wholly owned regulated utility subsidiaries in the energy delivery business. On April 10, 2012, NU acquired NSTAR and its subsidiaries. See Note 21, "Merger of NU and NSTAR," for further information regarding the merger. NU's wholly owned regulated utility subsidiaries consist of CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas. NU provides energy delivery service to approximately 3.6 million electric and natural gas customers through these six regulated utilities in Connecticut, Massachusetts and New Hampshire. On February 2, 2015, NU, CL&P, NSTAR Electric, PSNH and WMECO commenced doing business as Eversource Energy.

NU, CL&P, NSTAR Electric, PSNH and WMECO are reporting companies under the Securities Exchange Act of 1934. NU is a public utility holding company under the Public Utility Holding Company Act of 2005. Arrangements among the regulated electric companies and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. The Regulated companies are subject to regulation of rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P and Yankee Gas, the DPU for NSTAR Electric, WMECO and NSTAR Gas, and the NHPUC for PSNH).

Regulated Companies: CL&P, NSTAR Electric, PSNH and WMECO furnish franchised retail electric service in Connecticut, Massachusetts and New Hampshire. Yankee Gas and NSTAR Gas are engaged in the distribution and sale of natural gas to customers within Connecticut and central and eastern Massachusetts, respectively. CL&P, NSTAR Electric, PSNH and WMECO's results include the operations of their respective distribution and transmission businesses. PSNH and WMECO's distribution results include the operations of their respective generation businesses. NU also has a regulated subsidiary, NPT, which was formed to construct, own and operate the Northern Pass line, a HVDC transmission line from Québec to New Hampshire under development that will interconnect with a new HVDC transmission line being developed by a transmission subsidiary of HQ.

Other: NUSCO, NU's service company, Rocky River Realty Company, a wholly-owned real estate subsidiary of NU, Renewable Properties, Inc., a wholly-owned subsidiary of EETV, and Properties, Inc., a wholly-owned subsidiary of PSNH, provide support services to NU, including its regulated companies. Harbor Electric Energy Company, a wholly-owned subsidiary of NSTAR Electric, provides distribution service and ongoing support to the Massachusetts Water Resources Authority. Hopkinton LNG Corp, an indirect, wholly-owned subsidiary of NU, provides natural gas liquefaction, vaporization, and storage services for NSTAR Gas.

B. Basis of Presentation

The consolidated financial statements of NU, NSTAR Electric and PSNH include the accounts of each of their respective subsidiaries. Intercompany transactions have been eliminated in consolidation. The accompanying consolidated financial statements of NU, NSTAR Electric and PSNH and the financial statements of CL&P and WMECO are herein collectively referred to as the "financial statements."

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NU's consolidated financial information includes NSTAR and its subsidiaries' results of operations beginning April 10, 2012. The information disclosed for the year ended December 31, 2012 for NSTAR Electric is presented on a comparable basis.

NU consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's, PSNH's and WMECO's combined ownership interest in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation of the NU financial statements.

NU's utility subsidiaries are subject to the application of accounting guidance for entities with rate-regulated operations that considers the effect of regulation resulting from differences in the timing of the recognition of certain revenues and expenses from those of other businesses and industries. NU's utility subsidiaries' distribution, generation and transmission businesses and NPT are subject to rate-regulation that is based on cost recovery and meets the criteria for application of rate-regulated accounting. See Note 2, "Regulatory Accounting," for further information.

Certain reclassifications of prior year data were made in the accompanying balance sheets for NU, CL&P, NSTAR Electric and PSNH. These reclassifications were made to conform to the current year presentation.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, the Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric, which are not owned by NU or its consolidated subsidiaries and are not subject to mandatory redemption, have

been presented as noncontrolling interests in the financial statements of NU. The Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric are considered to be temporary equity and have been classified between liabilities and permanent shareholders' equity on the balance sheets of NU, CL&P and NSTAR Electric due to a provision in the preferred stock agreements of both CL&P and NSTAR Electric that grant preferred stockholders the right to elect a majority of the CL&P and NSTAR Electric Board of Directors, respectively, should certain conditions exist, such as if preferred dividends are in arrears for a specified amount of time. The Net Income reported in the statements of income and cash flows represents net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR Electric.

As of December 31, 2014 and 2013, NU's carrying amount of goodwill was approximately $3.5 billion. NU performs an assessment for possible impairment of its goodwill at least annually. NU completed its annual goodwill impairment test for each of its reporting units as of October 1, 2014 and determined that no impairment exists. See Note 22, "Goodwill," for further information.

C. Accounting Standards

Recently Adopted Accounting Standards: On January 1, 2014, as required, NU prospectively adopted the Financial Accounting Standards Board's (FASB) final Accounting Standards Updates (ASU) that required presentation of certain unrecognized tax benefits as reductions to deferred tax assets. Implementation of this guidance had an immaterial impact on the balance sheets and no impact on the results of operations or cash flows of NU, CL&P, NSTAR Electric, PSNH and WMECO.

Accounting Standards Issued but not Yet Adopted: In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, effective January 1, 2017, which amends existing revenue recognition guidance and is required to be applied retrospectively (either to each reporting period presented or cumulatively at the date of initial application). Management is reviewing the requirements of the ASU. The ASU's impact is not expected to have a material impact on the financial statements of NU, CL&P, NSTAR Electric, PSNH and WMECO.

D. Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, any overdraft amounts are reclassified from Cash and Cash Equivalents to Accounts Payable on the balance sheets.

E. Provision for Uncollectible Accounts

NU, including CL&P, NSTAR Electric, PSNH and WMECO, presents its receivables at estimated net realizable value by maintaining a provision for uncollectible accounts. This provision is determined based upon a variety of judgments and factors, including the application of an estimated uncollectible percentage to each receivable aging category. The estimate is based upon historical collection and write-off experience and management's assessment of collectability from customers. Management continuously assesses the collectability of receivables and adjusts collectability estimates based on actual experience. Receivable balances are written off against the provision for uncollectible accounts when the accounts are terminated and these balances are deemed to be uncollectible.

The PURA allows CL&P and Yankee Gas to accelerate the recovery of accounts receivable balances attributable to qualified customers under financial or medical duress (uncollectible hardship accounts receivable) outstanding for greater than 90 days. The DPU allows WMECO to also recover in rates amounts associated with certain uncollectible hardship accounts receivable. Uncollectible customer account balances, which are expected to be recovered in rates, are included in Regulatory Assets or Other Long-Term Assets.

The total provision for uncollectible accounts and for uncollectible hardship accounts, which is included in the total provision, are included in Receivables, Net on the balance sheets, and were as follows:

	Total Provision for Uncollectible Accounts		Uncollectible Hardship	
	As of December 31,		As of December 31,	
(Millions of Dollars)	2014	2013	2014	2013
NU	$ 175.3	$ 171.3	$ 91.5	$ 81.2
CL&P	84.3	82.0	74.0	67.3
NSTAR Electric	40.7	41.7	-	-
PSNH	7.7	7.4	-	-
WMECO	9.9	10.0	6.2	5.5

F. Fuel, Materials and Supplies and Allowance Inventory

Fuel, Materials and Supplies include natural gas, coal, biomass and oil inventories as well as materials purchased primarily for construction or operation and maintenance purposes. Natural gas, coal, biomass and oil inventories are valued at their respective weighted average cost. Materials and supplies are valued at the lower of average cost or market. As of December 31, 2014, NU and PSNH had $164.3 million and $95.1 million, respectively, of fuel and $185.4 million and $53 million, respectively, of materials and supplies. As of December 31, 2013, NU and PSNH had $139.5 million and $74.2 million, respectively, of fuel and $163.7 million and $54.5 million, respectively, of materials and supplies.

Fuel, Materials and Supplies also include Renewable Energy Certificates (RECs), which are purchased from suppliers of renewable sources of generation. RECs are used to meet state mandated Renewable Portfolio Standards requirements. As of December 31, 2014 and 2013, NSTAR Electric had $25.1 million and $4.9 million, respectively, of RECs classified as Materials and Supplies on the balance sheets.

PSNH is subject to federal and state laws and regulations that regulate emissions of air pollutants, including SO_2, CO_2, and NO_x related to its regulated generation units, and uses SO_2, CO_2, and NO_x emissions allowances. At the end of each compliance period, PSNH is required to relinquish SO_2, CO_2, and NO_x emissions allowances corresponding to the actual respective emissions emitted by its generating units over the compliance period. SO_2 and NO_x emissions allowances are obtained through an annual allocation from the federal and state regulators that are granted at no cost and through purchases from third parties. CO_2 emissions allowances are obtained through an annual allocation from the state regulator that are

granted at no cost and are acquired through auctions and through purchases from third parties. SO_2, CO_2, and NO_x emissions allowances are charged to expense based on their weighted average cost as they are utilized against emissions volumes at PSNH's generating units.

SO_2, CO_2, and NO_x emissions allowances are recorded within Fuel, Materials and Supplies and are classified on the balance sheet as short-term or long-term depending on the period in which they are expected to be utilized against actual emissions. As of December 31, 2014 and 2013, PSNH had $20.1 million and $19.4 million, respectively, of long-term SO_2 and CO_2 emissions allowances classified as Other Long-Term Assets on the balance sheets.

G. Restricted Cash and Other Deposits
As of December 31, 2014, NU, CL&P and PSNH had $3.2 million, $2.1 million, and $1 million, respectively, of restricted cash relating to amounts held in escrow, which were included in Prepayments and Other Current Assets on the balance sheets. As of December 31, 2013, these amounts were $1.7 million and $1.4 million for NU and CL&P, respectively.

As of December 31, 2014, NU, CL&P and PSNH had $9.9 million, $1.2 million and $2.5 million, respectively, of cash collateral posted not subject to master netting agreements, primarily with ISO-NE, which were included in Prepayments and Other Current Assets on the balance sheets. As of December 31, 2013, these amounts were $17.9 million and $9 million for NU and NSTAR Electric, respectively.

H. Fair Value Measurements
Fair value measurement guidance is applied to derivative contracts that are not elected or designated as "normal purchases or normal sales" (normal) and to the marketable securities held in trusts. Fair value measurement guidance is also applied to valuations of the investments used to calculate the funded status of pension and PBOP plans and nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs, and is also used to estimate the fair value of preferred stock and long-term debt.

Fair Value Hierarchy: In measuring fair value, NU uses observable market data when available and minimizes the use of unobservable inputs. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. NU evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and NU's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products.

Determination of Fair Value: The valuation techniques and inputs used in NU's fair value measurements are described in Note 4, "Derivative Instruments," Note 5, "Marketable Securities," Note 6, "Asset Retirement Obligations," Note 9A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions," Note 13, "Fair Value of Financial Instruments," and Note 21, "Merger of NU and NSTAR," to the financial statements.

I. Derivative Accounting
Many of the Regulated companies' contracts for the purchase and sale of energy or energy-related products are derivatives. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. For the Regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivative contracts, as contract settlements are recovered from, or refunded to, customers in future rates.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the normal exception, and determination of the fair value of derivative contracts. All of these judgments can have a significant impact on the financial statements.

The judgment applied in the election of the normal exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery of the underlying product and that the quantities will be used or sold by the business in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated, and fair value accounting is applied prospectively.

The fair value of derivative contracts is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the Company determines whether the contract has a determinable quantity by using amounts referenced in default provisions and other relevant sections of the contract. The fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability on the balance sheets. Changes in the fair value of derivative contracts are recorded as regulatory assets or liabilities and do not impact net income.

For further information regarding derivative contracts, see Note 4, "Derivative Instruments," to the financial statements.

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J. Equity Method Investments

Regional Decommissioned Nuclear Companies: CL&P, NSTAR Electric, PSNH and WMECO own common stock in three regional nuclear generation companies (CYAPC, YAEC and MYAPC, collectively referred to as the Yankee Companies), each of which owned a single nuclear generating facility that has been decommissioned. For CL&P, NSTAR Electric, PSNH and WMECO, the respective investments in CYAPC, YAEC and MYAPC are accounted for under the equity method. NU consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's, PSNH's and WMECO's combined ownership interest in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation of the NU financial statements.

Ownership interests in the Yankee Companies as of December 31, 2014 and 2013 were as follows:

(Percent)	CYAPC	YAEC	MYAPC
CL&P	34.5 %	24.5 %	12.0 %
NSTAR Electric	14.0	14.0	4.0
PSNH	5.0	7.0	5.0
WMECO	9.5	7.0	3.0

The total carrying values of CL&P's, NSTAR Electric's, PSNH's and WMECO's ownership interests in CYAPC, YAEC and MYAPC, which are included in Other Long-Term Assets on their respective balance sheets, were as follows:

	As of December 31,	
(Millions of Dollars)	2014	2013
CL&P	$ 1.2	$ 1.2
NSTAR Electric	0.5	0.5
PSNH	0.3	0.3
WMECO	0.3	0.3

For further information on the Yankee Companies, see Note 11C, "Commitments and Contingencies - Contractual Obligations - Yankee Companies," to the financial statements.

Other Investments: As of December 31, 2014 and 2013, NU had an equity ownership interest in an energy investment fund of $17.8 million and $9.8 million, respectively.

Equity investments are included in Other Long-Term Assets on the balance sheets and net earnings related to these equity investments are included in Other Income, Net on the statements of income.

K. Revenues

Regulated Companies: The Regulated companies' retail revenues are based on rates approved by their respective state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. The Regulated companies' rates are designed to recover the costs to provide service to their customers, including a return on investment. The Regulated companies also utilize regulatory commission-approved tracking mechanisms to recover certain costs on a fully-reconciling basis. These tracking mechanisms require rates to be changed periodically to ensure recovery of actual costs incurred. WMECO and CL&P (effective December 1, 2014), each have a revenue decoupling mechanism to recover a pre-established level of baseline distribution delivery service revenues per year, independent of actual customer usage. Decoupling mechanisms effectively break the relationship between sales volumes and revenues recognized.

A significant portion of the Regulated companies' retail revenues relate to the recovery of costs incurred for the sale of electricity and natural gas purchased on behalf of customers. These energy supply costs are recovered from customers in rates through cost tracking mechanisms. Energy purchases are recorded in Purchased Power, Fuel and Transmission, and the sale of energy associated with these purchases are recorded in Operating Revenues.

Regulated Companies' Unbilled Revenues: Because customers are billed throughout the month based on pre-determined cycles rather than on a calendar month basis, an estimate of electricity or natural gas delivered to customers for which the customers have not yet been billed is calculated as of the balance sheet date. Unbilled revenues are included in Operating Revenues on the statements of income and are assets on the balance sheets. Actual amounts billed to customers when meter readings become available may vary from the estimated amount.

The Regulated companies estimate unbilled sales monthly using the daily load cycle method. The daily load cycle method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total month load, net of delivery losses, to estimate unbilled sales. Unbilled revenues are estimated by first allocating unbilled sales to the respective customer classes, then applying an estimated rate by customer class to those sales.

Regulated Companies' Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are recovered through FERC approved formula rates. Wholesale transmission revenues for CL&P, NSTAR Electric, PSNH, and WMECO are collected under the ISO New England Inc. Transmission, Markets and Services Tariff (ISO-NE Tariff). The ISO-NE Tariff includes Regional Network Service (RNS), Schedule 21 - NU rate schedules, which recover the costs of transmission and other transmission-related services for CL&P, PSNH and WMECO, and Schedule 21 - NSTAR rate schedules, which recover costs of transmission and other transmission-related services for NSTAR Electric. The RNS rate, administered by ISO-NE and billed to all New England transmission load, including CL&P, NSTAR Electric, PSNH and WMECO's distribution businesses, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the entire New England region. Schedule 21 - NU and Schedule 21 - NSTAR rates, administered by NU, recovers the remainder of the transmission revenue requirements. The Schedule 21 - NU rate is reset on January 1st and June 1st of each year, while the Schedule 21 - NSTAR rate is reset on June 1st of each year. The Schedule 21 - NU and Schedule 21 - NSTAR rate calculations recover total transmission revenue requirements net of revenues

received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all of CL&P's, NSTAR Electric's, PSNH's and WMECO's regional and local transmission revenue requirements in accordance with the ISO-NE Tariff. RNS, Schedule 21 - NU and Schedule 21 - NSTAR rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refunded to, transmission customers. See Note 11E, "Commitments and Contingencies – FERC Base ROE Complaints," for complaints filed at FERC relating to NU's base ROE.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution businesses of CL&P, NSTAR Electric, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. CL&P, NSTAR Electric, PSNH and WMECO each have a retail transmission cost tracking mechanism as part of their rates, which allows the electric distribution companies to charge their retail customers for transmission costs on a timely basis.

L. Operating Expenses

Costs related to fuel and natural gas included in Purchased Power, Fuel and Transmission on the statements of income were as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012
NU - Natural Gas and Fuel [1]	$ 599.4	$ 466.5	$ 346.8
PSNH – Fuel	113.4	104.8	103.4

[1] NSTAR Gas natural gas costs were included in NU beginning April 10, 2012.

M. Allowance for Funds Used During Construction

AFUDC represents the cost of borrowed and equity funds used to finance construction and is included in the cost of the Regulated companies' utility plant. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Other Interest Expense, and the AFUDC related to equity funds is recorded as Other Income, Net on the statements of income. AFUDC costs are recovered from customers over the service life of the related plant in the form of increased revenue collected as a result of higher depreciation expense.

The Regulated companies' average AFUDC rate is based on a FERC-prescribed formula using the cost of a company's short-term financings and capitalization (preferred stock, long-term debt and common equity), as appropriate. The average rate is applied to average eligible CWIP amounts to calculate AFUDC.

NU	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	2014	2013	2012 [1]
Borrowed Funds	$ 5.8	$ 4.1	$ 5.3
Equity Funds	13.7	7.1	6.8
Total AFUDC	$ 19.5	$ 11.2	$ 12.1
Average AFUDC Rate	3.4%	2.7%	3.7%

[1] NSTAR amounts were included in NU beginning April 10, 2012.

	For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars, except percentages)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Borrowed Funds	$ 1.9	$ 2.0	$ 0.6	$ 0.9	$ 2.2	$ 0.5	$ 0.5	$ 0.5	$ 2.5	$ 0.3	$ 1.6	$ 0.5
Equity Funds	2.9	3.8	0.6	1.7	2.9	-	0.2	1.0	1.9	-	1.9	1.0
Total AFUDC	$ 4.8	$ 5.8	$ 1.2	$ 2.6	$ 5.1	$ 0.5	$ 0.7	$ 1.5	$ 4.4	$ 0.3	$ 3.5	$ 1.5
Average AFUDC Rate	3.4%	2.5%	1.8%	5.6%	3.7%	0.5%	1.1%	6.1%	3.6%	0.4%	5.9%	6.8%

N. Other Income, Net

Items included within Other Income, Net on the statements of income primarily consist of investment income/(loss), interest income, AFUDC related to equity funds, and equity in earnings. Investment income/(loss) primarily relates to debt and equity securities held in trust. For further information, see Note 5, "Marketable Securities," to the financial statements. For further information on AFUDC related to equity funds, see Note 1M, "Summary of Significant Accounting Policies – Allowance for Funds Used During Construction," to the financial statements.

O. Other Taxes

Gross receipts taxes levied by the state of Connecticut are collected by CL&P and Yankee Gas from their respective customers. These gross receipts taxes are shown on a gross basis with collections in Operating Revenues and payments in Taxes Other Than Income Taxes on the statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012
NU	$ 148.2	$ 144.1	$ 135.0
CL&P	127.9	128.2	120.7

Certain sales taxes are collected by NU's companies that serve customers in Connecticut and Massachusetts as agents for state and local governments and are recorded on a net basis with no impact on the statements of income.

P. Supplemental Cash Flow Information

NU	As of and For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012 [(1)]
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 349.6	$ 343.3	$ 356.5
Income Taxes	334.2	50.0	(12.8)
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	181.9	193.1	160.6

(1) NSTAR amounts were included in NU beginning April 10, 2012.

	As of and For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Cash Paid/(Received) During the Year for:												
Interest, Net of Amounts Capitalized	$ 144.1	$ 75.3	$ 41.1	$ 25.9	$ 131.6	$ 75.8	$ 43.3	$ 25.8	$ 129.4	$ 94.6	$ 49.8	$ 25.8
Income Taxes	135.4	217.1	2.3	25.1	55.0	163.4	(30.1)	(69.0)	(42.0)	88.1	14.7	(8.4)
Non-Cash Investing Activities:												
Plant Additions Included in Accounts Payable (As of)	63.5	34.6	39.3	14.2	51.4	57.0	34.9	19.5	42.8	50.0	16.8	30.0

In 2014, as a result of damages awarded to the Yankee Companies for spent nuclear fuel lawsuits against the DOE described in Note 11C, "Commitments and Contingencies - Contractual Obligations - Yankee Companies," NU received total proceeds of $132.1 million, which were net of $80.6 million in proceeds CYAPC and YAEC returned to non-affiliated member companies.

The merger of NU with NSTAR on April 10, 2012 represented a significant non-cash transaction. Refer to Note 21, "Merger of NU and NSTAR," for further information.

Q. Related Parties

NUSCO, NU's service company, provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. The Rocky River Realty Company, Renewable Properties, Inc. and Properties, Inc., three other NU subsidiaries, construct, acquire or lease some of the property and facilities used by NU's companies.

As of both December 31, 2014 and 2013, CL&P, PSNH and WMECO had long-term receivables from NUSCO in the amounts of $25 million, $3.8 million and $5.5 million, respectively, which were included in Other Long-Term Assets on the balance sheets. These amounts related to the funding of investments held in trust by NUSCO in connection with certain postretirement benefits for CL&P, PSNH and WMECO employees and have been eliminated in consolidation on the NU financial statements.

Included in the CL&P, NSTAR Electric, PSNH and WMECO balance sheets as of December 31, 2014 and 2013 were Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, NSTAR Electric, PSNH and WMECO and other subsidiaries that are wholly-owned by NU. These amounts have been eliminated in consolidation on the NU financial statements.

R. Severance Benefits

For the years ended December 31, 2014 and 2013, NU recorded severance benefit expenses of $15 million and $9.7 million, respectively, in connection with the partial outsourcing of information technology functions and facilities closures, as well as ongoing post-merger integration. As of December 31, 2014 and 2013, the severance accrual totaled $10.4 million and $14.7 million, respectively, and was included in Other Current Liabilities on the balance sheets.

2. REGULATORY ACCOUNTING

The rates charged to the customers of NU's Regulated companies are designed to collect each company's costs to provide service, including a return on investment. Therefore, the accounting policies of the Regulated companies follow the application of accounting guidance for entities with rate-regulated operations and reflect the effects of the rate-making process.

Management believes it is probable that each of the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. If management were to determine that it could no longer apply the accounting guidance applicable to rate-regulated enterprises to any of the Regulated companies' operations, or that management could not conclude it is probable that costs would be recovered from customers in future rates, the costs would be charged to net income in the period in which the determination is made.

Regulatory Assets: The components of regulatory assets are as follows:

NU (Millions of Dollars)	As of December 31, 2014	2013
Benefit Costs	$ 2,016.0	$ 1,240.2
Derivative Liabilities	425.5	638.0
Income Taxes, Net	635.3	626.2
Storm Restoration Costs	502.8	589.6
Goodwill-related	505.4	525.9
Regulatory Tracker Mechanisms	350.5	323.4
Contractual Obligations - Yankee Companies	123.8	154.2
Buy Out Agreements for Power Contracts	42.6	70.2
Other Regulatory Assets	124.7	126.8
Total Regulatory Assets	4,726.6	4,294.5
Less: Current Portion	672.5	535.8
Total Long-Term Regulatory Assets	$ 4,054.1	$ 3,758.7

	As of December 31, 2014				2013			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Benefit Costs	$ 445.4	$ 515.9	$ 174.3	$ 85.0	$ 297.7	$ 496.7	$ 100.6	$ 57.3
Derivative Liabilities	410.9	4.5	-	-	630.4	7.7	-	-
Income Taxes, Net	437.7	83.7	38.0	35.5	415.5	84.0	40.3	43.7
Storm Restoration Costs	319.6	103.7	47.7	31.8	397.8	109.3	43.7	38.8
Goodwill-related	-	433.9	-	-	-	451.5	-	-
Regulatory Tracker Mechanisms	16.1	141.4	103.5	33.0	8.0	169.5	83.3	32.6
Buy Out Agreements for Power Contracts	-	38.6	4.0	-	-	64.7	5.5	-
Other Regulatory Assets	66.1	56.1	37.3	12.9	64.6	55.9	38.1	16.7
Total Regulatory Assets	1,695.8	1,377.8	404.8	198.2	1,814.0	1,439.3	311.5	189.1
Less: Current Portion	220.3	198.7	111.7	51.9	150.9	204.1	92.2	43.0
Total Long-Term Regulatory Assets	$ 1,475.5	$ 1,179.1	$ 293.1	$ 146.3	$ 1,663.1	$ 1,235.2	$ 219.3	$ 146.1

Regulatory Costs in Other Long-Term Assets: The Regulated companies had $60.5 million ($1.3 million for CL&P, $33.2 million for NSTAR Electric, $0.9 million for PSNH, and $11 million for WMECO) and $65.1 million ($7.3 million for CL&P, $33.4 million for NSTAR Electric, and $10.1 million for WMECO) of additional regulatory costs as of December 31, 2014 and 2013, respectively, that were included in Other Long-Term Assets on the balance sheets. These amounts represent incurred costs for which recovery has not yet been specifically approved by the applicable regulatory agency. However, based on regulatory policies or past precedent on similar costs, management believes it is probable that these costs will ultimately be approved and recovered from customers in rates. The NSTAR Electric balance as of December 31, 2014 and 2013 primarily related to costs deferred in connection with the basic service bad debt adder. See Note 11G, "Commitments and Contingencies – Basic Service Bad Debt Adder," for further information.

Equity Return on Regulatory Assets: For rate-making purposes, the Regulated companies recover the carrying costs related to their regulatory assets. For certain regulatory assets, the carrying cost recovered includes an equity return component. This equity return, which is not recorded on the balance sheets, totaled $1.7 million and $1.9 million for CL&P and $43.3 million and $33.1 million for PSNH as of December 31, 2014 and 2013, respectively. These carrying costs will be recovered from customers in future rates.

Regulatory Assets - The following provides further information about regulatory assets:

Benefit Costs: NU's Pension, SERP and PBOP Plans are accounted for in accordance with accounting guidance on defined benefit pension and other PBOP plans. The liability recorded by the Regulated companies to recognize the funded status of their retiree benefit plans are offset by regulatory assets in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates. All amounts are remeasured annually. Regulatory accounting was also applied to the portions of NU's service company costs that support the Regulated companies, as these amounts are also recoverable. As these regulatory assets do not represent a cash outlay for the Regulated companies, no carrying charge is recovered from customers.

The increase in the funded status liability of the retiree benefit plans and the corresponding regulatory assets was primarily driven by a change in mortality assumptions, which increased the estimate of benefits to be provided to plan participants, and a decrease in the discount rate assumption. For further information on the funded status liability and related regulatory assets of the Pension, SERP and PBOP plans, see Note 9A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions."

CL&P, NSTAR Electric, PSNH and WMECO recover benefit costs related to their distribution and transmission operations from customers in rates as allowed by their applicable regulatory commissions. NSTAR Electric and WMECO each recover their qualified pension and PBOP expenses related to distribution operations through rate reconciling mechanisms that fully track the change in net pension and PBOP expenses each year.

Derivative Liabilities: Regulatory assets recorded as an offset to derivative liabilities relate to the fair value of contracts used to purchase energy and energy-related products that will be recovered from customers in future rates. See Note 4, "Derivative Instruments," to the financial statements for further information. These assets are excluded from rate base and are being recovered as the actual settlements occur over the duration of the contracts.

Income Taxes, Net: The tax effect of temporary book-tax differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. As these assets are offset by deferred income tax liabilities, no carrying charge is collected. For further information regarding income taxes, see Note 10, "Income Taxes," to the financial statements.

Storm Restoration Costs: The storm restoration cost deferrals relate to costs incurred at CL&P, NSTAR Electric, PSNH and WMECO that each company expects to recover from customers. A storm must meet certain criteria to be declared a major storm with the criteria specific to each state jurisdiction and utility company. Once a storm is declared major, all qualifying expenses incurred during storm restoration efforts are deferred and recovered from customers. In addition to storm restoration costs, CL&P and PSNH are each allowed to recover storm pre-staging costs in accordance with applicable regulation.

CL&P, NSTAR Electric, PSNH and WMECO experienced several significant storm events, including Tropical Storm Irene in 2011, the October 2011 snowstorm, Storm Sandy in 2012 and the February 2013 blizzard. As a result of these storm events, each company suffered extensive damage to its distribution and transmission systems resulting in customer outages. Each company incurred significant costs to repair damage and restore customers' service. In addition, on November 26, 2014, a snowstorm caused damage to the electric delivery systems of PSNH and WMECO. This snowstorm resulted in estimated deferred storm restoration costs of approximately $23 million at PSNH and approximately $3 million at WMECO. The storm restoration cost regulatory asset balance at CL&P, NSTAR Electric, PSNH and WMECO reflects deferrable costs incurred for major storm events. Management believes the storm restoration costs were prudent and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery process.

Storm Filings: Each electric utility has sought, or is seeking, recovery of its deferred storm restoration costs through its applicable regulatory recovery process.

CL&P: As of December 31, 2014, all CL&P deferred storm costs have been reviewed and approved for recovery in distribution rates. On March 12, 2014, the PURA approved recovery of $365 million of deferred storm restoration costs (with carrying charges) associated with five major storms that occurred in 2011 and 2012 and ordered CL&P to capitalize approximately $18 million of the deferred storm restoration costs as utility plant, which will be recovered through depreciation expense in future rate proceedings. CL&P will recover the $365 million in its distribution rates over a six-year period that commenced on December 1, 2014. The remaining costs were either disallowed or are probable of recovery from other sources. These costs did not have a material impact on CL&P's financial position, results of operations or cash flows.

Effective June 1, 2014, CL&P received $65.4 million of DOE Phase II Damages proceeds. On June 17, 2014, the PURA ordered CL&P to refund these proceeds to customers by offsetting the deferred storm restoration costs regulatory asset. For further information on the DOE Phase II Damages proceeds received from the Yankee Companies, see Note 11C, "Commitments and Contingencies - Contractual Obligations - Yankee Companies," to the financial statements.

On December 17, 2014, as part of the distribution rate case decision, CL&P was also allowed recovery of the 2013 storm costs and residual 2012 Storm Sandy costs over a seven-year period that commenced on December 1, 2014.

NSTAR Electric: On December 30, 2013, the DPU approved recovery of $34.2 million of NSTAR Electric's storm restoration costs, plus carrying costs, related to Tropical Storm Irene in 2011 and the October 2011 snowstorm. NSTAR Electric is recovering these costs, plus carrying costs, in its distribution rates over a five-year period that commenced on January 1, 2014.

PSNH: On June 27, 2013, the NHPUC approved an increase to PSNH's distribution rates effective July 1, 2013, which included a $5 million increase to the level of funding for the major storm cost reserve. The major storm cost reserve is used to offset the storm restoration cost regulatory asset. On April 7, 2014, PSNH received an audit report from the NHPUC approving storm costs from 2011 through March 2013.

WMECO: On December 20, 2013, the DPU approved WMECO's 2013 Annual Storm Reserve Recovery Cost Adjustment filing to begin recovering the October 2011 snowstorm and 2012 Storm Sandy restoration costs, which commenced on January 1, 2014, subject to further review and reconciliation. On December 5, 2014, the DPU approved the majority of deferred storm costs through 2011.

Goodwill-related: The goodwill regulatory asset originated from the transaction that created NSTAR in 1999. This regulatory asset is currently being amortized and recovered from customers in rates without a carrying charge over a 40-year period (as of December 31, 2014, there were 25 years of amortization remaining).

Regulatory Tracker Mechanisms: The Regulated companies' approved rates are designed to recover their incurred costs to provide service to customers. The Regulated companies recover certain of their costs on a fully-reconciling basis through regulatory commission-approved tracking mechanisms. The difference between the costs incurred (or the rate recovery allowed) and the actual revenues is recorded as regulatory assets (for undercollections) or regulatory liabilities (for overcollections) to be included in future customer rates each year. Carrying charges are recorded on all material regulatory tracker mechanisms.

CL&P, NSTAR Electric, PSNH and WMECO each recover the costs associated with the procurement of energy, transmission related costs from FERC-approved transmission tariffs, energy efficiency programs, low income assistance programs, and restructuring and stranded costs as a result of deregulation, on a fully reconciling basis. Energy procurement costs at PSNH include the costs related to its generating stations.

WMECO's and CL&P's (effective December 1, 2014) distribution revenue is decoupled from their customer sales volume. CL&P and WMECO reconcile their annual base distribution rate recovery to a pre-established level of baseline distribution delivery service revenue. Any difference

between the allowed level of distribution revenue and the actual amount incurred during a 12-month period is adjusted through rates in the following period.

Contractual Obligations - Yankee Companies: CL&P, NSTAR Electric, PSNH and WMECO are responsible for their proportionate share of the remaining costs of the CYAPC, YAEC and MYAPC nuclear facilities, including nuclear fuel storage. A portion of these amounts was recorded as a regulatory asset. Amounts for CL&P are earning a return and are being recovered through the CTA. Amounts for NSTAR Electric and WMECO are being recovered without a return through the transition charge. Amounts for PSNH were fully recovered in 2006. As a result of NU's consolidation of CYAPC and YAEC, NU's regulatory asset balance also includes the regulatory assets of CYAPC and YAEC, which totaled $97.8 million and $129.8 million as of December 31, 2014 and 2013, respectively. Intercompany transactions between CL&P, NSTAR Electric, PSNH and WMECO and the CYAPC and YAEC companies have been eliminated in consolidation of the NU financial statements.

Buy Out Agreements for Power Contracts: NSTAR Electric's balance represents the contract termination liability related to certain purchase power contract buy out agreements that were executed in 2004. The contracts' termination payments occur through September 2016 and are collected from customers through NSTAR Electric's transition charge over the same period. NSTAR Electric does not earn a return on this regulatory asset. PSNH's balance represents payments associated with the termination of various power purchase contracts that were recorded as regulatory assets and are amortized over the remaining life of the contracts.

Other Regulatory Assets: Other Regulatory Assets primarily include asset retirement obligations, environmental remediation costs, losses associated with the reacquisition or redemption of long-term debt and various other items, partially offset by purchase price adjustments recorded as Regulatory Assets in connection with the merger with NSTAR.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

NU	As of December 31,	
(Millions of Dollars)	2014	2013
Cost of Removal	$ 439.9	$ 435.1
Regulatory Tracker Mechanisms	192.3	151.2
AFUDC - Transmission	67.1	68.1
Other Regulatory Liabilities	50.8	52.9
Total Regulatory Liabilities	750.1	707.3
Less: Current Portion	235.0	204.3
Total Long-Term Regulatory Liabilities	$ 515.1	$ 503.0

	As of December 31,							
	2014				2013			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Cost of Removal	$ 19.7	$ 258.3	$ 50.3	$ 1.1	$ 29.1	$ 250.0	$ 49.7	$ -
Regulatory Tracker Mechanisms	122.6	20.7	14.2	22.3	95.6	21.9	21.6	21.1
AFUDC – Transmission	53.6	4.4	-	9.1	54.7	4.1	-	9.3
Other Regulatory Liabilities	10.1	28.9	2.9	0.8	8.4	31.1	1.0	3.4
Total Regulatory Liabilities	206.0	312.3	67.4	33.3	187.8	307.1	72.3	33.8
Less: Current Portion	124.7	49.6	16.0	22.5	94.0	54.0	20.6	19.9
Total Long-Term Regulatory Liabilities	$ 81.3	$ 262.7	$ 51.4	$ 10.8	$ 93.8	$ 253.1	$ 51.7	$ 13.9

Cost of Removal: NU's Regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. The estimated cost to remove utility assets from service is recognized as a component of depreciation expense and the cumulative amounts collected from customers but not yet expended is recognized as a regulatory liability. Expended costs that exceed amounts collected from customers are recognized as regulatory assets, as they are probable of recovery in future rates.

AFUDC - Transmission: AFUDC was recorded by CL&P and WMECO for their NEEWS projects through May 31, 2011, all of which was reserved as a regulatory liability to reflect rate base recovery for 100 percent of the CWIP as a result of FERC-approved transmission incentives. Effective June 1, 2011, FERC approved changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base. As a result, CL&P and WMECO no longer record AFUDC on NEEWS CWIP. NSTAR Electric recorded AFUDC on reliability-related projects over $5 million through December 31, 2014, 50 percent of which was recorded as a regulatory liability to reflect rate base recovery for 50 percent of the CWIP as a result of FERC-approved transmission incentives.

Other Regulatory Liabilities: Other Regulatory Liabilities primarily includes amounts that are subject to various rate reconciling mechanisms that, as of each period end date, would result in refunds to customers.

2014 Regulatory Developments: As a result of actions taken by the FERC and other developments in the pending base ROE complaint proceedings described in Note 11E, "Commitments and Contingencies – FERC Base ROE Complaints," in 2014 the Company recorded reserves at its electric subsidiaries to recognize the potential financial impact of the first and second complaints. As of December 31, 2014, the cumulative pre-tax reserves (excluding interest), which exclude refunds for the first complaint refund period, totaled $60.7 million at NU, $33.5 million at CL&P, $13.6 million at NSTAR Electric, $5.1 million at PSNH and $8.5 million at WMECO. As of December 31, 2013, as a result of the 2013 FERC ALJ initial decision, the Company had an aggregate pre-tax reserve (excluding interest) of $23.7 million at NU, $12.8 million at CL&P, $5.7 million at NSTAR Electric, $2.3 million at PSNH and $2.9 million at WMECO. These reserves were recorded as a regulatory liability in Regulatory Tracker Mechanisms and as a reduction of Operating Revenues.

Effective June 1, 2014, as a result of damages awarded to the Yankee Companies for spent nuclear fuel lawsuits against the DOE described in Note 11C, "Commitments and Contingencies - Contractual Obligations - Yankee Companies," the Yankee Companies returned the DOE Phase II Damages proceeds to the member companies, including CL&P, NSTAR Electric, PSNH, and WMECO, for the benefit of their respective customers. CL&P's refund obligation to customers of $65.4 million was recorded as an offset to the deferred storm restoration costs regulatory asset, as directed by PURA. NSTAR Electric's, PSNH's and WMECO's refund obligation to customers of $29.1 million, $13.1 million and $18.1 million, respectively, was recorded as a regulatory liability in Regulatory Tracker Mechanisms. Refunds to customers for these DOE proceeds began in 2014.

On December 31, 2014, NSTAR Electric, NSTAR Gas and the Massachusetts Attorney General filed a comprehensive settlement agreement with the DPU. The comprehensive settlement agreement included resolution of the outstanding NSTAR Electric CPSL program filings for the periods 2006 through 2011, the NSTAR Electric and NSTAR Gas PAM and energy efficiency-related customer billing adjustments reported in 2012, and the NSTAR Electric energy efficiency program filings regarding LBR for the periods 2008 through 2011. If approved by the DPU, NSTAR Electric and NSTAR Gas will be required to refund a total of $44.7 million to their respective customers, which was included in Regulatory Tracker Mechanisms and Other Regulatory Liabilities as of December 31, 2014. For further information, see Note 11F, "Commitments and Contingencies – 2014 Comprehensive Settlement Agreement."

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Utility property, plant and equipment is recorded at original cost. Original cost includes materials, labor, construction overhead and AFUDC for regulated property. The cost of repairs and maintenance, including planned major maintenance activities, is charged to Operating Expenses as incurred.

The following tables summarize the investments in utility property, plant and equipment by asset category:

NU	As of December 31,	
(Millions of Dollars)	2014	2013
Distribution - Electric	$ 12,495.2	$ 11,950.2
Distribution - Natural Gas	2,595.4	2,425.9
Transmission	6,930.7	6,412.5
Generation	1,170.9	1,152.3
Electric and Natural Gas Utility	23,192.2	21,940.9
Other [(1)]	551.3	508.7
Property, Plant and Equipment, Gross	23,743.5	22,449.6
Less: Accumulated Depreciation		
Electric and Natural Gas Utility	(5,777.8)	(5,387.0)
Other	(231.8)	(196.2)
Total Accumulated Depreciation	(6,009.6)	(5,583.2)
Property, Plant and Equipment, Net	17,733.9	16,866.4
Construction Work in Progress	913.1	709.8
Total Property, Plant and Equipment, Net	$ 18,647.0	$ 17,576.2

[(1)] These assets are primarily comprised of building improvements, computer software, hardware and equipment and telecommunications assets at NU's service company and unregulated companies.

	As of December 31,							
	2014				2013			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Distribution	$ 5,158.8	$ 4,895.5	$ 1,696.7	$ 784.2	$ 4,930.7	$ 4,694.7	$ 1,608.2	$ 756.6
Transmission	3,274.0	1,928.5	789.7	891.0	3,071.9	1,772.3	695.7	826.4
Generation	-	-	1,136.5	34.4	-	-	1,131.2	21.1
Property, Plant and Equipment, Gross	8,432.8	6,824.0	3,622.9	1,709.6	8,002.6	6,467.0	3,435.1	1,604.1
Less: Accumulated Depreciation	(1,928.0)	(1,761.4)	(1,090.0)	(297.4)	(1,804.1)	(1,631.3)	(1,021.8)	(271.5)
Property, Plant and Equipment, Net	6,504.8	5,062.6	2,532.9	1,412.2	6,198.5	4,835.7	2,413.3	1,332.6
Construction Work in Progress	304.9	272.8	102.9	49.1	252.8	208.2	54.3	48.5
Total Property, Plant and Equipment, Net	$ 6,809.7	$ 5,335.4	$ 2,635.8	$ 1,461.3	$ 6,451.3	$ 5,043.9	$ 2,467.6	$ 1,381.1

Depreciation of utility assets is calculated on a straight-line basis using composite rates based on the estimated remaining useful lives of the various classes of property (estimated useful life for PSNH distribution). The composite rates are subject to approval by the appropriate state regulatory agency. The composite rates include a cost of removal component, which is collected from customers over the lives of the plant assets and is recognized as a regulatory liability. Depreciation rates are applied to property from the time it is placed in service.

Upon retirement from service, the cost of the utility asset is charged to the accumulated provision for depreciation. The actual incurred removal costs are applied against the related regulatory liability.

The depreciation rates for the various classes of utility property, plant and equipment aggregate to composite rates as follows:

(Percent)	2014	2013	2012
NU	3.0 %	2.8 %	2.5 %
CL&P	2.7	2.5	2.5
NSTAR Electric	3.0	2.9	2.8
PSNH	3.0	3.0	3.0
WMECO	3.3	2.9	3.3

The following table summarizes average useful lives of depreciable assets:

	Average Depreciable Life				
(Years)	NU	CL&P	NSTAR Electric	PSNH	WMECO
Distribution	34.9	37.5	32.3	32.3	30.9
Transmission	42.5	39.8	44.0	43.7	49.9
Generation	31.9	-	-	32.1	25.0
Other	14.2	-	-	-	-

4. DERIVATIVE INSTRUMENTS

The Regulated companies purchase and procure energy and energy-related products, which are subject to price volatility, for their customers. The costs associated with supplying energy to customers are recoverable through customer rates. The Regulated companies manage the risks associated with the price volatility of energy and energy-related products through the use of derivative and nonderivative contracts.

Many of the derivative contracts meet the definition of, and are designated as, normal and qualify for accrual accounting under the applicable accounting guidance. The costs and benefits of derivative contracts that meet the definition of normal are recognized in Operating Expenses or Operating Revenues on the statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not designated as normal are recorded at fair value as current or long-term Derivative Assets or Derivative Liabilities on the balance sheets. For the Regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivatives, as contract settlements are recovered from, or refunded to, customers in their respective energy supply rates. For NU's unregulated wholesale marketing contracts that expired on December 31, 2013, changes in fair values of derivatives were included in Net Income.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, on the balance sheets. The following table presents the gross fair values of contracts categorized by risk type and the net amount recorded as current or long-term derivative asset or liability:

	As of December 31,					
	2014			2013		
(Millions of Dollars)	Commodity Supply and Price Risk Management	Netting [(1)]	Net Amount Recorded as a Derivative	Commodity Supply and Price Risk Management	Netting [(1)]	Net Amount Recorded as a Derivative
Current Derivative Assets:						
Level 2:						
NU	$ -	$ -	$ -	$ 1.9	$ (0.3)	$ 1.6
Level 3:						
NU	16.2	(6.6)	9.6	18.4	(9.8)	8.6
CL&P	16.1	(6.6)	9.5	17.1	(9.8)	7.3
NSTAR Electric	0.1	-	0.1	1.2	-	1.2
Long-Term Derivative Assets:						
Level 2:						
NU	$ -	$ -	$ -	$ 0.2	$ -	$ 0.2
Level 3:						
NU	93.5	(19.2)	74.3	116.2	(42.2)	74.0
CL&P	93.5	(19.2)	74.3	113.6	(42.2)	71.4
Current Derivative Liabilities:						
Level 2:						
NU	$ (9.8)	$ -	$ (9.8)	$ -	$ -	$ -
Level 3:						
NU	(90.0)	-	(90.0)	(93.7)	-	(93.7)
CL&P	(88.5)	-	(88.5)	(92.2)	-	(92.2)
NSTAR Electric	(1.5)	-	(1.5)	(1.5)	-	(1.5)
Level 2:						
NU	$ (0.3)	$ -	$ (0.3)	$ -	$ -	$ -
Level 3:						
NU	(409.3)	-	(409.3)	(624.1)	-	(624.1)
CL&P	(406.2)	-	(406.2)	(617.1)	-	(617.1)
NSTAR Electric	(3.1)	-	(3.1)	(7.0)	-	(7.0)

DERIVATIVE INSTRUMENTS

(1) Amounts represent derivative assets and liabilities that NU elected to record net on the balance sheets. These amounts are subject to master netting agreements or similar agreements for which the right of offset exists.

The business activities that result in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2014, NU and CL&P's derivative assets were exposed to counterparty credit risk. Of NU's and CL&P's derivative assets, $64 million was contracted with investment grade entities.

For further information on the fair value of derivative contracts, see Note 1H, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 1I, "Summary of Significant Accounting Policies - Derivative Accounting," to the financial statements.

Derivative Contracts At Fair Value with Offsetting Regulatory Amounts

Commodity Supply and Price Risk Management: As required by regulation, CL&P, along with UI, has capacity-related contracts with generation facilities. CL&P has a sharing agreement with UI, with 80 percent of each contract allocated to CL&P and 20 percent allocated to UI. The combined capacity of these contracts is 787 MW. The capacity contracts extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the capacity market price received in the ISO-NE capacity markets. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

NSTAR Electric has a renewable energy contract to purchase 0.1 million MWh of energy per year through 2018 and a capacity-related contract to purchase up to 35 MW per year through 2019.

As of December 31, 2014 and 2013, NU had NYMEX future contracts in order to reduce variability associated with the purchase price of approximately 8.8 million and 9.1 million MMBtu of natural gas, respectively.

The following table presents the current change in fair value, primarily recovered through rates from customers, associated with NU's derivative contracts:

(Millions of Dollars)	Gain/(Loss) Recognized on Derivatives For the Years Ended December 31,		
NU	2014	2013	2012
Balance Sheets:			
Regulatory Assets and Liabilities	$ 134.4	$ 160.6	$ (29.0)
Statements of Income:			
Purchased Power, Fuel and Transmission	-	1.0	(0.7)

Credit Risk

Certain of NU's derivative contracts contain credit risk contingent features. These features require NU to maintain investment grade credit ratings from the major rating agencies and to post collateral for contracts in a net liability position over specified credit limits. As of December 31, 2014, NU had approximately $10 million of derivative contracts in a net liability position that were subject to credit risk contingent features and would have been required to post additional collateral of approximately $10 million if NU parent's unsecured debt credit ratings had been downgraded to below investment grade. As of December 31, 2013, there were no derivative contracts in a net liability position that were subject to credit risk contingent features.

Fair Value Measurements of Derivative Instruments

Derivative contracts classified as Level 2 in the fair value hierarchy relate to the financial contracts for natural gas futures. Prices are obtained from broker quotes and are based on actual market activity. The contracts are valued using NYMEX natural gas prices. Valuations of these contracts also incorporate discount rates using the yield curve approach.

The fair value of derivative contracts classified as Level 3 utilizes significant unobservable inputs. The fair value is modeled using income techniques, such as discounted cash flow valuations adjusted for assumptions relating to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices in future years for which quoted prices in an active market exist. Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The future power and capacity prices for periods that are not quoted in an active market or established at auction are based on available market data and are escalated based on estimates of inflation to address the full time period of the contract.

Valuations of derivative contracts using a discounted cash flow methodology include assumptions regarding the timing and likelihood of scheduled payments and also reflect non-performance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the Company's credit rating for liabilities. Valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using historical market transactions adjusted for the terms of the contract.

The following is a summary of NU's, including CL&P's and NSTAR Electric's, Level 3 derivative contracts and the range of the significant unobservable inputs utilized in the valuations over the duration of the contracts:

	As of December 31,					
	2014			2013		
	Range		Period Covered	Range		Period Covered
Energy Prices:						
NU	$ 52	per MWh	2020	$ 49 - 77	per MWh	2018 - 2029
CL&P	$ 52	per MWh	2020	$ 56 - 58	per MWh	2018 - 2029
Capacity Prices:						
NU	$ 5.30 - 12.98	per kW-Month	2016 - 2026	$ 5.07 - 11.82	per kW-Month	2017 - 2029
CL&P	$ 11.08 - 12.98	per kW-Month	2018 - 2026	$ 5.07 - 10.42	per kW-Month	2017 - 2026
NSTAR Electric	$ 5.30 - 11.10	per kW-Month	2016 - 2019	$ 5.07 - 7.38	per kW-Month	2017 - 2019
Forward Reserve:						
NU, CL&P	$ 5.80 - 9.50	per kW-Month	2015 - 2024	$ 3.30	per kW-Month	2014 - 2024
REC Prices:						
NU	$ 38 - 56	per REC	2015 - 2018	$ 36 - 87	per REC	2014 - 2029
NSTAR Electric	$ 38 - 56	per REC	2015 - 2018	$ 36 - 70	per REC	2014 - 2018

Exit price premiums of 7 percent through 24 percent are also applied on these contracts and reflect the most recent market activity available for similar type contracts.

Significant increases or decreases in future energy or capacity prices in isolation would decrease or increase, respectively, the fair value of the derivative liability. Any increases in the risk premiums would increase the fair value of the derivative liabilities. Changes in these fair values are recorded as a regulatory asset or liability and would not impact net income.

Valuations using significant unobservable inputs: The following tables present changes in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis.

(Millions of Dollars)	NU	CL&P	NSTAR Electric
Derivatives, Net:			
Fair Value as of January 1, 2013	$ (878.6)	$ (866.2)	$ (14.9)
Net Realized/Unrealized Gains Included in:			
Net Income [(1)]	10.9	-	-
Regulatory Assets and Liabilities	158.3	148.9	3.5
Settlements	74.2	86.7	4.1
Fair Value as of December 31, 2013	$ (635.2)	$ (630.6)	$ (7.3)
Net Realized/Unrealized Gains Included in Regulatory Assets and Liabilities	141.3	139.7	4.3
Settlements	78.5	80.0	(1.5)
Fair Value as of December 31, 2014	$ (415.4)	$ (410.9)	$ (4.5)

(1) The Net Income impact for the year ended December 31, 2013 related to the unregulated wholesale marketing sales contract that was offset by the losses on the unregulated sourcing contracts classified as Level 2 in the fair value hierarchy, resulting in a total net gain of $1 million.

5. MARKETABLE SECURITIES

NU maintains trusts to fund certain non-qualified executive benefits and WMECO maintains a spent nuclear fuel trust to fund WMECO's prior period spent nuclear fuel liability. These trusts hold marketable securities. These trusts are not subject to regulatory oversight by state or federal agencies. In addition, CYAPC and YAEC maintain legally restricted trusts, each of which holds marketable securities, for settling the decommissioning obligations of their nuclear power plants.

The Company elected to record mutual funds at fair value and certain other equity investments as trading securities, with the changes in fair values recorded in Other Income, Net on the statements of income. As of December 31, 2014 and 2013, the mutual funds and equity investments were classified as Level 1 in the fair value hierarchy and totaled $85.1 million and $57.2 million, respectively. For the years ended December 31, 2014, 2013 and 2012, net gains on these securities of $1.9 million, $10.2 million and $5.9 million, respectively, were recorded in Other Income, Net on the statements of income. Dividend income is recorded in Other Income, Net when dividends are declared. All other marketable securities are accounted for as available-for-sale.

Available-for-Sale Securities: The following is a summary of NU's and WMECO's available-for-sale securities. These securities are recorded at fair value and are included in current and long-term Marketable Securities on the balance sheets.

	As of December 31,							
	2014				2013			
(Millions of Dollars)	Amortized Cost	Pre-Tax Unrealized Gains	Pre-Tax Unrealized Losses	Fair Value	Amortized Cost	Pre-Tax Unrealized Gains	Pre-Tax Unrealized Losses	Fair Value
NU								
Debt Securities [(1)]	$ 313.0	$ 7.5	$ (0.3)	$ 320.2	$ 299.2	$ 2.5	$ (2.1)	$ 299.6
Equity Securities [(1)]	160.6	73.3	-	233.9	163.6	60.5	-	224.1
WMECO								
Debt Securities [(2)]	58.2	-	(0.1)	58.1	57.9	-	-	57.9

(1) NU's amounts include CYAPC's and YAEC's marketable securities held in nuclear decommissioning trusts of $450.8 million and $424 million as of December 31, 2014 and 2013, respectively, which are legally restricted and can only be used for the costs of decommissioning of the nuclear power plants owned by these companies. Unrealized gains and losses for the nuclear decommissioning trusts are recorded in Marketable Securities with the corresponding offset to Other Long-Term Liabilities on the balance sheets, with no impact on the statements of income. All of the equity securities accounted for as available-for-sale securities are held in the CYAPC and YAEC trusts.

(2) Unrealized gains and losses on debt securities held by WMECO are recorded in Marketable Securities with the corresponding offset to Other Long-Term Assets on the balance sheets.

Unrealized Losses and Other-than-Temporary Impairment: There have been no significant unrealized losses, other-than-temporary impairments or credit losses for NU or WMECO. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset-backed debt securities, underlying collateral and expected future cash flows are also evaluated.

Realized Gains and Losses: Realized gains and losses on available-for-sale securities are recorded in Other Income, Net for NU's benefit trust, Other Long-Term Assets for WMECO, and offset in Other Long-Term Liabilities for CYAPC and YAEC. NU utilizes the specific identification basis method for the NU benefit trust and the average cost basis method for the WMECO trust and the CYAPC and YAEC nuclear decommissioning trusts to compute the realized gains and losses on the sale of available-for-sale securities.

Contractual Maturities: As of December 31, 2014, the contractual maturities of available-for-sale debt securities are as follows:

	NU		WMECO	
(Millions of Dollars)	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Less than one year [(1)]	$ 55.0	$ 55.0	$ 28.7	$ 28.7
One to five years	88.8	89.1	25.8	25.8
Six to ten years	66.0	67.7	0.7	0.7
Greater than ten years	103.2	108.4	3.0	2.9
Total Debt Securities	$ 313.0	$ 320.2	$ 58.2	$ 58.1

(1) Amounts in the Less than one year NU category include securities in the CYAPC and YAEC nuclear decommissioning trusts, which are restricted and are classified in long-term Marketable Securities on the balance sheets.

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	NU		WMECO	
	As of December 31,		As of December 31,	
(Millions of Dollars)	2014	2013	2014	2013
Level 1:				
Mutual Funds and Equities	$ 319.0	$ 281.3	$ -	$ -
Money Market Funds	24.9	32.9	4.3	10.9
Total Level 1	$ 343.9	$ 314.2	$ 4.3	$ 10.9
Level 2:				
U.S. Government Issued Debt Securities (Agency and Treasury)	$ 51.3	$ 61.4	$ -	$ 6.8
Corporate Debt Securities	49.1	53.6	14.7	15.1
Asset-Backed Debt Securities	54.1	30.4	14.5	9.0
Municipal Bonds	116.3	105.5	13.0	11.2
Other Fixed Income Securities	24.5	15.8	11.6	4.9
Total Level 2	$ 295.3	$ 266.7	$ 53.8	$ 47.0
Total Marketable Securities	$ 639.2	$ 580.9	$ 58.1	$ 57.9

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instrument and also incorporating yield curves, credit spreads and specific bond terms and conditions. Asset-backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset-backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and

maturity dates, and tranche information. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6. ASSET RETIREMENT OBLIGATIONS

NU, including CL&P, NSTAR Electric, PSNH and WMECO, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. Settlement dates and future costs are reasonably estimated when sufficient information becomes available. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination and has performed fair value calculations, reflecting expected probabilities for settlement scenarios.

The fair value of an ARO is recorded as a liability in Other Long-Term Liabilities with a corresponding amount included in Property, Plant and Equipment, Net on the balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. As the Regulated companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and both the depreciation and accretion costs associated with the Regulated companies' AROs are recorded as increases to Regulatory Assets on the balance sheets.

A reconciliation of the beginning and ending carrying amounts of ARO liabilities are as follows:

NU	As of December 31,	
(Millions of Dollars)	2014	2013
Balance as of Beginning of Year	$ 424.9	$ 412.2
Liabilities Incurred During the Year	1.3	0.1
Liabilities Settled During the Year	(19.5)	(13.8)
Accretion	25.1	23.8
Revisions in Estimated Cash Flows	(5.5)	2.6
Balance as of End of Year	$ 426.3	$ 424.9

	As of December 31,							
	2014				2013			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Balance as of Beginning of Year	$ 35.0	$ 32.8	$ 19.5	$ 4.5	$ 33.6	$ 31.4	$ 18.4	$ 4.3
Liabilities Incurred During the Year	-	-	-	1.1	-	-	-	-
Liabilities Settled During the Year	(1.1)	-	-	-	(0.7)	(0.1)	-	-
Accretion	1.9	1.5	1.1	0.3	2.2	1.5	1.2	0.3
Revisions in Estimated Cash Flows	(0.5)	-	-	-	(0.1)	-	(0.1)	(0.1)
Balance as of End of Year	$ 35.3	$ 34.3	$ 20.6	$ 5.9	$ 35.0	$ 32.8	$ 19.5	$ 4.5

NU's amounts include CYAPC and YAEC's AROs of $317.3 million and $318.8 million as of December 31, 2014 and 2013, respectively. The fair value of the ARO for CYAPC and YAEC includes uncertainties of the fuel off-load dates related to the DOE's timing of performance regarding its obligation to dispose of the spent nuclear fuel and high level waste. The incremental asset recorded as an offset to the ARO liability was fully depreciated since the plants have no remaining useful life. Any changes in the assumptions used to calculate the fair value of the ARO liability are recorded with a corresponding offset to the related regulatory asset. The assets held in the CYAPC and YAEC nuclear decommissioning trusts are restricted for settling the ARO and all other decommissioning obligations. For further information on the assets held in the nuclear decommissioning trusts, see Note 5, "Marketable Securities," to the financial statements.

7. SHORT-TERM DEBT

Short-Term Borrowing Limits: The amount of short-term borrowings that may be incurred by CL&P, NSTAR Electric and WMECO is subject to periodic approval by the FERC. As a result of the NHPUC having jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On July 31, 2013, the FERC granted authorization to allow CL&P and WMECO to incur total short-term borrowings up to a maximum of $600 million and $300 million, respectively, effective January 1, 2014 through December 31, 2015. On June 11, 2014, the FERC granted authorization to allow NSTAR Electric to issue total short-term debt securities in an aggregate principal amount not to exceed $655 million outstanding at any one time, effective October 24, 2014 through October 23, 2016.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2014, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled approximately $306 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. As of December 31, 2014, CL&P had $432.1 million of unsecured debt capacity available under this authorization.

Yankee Gas and NSTAR Gas are not required to obtain approval from any state or federal authority to incur short-term debt.

Credit Agreements and Commercial Paper Programs: NU parent, CL&P, PSNH, WMECO, NSTAR Gas and Yankee Gas are parties to a five-year $1.45 billion revolving credit facility. The revolving credit facility is to be used primarily to backstop NU parent's $1.45 billion commercial paper program. The commercial paper program allows NU parent to issue commercial paper as a form of short-term debt. Effective July 23, 2014, NU parent, CL&P, PSNH, WMECO, NSTAR Gas and Yankee Gas extended the expiration date of their joint revolving credit facility for one additional

year to September 6, 2019. CL&P has a borrowing sublimit of $600 million and PSNH and WMECO each have borrowing sublimits of $300 million. As of December 31, 2014 and 2013, NU had approximately $1.1 billion and $1.01 billion, respectively, in short-term borrowings outstanding under the NU parent commercial paper program, leaving $348.9 million and $435.5 million of available borrowing capacity as of December 31, 2014 and 2013, respectively. The weighted-average interest rate on these borrowings as of December 31, 2014 and 2013 was 0.43 percent and 0.24 percent, respectively, which is generally based on A2/P2 rated commercial paper. As of December 31, 2014, there were intercompany loans from NU of $133.4 million to CL&P, $90.5 million to PSNH and $21.4 million to WMECO. As of December 31, 2013, there were intercompany loans from NU of $287.3 million to CL&P and $86.5 million to PSNH.

NSTAR Electric has a five-year $450 million revolving credit facility. This facility serves to backstop NSTAR Electric's existing $450 million commercial paper program. Effective July 23, 2014, NSTAR Electric extended the expiration date of its revolving credit facility for one additional year to September 6, 2019. As of December 31, 2014 and 2013, NSTAR Electric had $302 million and $103.5 million, respectively, in short-term borrowings outstanding under its commercial paper program, leaving $148 million and $346.5 million of available borrowing capacity as of December 31, 2014 and 2013, respectively. The weighted-average interest rate on these borrowings as of December 31, 2014 and 2013 was 0.27 percent and 0.13 percent, respectively, which is generally based on A2/P1 rated commercial paper.

Except as described below, amounts outstanding under the commercial paper programs are included in Notes Payable for NU and NSTAR Electric and classified in current liabilities on the balance sheets as all borrowings are outstanding for no more than 364 days at one time. Intercompany loans from NU to CL&P, PSNH and WMECO are included in Notes Payable to NU Parent and classified in current liabilities on the balance sheets. Intercompany loans from NU to CL&P, PSNH and WMECO are eliminated in consolidation in NU's balance sheets.

On January 15, 2015, NU parent issued $150 million of 1.60 percent Series G Senior Notes due to mature in 2018 and $300 million of 3.15 percent Series H Senior Notes, due to mature in 2025. The proceeds, net of issuance costs, were used to repay short-term borrowings outstanding under the NU commercial paper program. As the debt issuances refinanced short-term debt, the short-term debt was classified as Long-Term Debt as of December 31, 2014. On January 2, 2014, Yankee Gas issued $100 million of Series L First Mortgage Bonds and $25 million of the proceeds was used to repay short-term borrowings outstanding under the NU commercial paper program. As the debt issuance refinanced short-term debt, these amounts were classified as Long-Term Debt on NU's balance sheet as of December 31, 2013. See Note 8, "Long-Term Debt" for further information on these debt issuances.

Under the credit facilities, NU and its subsidiaries must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. As of December 31, 2014 and 2013, NU and its subsidiaries were in compliance with these covenants. If NU or its subsidiaries were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid and additional borrowings by such borrower would not be permitted under its respective credit facility.

8. LONG-TERM DEBT

Details of long-term debt outstanding are as follows:

CL&P	As of December 31,	
(Millions of Dollars)	**2014**	**2013**
First Mortgage Bonds:		
7.875% 1994 Series D due 2024	$ 139.8	$ 139.8
4.800% 2004 Series A due 2014 (1)	-	150.0
5.750% 2004 Series B due 2034	130.0	130.0
5.000% 2005 Series A due 2015	100.0	100.0
5.625% 2005 Series B due 2035	100.0	100.0
6.350% 2006 Series A due 2036	250.0	250.0
5.375% 2007 Series A due 2017	150.0	150.0
5.750% 2007 Series B due 2037	150.0	150.0
5.750% 2007 Series C due 2017	100.0	100.0
6.375% 2007 Series D due 2037	100.0	100.0
5.650% 2008 Series A due 2018	300.0	300.0
5.500% 2009 Series A due 2019	250.0	250.0
2.500% 2013 Series A due 2023	400.0	400.0
4.300% 2014 Series A due 2044 (2)	250.0	-
Total First Mortgage Bonds	2,419.8	2,319.8
Pollution Control Revenue Bonds:		
4.375% Fixed Rate Tax Exempt due 2028	120.5	120.5
1.550% Fixed Rate Tax Exempt due 2031 (3)	62.0	62.0
Total Pollution Control Revenue Bonds	182.5	182.5
Spent Nuclear Fuel Obligation	244.5	244.4
Less Amounts due Within One Year	(162.0)	(150.0)
Unamortized Premiums and Discounts, Net	(4.8)	(5.5)
CL&P Long-Term Debt	$ 2,680.0	$ 2,591.2

NSTAR Electric (Millions of Dollars)	As of December 31, 2014	2013
Debentures:		
4.875% due 2014 [4]	$ -	$ 300.0
5.750% due 2036	200.0	200.0
5.625% due 2017	400.0	400.0
5.500% due 2040	300.0	300.0
2.375% due 2022	400.0	400.0
Variable Rate due 2016 [5]	200.0	200.0
4.400% due 2044 [4]	300.0	-
Total Debentures	1,800.0	1,800.0
Bonds:		
7.375% Tax Exempt Sewage Facility Revenue Bonds, due 2015	4.7	6.4
Total Bonds	4.7	6.4
Less Amounts due Within One Year	(4.7)	(301.7)
Unamortized Premiums and Discounts, Net	(7.3)	(5.3)
NSTAR Electric Long-Term Debt	$ 1,792.7	$ 1,499.4

PSNH (Millions of Dollars)	As of December 31, 2014	2013
First Mortgage Bonds:		
5.25% Series L due 2014 [6]	$ -	$ 50.0
5.60% Series M due 2035	50.0	50.0
6.15% Series N due 2017	70.0	70.0
6.00% Series O due 2018	110.0	110.0
4.50% Series P due 2019	150.0	150.0
4.05% Series Q due 2021	122.0	122.0
3.20% Series R due 2021	160.0	160.0
3.50% Series S due 2023 [7]	325.0	250.0
Total First Mortgage Bonds	987.0	962.0
Pollution Control Revenue Bonds:		
Adjustable Rate Tax Exempt Series A due 2021	89.3	89.3
Total Pollution Control Revenue Bonds	89.3	89.3
Less Amounts due Within One Year	-	(50.0)
Unamortized Premiums and Discounts, Net	-	(2.3)
PSNH Long-Term Debt	$ 1,076.3	$ 999.0

WMECO (Millions of Dollars)	As of December 31, 2014	2013
Notes:		
5.90% Senior Notes Series B, due 2034	$ 50.0	$ 50.0
5.24% Senior Notes Series C, due 2015	50.0	50.0
6.70% Senior Notes Series D, due 2037	40.0	40.0
5.10% Senior Notes Series E, due 2020	95.0	95.0
3.50% Senior Notes Series F, due 2021	250.0	250.0
3.88% Senior Notes Series G, due 2023	80.0	80.0
Total Notes	565.0	565.0
Spent Nuclear Fuel Obligation	57.4	57.3
Less Amounts due Within One Year	(50.0)	-
Unamortized Premiums and Discounts, Net	6.1	7.1
WMECO Long-Term Debt	$ 578.5	$ 629.4

OTHER	As of December 31,	
(Millions of Dollars)	2014	2013
Yankee Gas - First Mortgage Bonds:		
8.48% Series B due 2022	$ 20.0	$ 20.0
4.80% Series G due 2014 [8]	-	75.0
5.26% Series H due 2019	50.0	50.0
5.35% Series I due 2035	50.0	50.0
6.90% Series J due 2018	100.0	100.0
4.87% Series K due 2020	50.0	50.0
4.82% Series L due 2044 [8]	100.0	-
Total First Mortgage Bonds	370.0	345.0
Unamortized Premium	0.6	0.7
Yankee Gas Long-Term Debt	370.6	345.7
NSTAR Gas - First Mortgage Bonds:		
9.95% Series J due 2020	25.0	25.0
7.11% Series K due 2033	35.0	35.0
7.04% Series M due 2017	25.0	25.0
4.46% Series N due 2020	125.0	125.0
NSTAR Gas Long-Term Debt	210.0	210.0
Other - Notes and Debentures:		
1.45% Senior Notes Series E due 2018 (NU Parent)	300.0	300.0
2.80% Senior Notes Series F due 2023 (NU Parent)	450.0	450.0
4.50% Debentures due 2019 (NU Parent)	350.0	350.0
NU Commercial Paper Borrowings[8] [9]	446.3	25.0
Spent Nuclear Fuel Obligation (CYAPC)	179.4	179.4
Total Other Notes and Debentures	1,725.7	1,304.4
Fair Value Adjustment [10]	202.3	230.7
Less Amounts due Within One Year	-	-
Less Fair Value Adjustment - Current Portion [10]	(28.9)	(31.7)
Unamortized Premiums and Discounts, Net	(1.2)	(1.3)
Total Other Long-Term Debt	$ 2,478.5	$ 2,057.8
Total NU Long-Term Debt	$ 8,606.0	$ 7,776.8

(1) On September 15, 2014, CL&P repaid at maturity the $150 million of 4.80 percent 2004 Series A First Mortgage Bonds, using short-term borrowings.

(2) On April 24, 2014, CL&P issued $250 million of 4.30 percent 2014 Series A First Mortgage Bonds, due to mature in 2044. The proceeds, net of issuance costs, were used to repay short-term borrowings.

(3) On February 12, 2015, CL&P notified the trustee that it intends to purchase and cancel the bonds on April 1, 2015, after they have been tendered by the bondholders.

(4) On March 7, 2014, NSTAR Electric issued $300 million of 4.40 percent debentures, due to mature in 2044. The proceeds, net of issuance costs, were used to repay the $300 million of 4.875 percent debentures that matured on April 15, 2014.

(5) As of December 31, 2014 and 2013, the interest rate was 0.4721 percent and 0.478 percent, respectively.

(6) On July 15, 2014, PSNH repaid at maturity the $50 million of 5.25 percent Series L First Mortgage Bonds using short-term borrowings.

(7) On October 14, 2014, PSNH issued $75 million of first mortgage bonds at a yield of 3.144 percent due to mature in 2023. The first mortgage bonds are part of the same series of PSNH's existing 3.50 percent Series S First Mortgage Bonds that were initially issued in November 2013. The proceeds, net of issuance costs, were used to repay short-term borrowings.

(8) On January 2, 2014, Yankee Gas issued $100 million of 4.82 percent Series L First Mortgage Bonds, due to mature in 2044. The proceeds, net of issuance costs, were used to repay the $75 million 4.80 percent Series G First Mortgage Bonds that matured on January 1, 2014 and to pay $25 million in short-term borrowings. As the debt issuance refinanced short-term debt, these amounts were classified as Long-Term Debt on NU's balance sheet as of December 31, 2013.

(9) On January 15, 2015, NU parent issued $150 million of 1.60 percent Series G Senior Notes due to mature in 2018 and $300 million of 3.15 percent Series H Notes, due to mature in 2025. The proceeds, net of issuance costs, were used to repay short-term borrowings outstanding under the NU commercial paper program. As the debt issuances refinanced short-term debt, the short-term debt was classified as Long-Term Debt as of December 31, 2014.

(10) Amount relates to the purchase price adjustment required to record the NSTAR long-term debt at fair value on the date of the merger.

Long-term debt maturities, mandatory tender payments and cash sinking fund requirements on debt outstanding for the years 2015 through 2019 and thereafter are shown below. These amounts exclude the spent nuclear fuel obligation, net unamortized premiums and discounts, and other fair value adjustments as of December 31, 2014:

(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO
2015	$ 216.7	$ 162.0	$ 4.7	$ -	$ 50.0
2016	200.0	-	200.0	-	-
2017	745.0	250.0	400.0	70.0	-
2018	810.0	300.0	-	110.0	-
2019	800.0	250.0	-	150.0	-
Thereafter	4,956.6	1,640.3	1,200.0	746.3	515.0
Total	$ 7,728.3	$ 2,602.3	$ 1,804.7	$ 1,076.3	$ 565.0

The utility plant of CL&P, PSNH, Yankee Gas and NSTAR Gas is subject to the lien of each company's respective first mortgage bond indenture. The NSTAR Electric, WMECO and NU parent debt is unsecured.

CL&P's obligation to repay each series of PCRBs is secured by first mortgage bonds. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. If CL&P fails to meet its obligations under the first mortgage bonds, then the holder of the first mortgage bonds (the issuer of the PCRBs) would have rights under the first mortgage bonds. CL&P's $62 million tax-exempt PCRBs, which are subject to mandatory tender for purchase on April 1, 2015 and carry a coupon rate of 1.55 percent during the current three-year fixed rate period, cannot be redeemed prior to its tender date. CL&P's $120.5 million tax-exempt PCRBs will be subject to redemption at par on or after September 1, 2021. All other long-term debt securities are subject to make-whole provisions.

PSNH's obligation to repay the PCRBs is secured by first mortgage bonds and bond insurance. The first mortgage bonds contain similar terms and provisions as the PCRBs. If PSNH fails to meet its obligations under the first mortgage bonds, then the holder of the first mortgage bonds (the issuer of the PCRBs) would have rights under the first mortgage bonds. The PSNH Series A tax-exempt PCRBs are currently callable at 100 percent of par The PCRBs bear interest at a rate that is periodically set pursuant to auctions. PSNH is not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agent. As of December 31, 2014 and 2013, the interest rate was 0.175 percent and 0.088 percent, respectively.

The long-term debt agreements provide that NU and certain of its subsidiaries must comply with certain covenants as are customarily included in such agreements, including a minimum equity requirement for NSTAR Gas. Under the minimum equity requirement, the outstanding long-term debt of NSTAR Gas must not exceed equity.

Yankee Gas has certain long-term debt agreements that contain cross-default provisions. No other debt issuances contain cross-default provisions as of December 31, 2014.

On August 27, 2014, PURA approved CL&P's request to extend the authorization period for issuance of up to $366.4 million in long-term debt from December 31, 2014 to December 31, 2015.

On October 3, 2014, FERC granted authorization to allow NPT to issue short-term and long-term debt securities in an aggregate amount not to exceed $500 million outstanding at any one time, effective December 31, 2014 through December 31, 2016.

On November 26, 2014, PURA approved Yankee Gas' request to extend the authorization period for issuance of up to $200 million in long-term debt from December 31, 2014 to December 31, 2015.

On January 12, 2015, NSTAR Gas filed an application with the DPU requesting authorization to issue up to $100 million in long-term debt for the period ending December 31, 2015.

Spent Nuclear Fuel Obligation: Under the Nuclear Waste Policy Act of 1982, CL&P and WMECO must pay the DOE for the costs of disposal of spent nuclear fuel and high-level radioactive waste for the period prior to the sale of their ownership shares in the Millstone nuclear power stations. The Millstone Nuclear Generating station was made up of Millstone 1, Millstone 2, and Millstone 3 and all three units were sold in March 2001.

The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Spent Nuclear Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made by CL&P and WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P and WMECO remained responsible for their share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month Treasury bill yield rate. In addition, as a result of consolidating CYAPC, NU has consolidated $179.4 million in additional spent nuclear fuel obligations, including interest, as of both December 31, 2014 and 2013. The obligation due to the DOE for the disposal of CL&P's and WMECO's Prior Period Spent Nuclear Fuel and CYAPC's spent nuclear fuel obligation include accumulated interest costs of $350.4 million and $350.3 million ($178 million and $177.9 million for CL&P and $41.8 million and $41.7 million for WMECO) as of December 31, 2014 and 2013, respectively.

WMECO and CYAPC maintain trusts to fund amounts due to the DOE for the disposal of spent nuclear fuel. For further information on these trusts, see Note 5, "Marketable Securities," to the financial statements.

9. EMPLOYEE BENEFITS

A. Pension Benefits and Postretirement Benefits Other Than Pensions

As of December 31, 2014, NUSCO sponsored two defined benefit retirement plans that covered eligible employees, including employees of CL&P, NSTAR Electric, PSNH and WMECO (NUSCO Pension Plan and NSTAR Pension Plan). Effective January 1, 2015, the two plans were merged into one plan, sponsored by NUSCO. The NUSCO and NSTAR Pension Plans are subject to the provisions of ERISA, as amended by the PPA of 2006. NU's policy is to annually fund the Pension Plans in an amount at least equal to an amount that will satisfy federal requirements. In addition, NU maintains non-qualified defined benefit retirement plans sponsored by NUSCO (herein collectively referred to as the SERP Plans), which provide benefits in excess of Internal Revenue Code limitations to eligible current and retired participants.

As of December 31, 2014, NUSCO also sponsored defined benefit postretirement plans that provide certain retiree benefits, primarily medical, dental and life insurance, to retiring employees that meet certain age and service eligibility requirements (NUSCO PBOP Plans and NSTAR PBOP Plan). Effective January 1, 2015, the plans were merged into one plan, sponsored by NUSCO. Under certain circumstances, eligible retirees are required to contribute to the costs of postretirement benefits. The benefits provided under the PBOP Plans are not vested and the Company has the right to modify any benefit provision subject to applicable laws at that time.

Because the Regulated companies recover the retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of an adjustment to Accumulated Other Comprehensive Income/(Loss) to record the funded status of the Pension, SERP and PBOP Plans. Regulatory accounting was also applied to the portions of the NUSCO costs that support the Regulated companies, as these costs are also recovered from customers. Adjustments to the Pension and PBOP funded status for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information, see Note 2, "Regulatory Accounting," and Note 14, "Accumulated Other Comprehensive Income/(Loss)," to the financial statements. The SERP Plans do not have plan assets.

For the years ended December 31, 2014 and 2013, the expected return on plan assets for the NUSCO Pension and PBOP Plans was calculated by applying the assumed rate of return to a four-year rolling average of plan asset fair values. This calculation recognized investment gains or losses over a four-year period from the years in which they occurred. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return. As investment gains and losses are reflected in the average plan asset fair values, they are subject to amortization with other unrecognized actuarial gains or losses. For the NSTAR Pension and PBOP Plans, the entire difference between the actual return and calculated expected return on plan assets is reflected as a component of unrecognized actuarial gain or loss. Unrecognized actuarial gains or losses are amortized as a component of Pension and PBOP expense over the estimated average future employee service period.

Pension and SERP Plans: As of December 31, 2013, the funded status of the NSTAR Pension Plan was recorded on NSTAR Electric's balance sheet, while the total SERP obligation was recorded on NSTAR Electric & Gas' balance sheet. As of December 31, 2013, all NSTAR employees were employed by NSTAR Electric & Gas. On January 1, 2014, NSTAR Electric & Gas was merged into NUSCO (service company merger) and, concurrently, all employees were transferred to the company they predominantly provide services for: NUSCO, NSTAR Electric or NSTAR Gas. As a result of the employee transfers, the pension and SERP assets and liabilities were attributed by participant and transferred to the applicable company's balance sheets. This change had no impact on the income statement or net assets of NSTAR Electric or NU. For the year ended December 31, 2014, the NUSCO and NSTAR pension and SERP plans are accounted for under the multiple-employer approach, with each company's balance sheet reflecting its share of the funded status of the plans. The following tables provide information on the Pension and SERP Plan benefit obligations, fair values of Pension Plan assets, and funded status:

NU *(Millions of Dollars)*	Pension and SERP As of December 31, 2014	 2013
Change in Benefit Obligation		
Benefit Obligation as of Beginning of Year	$ (4,676.5)	$ (5,022.8)
Service Cost	(79.9)	(102.3)
Interest Cost	(225.7)	(206.7)
Actuarial Gain/(Loss)	(739.6)	433.6
Benefits Paid - Pension	230.3	216.6
Benefits Paid - SERP	5.2	5.1
Benefit Obligation as of End of Year	$ (5,486.2)	$ (4,676.5)
Change in Pension Plan Assets		
Fair Value of Plan Assets as of Beginning of Year	$ 3,985.9	$ 3,411.3
Employer Contributions	171.6	284.7
Actual Return on Plan Assets	199.3	506.5
Benefits Paid	(230.3)	(216.6)
Fair Value of Plan Assets as of End of Year	$ 4,126.5	$ 3,985.9
Funded Status as of December 31st	$ (1,359.7)	$ (690.6)

	Pension and SERP							
	As of December 31, 2014				As of December 31, 2013			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric [1]	PSNH	WMECO
Change in Benefit Obligation								
Benefit Obligation as of Beginning of Year	$ (1,083.4)	$ (1,353.3)	$ (529.0)	$ (223.9)	$ (1,178.0)	$ (1,430.0)	$ (576.0)	$ (243.1)
Decrease due to transfer of employees	26.4	479.9	32.2	6.2	-	-	-	-
Service Cost	(20.2)	(13.6)	(9.7)	(3.5)	(24.9)	(33.1)	(13.1)	(4.7)
Interest Cost	(50.5)	(41.3)	(23.8)	(10.3)	(48.3)	(58.0)	(23.6)	(10.0)
Actuarial Gain/(Loss)	(161.0)	(107.0)	(73.3)	(29.8)	110.7	96.6	62.4	22.4
Benefits Paid - Pension	58.3	52.4	22.8	11.9	56.6	71.2	21.1	11.5
Benefits Paid - SERP	0.3	0.3	0.1	-	0.5	-	0.2	-
Benefit Obligation as of End of Year	$ (1,230.1)	$ (982.6)	$ (580.7)	$ (249.4)	$ (1,083.4)	$ (1,353.3)	$ (529.0)	$ (223.9)
Change in Pension Plan Assets								
Fair Value of Plan Assets as of Beginning of Year	$ 1,016.3	$ 1,235.3	$ 528.6	$ 240.4	$ 937.6	$ 1,069.1	$ 386.6	$ 218.5
Decrease due to transfer of employees	(26.4)	(441.4)	(32.2)	(6.2)	-	-	-	-
Employer Contributions	-	101.0	-	-	-	82.0	108.3	-
Actual Return on Plan Assets	49.2	36.5	24.8	11.7	135.3	155.4	54.8	33.4
Benefits Paid	(58.3)	(52.4)	(22.8)	(11.9)	(56.6)	(71.2)	(21.1)	(11.5)
Fair Value of Plan Assets as of End of Year	$ 980.8	$ 879.0	$ 498.4	$ 234.0	$ 1,016.3	$ 1,235.3	$ 528.6	$ 240.4
Funded Status as of December 31st	$ (249.3)	$ (103.6)	$ (82.3)	$ (15.4)	$ (67.1)	$ (118.0)	$ (0.4)	$ 16.5

[1] NSTAR Electric amounts do not include benefit obligations of the NSTAR SERP Plan as of December 31, 2013.

During 2014, the Society of Actuaries released a series of updated mortality tables resulting from recent studies that measured mortality rates for various groups of individuals. The updated mortality tables released in 2014 increased life expectancy of plan participants by 3 to 5 years and have the effect of increasing the estimate of benefits to be provided to plan participants. The impact of this adoption on NU's funded status liability for the year ended December 31, 2014 was an increase of approximately $340 million. In addition, the decreases in the discount rates resulted in an increase on NU's funded status liability of approximately $530 million. Partially offsetting these increases are the impact of other actuarial assumptions.

As of December 31, 2013, prepaid pension assets for PSNH and WMECO were included in Other Long-Term Assets on their accompanying balance sheets. The pension and SERP benefits funded status includes the current portion of the SERP liability, which is included in Other Current Liabilities on the accompanying balance sheets. Although NU maintains marketable securities in a supplemental benefit trust, the SERP plan itself does not contain any assets. See Note 5, "Marketable Securities," to the financial statements.

The accumulated benefit obligation for the Pension and SERP Plans is as follows:

(Millions of Dollars)	NU	CL&P	NSTAR Electric [1]	PSNH	WMECO
2014	$ 5,000.1	$ 1,101.4	$ 910.4	$ 524.5	$ 226.4
2013	4,538.8	1,058.0	1,280.6	520.1	220.6

[1] NSTAR Electric amounts do not include the accumulated benefit obligation for the SERP Plan as of December 31, 2013.

The following actuarial assumptions were used in calculating the Pension and SERP Plans' year end funded status:

	Pension and SERP	
	As of December 31,	
	2014	2013
Discount Rate	4.20 %	4.85 % - 5.03 %
Compensation/Progression Rate	3.50 %	3.50 % - 4.00 %

Pension and SERP Expense: NU charges net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked for each subsidiary. The actual investment return in the trust is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. For the years ended December 31, 2013 and 2012 (prior to the service company merger), the net periodic pension expense recorded at NSTAR Electric represented the full cost of the plan with a portion of the costs allocated to affiliated companies based on participant demographic data.

The components of net periodic benefit expense for the Pension and SERP Plans are shown below. The net periodic benefit expense and the intercompany allocations less the capitalized portion of pension is included in Operations and Maintenance on the statements of income. Capitalized pension amounts relate to employees working on capital projects and are included in Property, Plant and Equipment, Net. Intercompany allocations are not included in the CL&P, NSTAR Electric, PSNH and WMECO net periodic benefit expense amounts. Pension and SERP expense reflected in the statements of cash flows for CL&P, NSTAR Electric, PSNH and WMECO does not include the intercompany allocations and the corresponding capitalized portion, as these amounts are cash settled on a short-term basis.

	Pension and SERP				
	For the Year Ended December 31, 2014				
(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO
Service Cost	$ 79.9	$ 20.2	$ 13.6	$ 9.7	$ 3.5
Interest Cost	225.7	50.5	41.3	23.8	10.3
Expected Return on Plan Assets	(310.8)	(75.4)	(63.0)	(38.1)	(17.9)
Actuarial Loss	128.4	33.7	23.5	11.6	6.9
Prior Service Cost	4.4	1.8	-	0.7	0.4
Total Net Periodic Benefit Expense	$ 127.6	$ 30.8	$ 15.4	$ 7.7	$ 3.2
Intercompany Allocations	N/A	$ 26.7	$ 10.4	$ 7.6	$ 5.1
Capitalized Pension Expense	$ 35.2	$ 17.6	$ 7.9	$ 3.0	$ 2.4

	Pension and SERP				
	For the Year Ended December 31, 2013				
(Millions of Dollars)	NU	CL&P	NSTAR Electric [(1)]	PSNH	WMECO
Service Cost	$ 102.3	$ 24.9	$ 33.1	$ 13.1	$ 4.7
Interest Cost	206.7	48.3	58.0	23.6	10.0
Expected Return on Plan Assets	(278.1)	(73.8)	(84.4)	(35.4)	(17.4)
Actuarial Loss	210.5	55.9	58.1	21.6	11.8
Prior Service Cost/(Credit)	4.0	1.8	(0.3)	0.7	0.4
Total Net Periodic Benefit Expense	$ 245.4	$ 57.1	$ 64.5	$ 23.6	$ 9.5
Intercompany Allocations	N/A	$ 44.9	$ (8.4)	$ 10.5	$ 8.0
Capitalized Pension Expense	$ 73.2	$ 28.0	$ 28.9	$ 7.3	$ 5.2

	Pension and SERP				
	For the Year Ended December 31, 2012				
(Millions of Dollars)	NU [(2)]	CL&P	NSTAR Electric [(1)]	PSNH	WMECO
Service Cost	$ 84.3	$ 21.8	$ 30.3	$ 11.8	$ 4.1
Interest Cost	198.3	51.2	58.9	24.4	10.5
Expected Return on Plan Assets	(220.9)	(70.6)	(65.6)	(28.2)	(16.4)
Actuarial Loss	172.4	49.6	63.1	16.2	10.7
Prior Service Cost/(Credit)	7.9	3.6	(0.6)	1.5	0.8
Total Net Periodic Benefit Expense	$ 242.0	$ 55.6	$ 86.1	$ 25.7	$ 9.7
Curtailments and Settlements	$ 2.2	$ -	$ -	$ -	$ -
Intercompany Allocations	N/A	$ 42.8	$ (12.3)	$ 10.1	$ 8.1
Capitalized Pension Expense	$ 70.6	$ 26.8	$ 30.7	$ 7.9	$ 5.1

(1) NSTAR Electric's allocated expense associated with the NSTAR SERP was $3.2 million and $3.6 million for the years ended December 31, 2013 and 2012, respectively, and were not included in the NSTAR Electric amounts in the tables above. For the year ended December 31, 2014, the SERP amounts are now allocated to NSTAR Electric due to the service company merger.

(2) NSTAR amounts were included in NU beginning April 10, 2012.

The following actuarial assumptions were used to calculate Pension and SERP expense amounts:

	Pension and SERP		
	For the Years Ended December 31,		
	2014	2013	2012
Discount Rate	4.85 % - 5.03 %	4.13 % - 4.24 %	4.52 % - 5.03 %
Expected Long-Term Rate of Return	8.25 %	8.25 %	7.30 % - 8.25 %
Compensation/Progression Rate	3.50 % - 4.00 %	3.50 % - 4.00 %	3.50 % - 4.00 %

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and Other Comprehensive Income (OCI) as well as amounts in Regulatory Assets and OCI reclassified as net periodic benefit expense during the years presented:

	Amounts Reclassified To/From			
	Regulatory Assets		OCI	
	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	2014	2013
Actuarial (Gains)/Losses Arising During the Year	$ 797.3	$ (635.2)	$ 55.9	$ (28.9)
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(122.8)	(201.2)	(5.6)	(9.4)
Prior Service Cost Reclassified as Net Periodic Benefit Expense	(4.2)	(3.8)	(0.2)	(0.2)

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Loss amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2014 and 2013, and the amounts that are expected to be recognized as components in 2015:

	Regulatory Assets as of December 31,		Expected 2015	AOCI as of December 31,		Expected 2015
(Millions of Dollars)	2014	2013	Expense	2014	2013	Expense
Actuarial Loss	$ 1,811.9	$ 1,137.4	$ 149.1	$ 93.5	$ 43.2	$ 6.4
Prior Service Cost	13.2	17.4	3.5	0.8	1.0	0.2

PBOP Plans: As of December 31, 2013, the funded status of the NSTAR PBOP Plan was recorded on the NSTAR Electric & Gas balance sheet. As of December 31, 2013, all NSTAR employees were employed by NSTAR Electric & Gas. On January 1, 2014, concurrent with the service company merger, the PBOP assets and liabilities were attributed by participant and transferred to the applicable company's balance sheets. This change had no impact on the income statement or net assets of NSTAR Electric or NU. For the year ended December 31, 2014, the NUSCO and NSTAR PBOP Plans are accounted for under the multiple-employer approach, with each company's balance sheet reflecting its share of the funded status of the plans.

NU annually funds postretirement costs through tax deductible contributions to external trusts.

The following tables provide information on PBOP Plan benefit obligations, fair values of plan assets, and funded status:

NU	PBOP	
	As of December 31,	
(Millions of Dollars)	2014	2013
Change in Benefit Obligation		
Benefit Obligation as of Beginning of Year	$ (1,038.0)	$ (1,233.3)
Service Cost	(12.5)	(16.9)
Interest Cost	(49.5)	(47.2)
Actuarial Gain/(Loss)	(95.5)	200.9
Benefits Paid	47.6	58.5
Benefit Obligation as of End of Year	$ (1,147.9)	$ (1,038.0)
Change in PBOP Plan Assets		
Fair Value of Plan Assets as of Beginning of Year	$ 826.5	$ 709.1
Actual Return on Plan Assets	43.7	118.3
Employer Contributions	40.0	57.6
Benefits Paid	(47.6)	(58.5)
Fair Value of Plan Assets as of End of Year	$ 862.6	$ 826.5
Funded Status as of December 31st	$ (285.3)	$ (211.5)

	PBOP						
	As of December 31,						
	2014				2013		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	PSNH	WMECO
Change in Benefit Obligation							
Benefit Obligation as of Beginning of Year	$ (180.4)	$ -	$ (93.5)	$ (38.7)	$ (196.8)	$ (100.2)	$ (42.5)
Decrease/(Increase) due to transfer of employees	3.7	(395.5)	4.3	1.0	-	-	-
Service Cost	(2.2)	(3.1)	(1.3)	(0.4)	(3.4)	(2.3)	(0.7)
Interest Cost	(8.1)	(19.4)	(4.3)	(1.7)	(7.9)	(4.0)	(1.7)
Actuarial Gain/(Loss)	3.5	(68.6)	(1.1)	1.3	13.3	7.2	3.3
Benefits Paid	9.6	17.9	4.1	1.9	14.4	5.8	2.9
Benefit Obligation as of End of Year	$ (173.9)	$ (468.7)	$ (91.8)	$ (36.6)	$ (180.4)	$ (93.5)	$ (38.7)
Change in PBOP Plan Assets							
Fair Value of Plan Assets as of Beginning of Year	$ 151.3	$ -	$ 81.8	$ 35.3	$ 132.2	$ 69.5	$ 31.0
(Decrease)/Increase due to transfer of employees	(3.2)	316.7	(3.1)	(1.0)	-	-	-
Actual Return on Plan Assets	6.3	18.4	3.8	1.6	24.8	13.4	6.0
Employer Contributions	4.2	19.3	2.5	0.4	8.7	4.7	1.2
Benefits Paid	(9.6)	(17.9)	(4.1)	(1.9)	(14.4)	(5.8)	(2.9)
Fair Value of Plan Assets as of End of Year	$ 149.0	$ 336.5	$ 80.9	$ 34.4	$ 151.3	$ 81.8	$ 35.3
Funded Status as of December 31st	$ (24.9)	$ (132.2)	$ (10.9)	$ (2.2)	$ (29.1)	$ (11.7)	$ (3.4)

During 2014, the Society of Actuaries released a series of updated mortality tables resulting from recent studies that measured mortality rates for various groups of individuals. The updated mortality tables released in 2014 increased life expectancy of plan participants by 3 to 5 years and have the effect of increasing the estimate of benefits to be provided to plan participants. The impact of this adoption on NU's funded status liability for the

year ended December 31, 2014 was an increase of approximately $82 million. In addition, the decreases in the discount rates resulted in an increase on NU's funded status liability of approximately $110 million. Partially offsetting these increases are the impact of other actuarial assumptions.

The following actuarial assumptions were used in calculating the PBOP Plans' year end funded status:

	PBOP As of December 31, 2014	PBOP As of December 31, 2013
Discount Rate	4.22 %	4.78 % - 5.10 %
Health Care Cost Trend Rate	6.50 %	7.00 %

PBOP Expense: NU charges net periodic postretirement benefits expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked for each subsidiary. The actual investment return in the trust each year is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. For the years ended December 31, 2013 and 2012 (prior to the service company merger), the net periodic postretirement expense of the NSTAR PBOP Plan allocated to NSTAR Electric was $4.6 million and $34.1 million, respectively.

The components of net periodic benefit expense for the PBOP Plans are shown below. The net periodic benefit expense and the intercompany allocations less the capitalized portion of PBOP is included in Operations and Maintenance on the statements of income. Capitalized PBOP amounts relate to employees working on capital projects and are included in Property, Plant and Equipment, Net. Intercompany allocations are not included in the CL&P, NSTAR Electric, PSNH and WMECO net periodic benefit expense amounts. PBOP expense reflected in the statements of cash flows for CL&P, NSTAR Electric, PSNH and WMECO does not include the intercompany allocations and the corresponding capitalized portion, as these amounts are cash settled on a short-term basis.

PBOP — For the Year Ended December 31, 2014

(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO
Service Cost	$ 12.5	$ 2.2	$ 3.1	$ 1.3	$ 0.4
Interest Cost	49.5	8.1	19.4	4.3	1.7
Expected Return on Plan Assets	(63.3)	(10.5)	(25.9)	(5.4)	(2.3)
Actuarial Loss/(Gain)	12.2	4.2	(0.5)	2.2	0.5
Prior Service Credit	(2.8)	-	(1.9)	-	-
Total Net Periodic Benefit Expense/(Income)	$ 8.1	$ 4.0	$ (5.8)	$ 2.4	$ 0.3
Intercompany Allocations	N/A	$ 3.8	$ 0.8	$ 1.0	$ 0.7
Capitalized PBOP Expense/(Income)	$ 1.4	$ 1.8	$ (2.3)	$ 0.8	$ 0.2

PBOP — For the Year Ended December 31, 2013

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
Service Cost	$ 16.9	$ 3.4	$ 2.3	$ 0.7
Interest Cost	47.2	7.9	4.0	1.7
Expected Return on Plan Assets	(55.4)	(10.1)	(5.2)	(2.3)
Actuarial Loss	26.0	7.4	3.6	1.1
Prior Service Credit	(2.1)	-	-	-
Total Net Periodic Benefit Expense	$ 32.6	$ 8.6	$ 4.7	$ 1.2
Intercompany Allocations	N/A	$ 7.1	$ 1.6	$ 1.3
Capitalized PBOP Expense	$ 8.8	$ 3.9	$ 1.3	$ 0.6

PBOP — For the Year Ended December 31, 2012

(Millions of Dollars)	NU [1]	CL&P	PSNH	WMECO
Service Cost	$ 15.7	$ 3.0	$ 2.0	$ 0.6
Interest Cost	49.0	9.2	4.6	2.0
Expected Return on Plan Assets	(39.2)	(9.1)	(4.6)	(2.1)
Actuarial Loss	36.0	7.5	3.6	1.2
Prior Service Credit	(1.4)	-	-	-
Net Transition Obligation Cost	12.2	6.1	2.5	1.3
Total Net Periodic Benefit Expense	$ 72.3	$ 16.7	$ 8.1	$ 3.0
Intercompany Allocations	N/A	$ 7.9	$ 2.0	$ 1.5
Capitalized PBOP Expense	$ 26.6	$ 8.2	$ 2.3	$ 1.6

[1] NSTAR amounts were included in NU beginning April 10, 2012.

The following actuarial assumptions were used to calculate PBOP expense amounts:

	PBOP		
	For the Years Ended December 31,		
	2014	2013	2012
Discount Rate	4.78 % - 5.10 %	4.04 % - 4.35 %	4.58 % - 4.84 %
Expected Long-Term Rate of Return	8.25 %	8.25 %	7.30 % - 8.25 %

As of December 31, 2014 and 2013, the health care cost trend rate assumption used to determine the PBOP Plans' funded status was 6.5 percent and 7 percent, respectively, subsequently decreasing to an ultimate rate of 4.5 percent in 2023. The health care cost trend rate assumption used to calculate the PBOP expense amounts was 7 percent for the year ended December 31, 2014.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point for the year ended December 31, 2014 would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on PBOP Obligation	$ 111.2	$ (88.4)
Effect on Total Service and Interest Cost Components	5.3	(4.4)

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and OCI as well as amounts in Regulatory Assets and OCI reclassified as net periodic benefit (expense)/income during the years presented:

	Amounts Reclassified To/From			
	Regulatory Assets		OCI	
	For the Years Ended December 31,			
(Millions of Dollars)	2014	2013	2014	2013
Actuarial Losses/(Gains) Arising During the Year	$ 115.1	$ (262.0)	$ 0.4	$ (1.9)
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(11.6)	(24.9)	(0.6)	(1.1)
Prior Service Credit Reclassified as Net Periodic Benefit Income	2.8	2.1	-	-

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Loss amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2014 and 2013, and the amounts that are expected to be recognized as components in 2015:

	Regulatory Assets as of December 31,		Expected 2015	AOCI as of December 31,		Expected 2015
(Millions of Dollars)	2014	2013	Expense	2014	2013	Expense
Actuarial Loss	$ 192.7	$ 89.2	$ 6.9	$ 6.0	$ 6.2	$ 0.3
Prior Service Credit	(1.8)	(4.6)	(0.5)	-	-	-

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid by the Pension, SERP and PBOP Plans:

(Millions of Dollars)	2015	2016	2017	2018	2019	2020-2024
Pension and SERP	$ 244.5	$ 253.6	$ 268.9	$ 273.4	$ 285.4	$ 1,591.1
PBOP	58.7	59.7	60.6	61.3	62.0	318.8

Contributions: NU contributed $171.6 million to the Pension Plans in 2014, of which $101 million was contributed by NSTAR Electric. Based on the current status of the Pension Plans, NU expects to make contributions of approximately $155 million in 2015, of which $5 million will be contributed by NSTAR Electric and $1 million will be contributed by PSNH. The remaining $149 million is expected to be contributed by other NU subsidiaries, primarily NUSCO.

NU contributed $40 million to the PBOP Plans in 2014 and expects to make approximately $27 million in contributions in 2015. This amount will be funded into the 401(h) account and VEBAs up to the maximum tax-deductible level permitted.

Fair Value of Pension and PBOP Plan Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for Pension and PBOP payments. NU's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment strategy for each asset category includes a diversification of asset types, fund strategies and fund managers and establishes target asset allocations that are routinely reviewed and periodically rebalanced. PBOP assets are comprised of assets held in the PBOP Plans as well as specific assets within the defined benefit pension plan trust (401(h) assets). The investment policy and strategy of the 401(h) assets is consistent with those of the defined benefit pension plans. NU's expected long-term rates of return on Pension and PBOP Plan assets are based on target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, NU evaluated input from consultants, as well as long-term inflation assumptions and historical returns. For the year ended December 31, 2014, management has assumed long-term rates of return of 8.25 percent for the Pension and PBOP Plan assets. These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31, 2014 and 2013	
	Pension and Tax-Exempt PBOP Plans	
	Target Asset Allocation	Assumed Rate of Return
Equity Securities:		
United States	24%	9%
International	10%	9%
Emerging Markets	6%	10%
Private Equity	10%	13%
Debt Securities:		
Fixed Income	15%	5%
High Yield Fixed Income	9%	7.5%
Emerging Markets Debt	6%	7.5%
Real Estate and Other Assets	9%	7.5%
Hedge Funds	11%	7%

The Taxable PBOP Plans have a target asset allocation of 70 percent equity securities and 30 percent fixed income securities.

The following table presents, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	NU Pension Plans							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2014				2013			
Asset Category:	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Equity Securities [1]	$ 414.7	$ 1,035.0	$ 292.2	$ 1,741.9	$ 326.8	$ 1,172.1	$ 255.5	$ 1,754.4
Private Equity	18.8	-	367.9	386.7	96.4	-	300.3	396.7
Fixed Income [2]	10.2	561.4	722.0	1,293.6	11.6	605.1	589.5	1,206.2
Real Estate and Other Assets	-	132.0	265.8	397.8	-	88.2	288.5	376.7
Hedge Funds	-	20.0	475.0	495.0	-	-	416.9	416.9
Total Master Trust Assets	$ 443.7	$ 1,748.4	$ 2,122.9	$ 4,315.0	$ 434.8	$ 1,865.4	$ 1,850.7	$ 4,150.9
Less: 401(h) PBOP Assets [3]				(188.5)				(165.0)
Total Pension Assets				$ 4,126.5				$ 3,985.9

	NU PBOP Plans							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2014				2013			
Asset Category:	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and Cash Equivalents	$ -	$ -	$ -	$ -	$ 11.1	$ -	$ -	$ 11.1
Equity Securities [1]	104.1	172.8	75.1	352.0	110.3	176.8	69.1	356.2
Private Equity	-	-	24.9	24.9	-	-	17.9	17.9
Fixed Income [2]	16.1	110.0	78.3	204.4	-	119.7	51.5	171.2
Real Estate and Other Assets		19.4	15.0	34.4	-	14.2	33.9	48.1
Hedge Funds		-	58.4	58.4	-	-	57.0	57.0
Total	$ 120.2	$ 302.2	$ 251.7	$ 674.1	$ 121.4	$ 310.7	$ 229.4	$ 661.5
Add: 401(h) PBOP Assets [3]				188.5				165.0
Total PBOP Assets				$ 862.6				$ 826.5

(1) United States, International and Emerging Markets equity securities classified as Level 2 include investments in commingled funds. Level 3 investments include hedge funds that are overlayed with equity index swaps and futures contracts and funds invested in equities that have redemption restrictions.

(2) Fixed Income investments classified as Level 3 investments include fixed income funds that invest in a variety of opportunistic fixed income strategies, and hedge funds that are overlayed with fixed income futures.

(3) The assets of the Pension Plans include a 401(h) account that has been allocated to provide health and welfare postretirement benefits under the PBOP Plans.

Effective January 1, 2013, the NSTAR Pension Plan assets were transferred into the NUSCO Pension Plan master trust. The NUSCO Pension Plan is entitled to approximately 66 percent of each asset category in the master trust, the NSTAR Pension Plan is entitled to approximately 30 percent of each asset category in the master trust and the 401(h) plans are entitled to approximately four percent of each asset category in the master trust. For the years ended December 31, 2014 and 2013 the NUSCO Pension Plan was entitled to $2,803.6 million and $2,750.4 million respectively and the NSTAR Pension Plan was entitled to $1,322.9 million and $1,235.3 million, respectively. Also effective January 1, 2013, the NSTAR PBOP Plan

assets were transferred into a master trust with the NUSCO PBOP Plan assets and assets were allocated to each plan. For the years ended December 31, 2014 and 2013, the NUSCO PBOP Plan was entitled to $399 million and $391 million, respectively, and the NSTAR PBOP Plan was entitled to $463.6 million and $435.5 million, respectively. CL&P, PSNH and WMECO are allocated a portion of the NUSCO Pension and PBOP Plan assets. NSTAR Electric is entitled to a portion of the NSTAR Pension and PBOP Plan assets.

The Company values assets based on observable inputs when available. Equity securities, exchange traded funds and futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date. Commingled funds included in Level 2 equity securities are recorded at the net asset value provided by the asset manager, which is based on the market prices of the underlying equity securities. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows. Fixed income securities, such as government issued securities, corporate bonds and high yield bond funds, are included in Level 2 and are valued using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures. Hedge funds and investments in opportunistic fixed income funds are recorded at net asset value based on the values of the underlying assets. The assets in the hedge funds and opportunistic fixed income funds are valued using observable inputs and are classified as Level 3 within the fair value hierarchy due to redemption restrictions. Private Equity investments and Real Estate and Other Assets are valued using the net asset value provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or public market comparables of the underlying investments. These investments are classified as Level 3 due to redemption restrictions.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3): The following tables present changes in the Level 3 category of Pension and PBOP Plan assets for the years ended December 31, 2014 and 2013:

	NU Pension Plans					
(Millions of Dollars)	Equity Securities	Private Equity	Fixed Income	Real Estate and Other Assets	Hedge Funds	Total
Balance as of January 1, 2013	$ 322.7	$ 267.9	$ 315.1	$ 235.4	$ 418.9	$ 1,560.0
Transfer Between Categories	-	-	32.5	-	(32.5)	-
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	20.6	15.4	55.3	12.9	33.4	137.6
Relating to Assets Distributed During the Year	12.2	13.7	(1.0)	6.2	-	31.1
Purchases, Sales and Settlements	(100.0)	3.3	187.6	34.0	(2.9)	122.0
Balance as of December 31, 2013	$ 255.5	$ 300.3	$ 589.5	$ 288.5	$ 416.9	$ 1,850.7
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	(2.3)	14.0	45.2	(3.6)	23.5	76.8
Relating to Assets Distributed During the Year	-	13.9	(6.2)	28.3	(15.2)	20.8
Purchases, Sales and Settlements	39.0	39.7	93.5	(47.4)	49.8	174.6
Balance as of December 31, 2014	$ 292.2	$ 367.9	$ 722.0	$ 265.8	$ 475.0	$ 2,122.9

	NU PBOP Plans					
(Millions of Dollars)	Equity Securities	Private Equity	Fixed Income	Real Estate and Other Assets	Hedge Funds	Total
Balance as of January 1, 2013	$ 36.3	$ 11.3	$ 32.1	$ 26.7	$ 39.6	$ 146.0
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	20.8	1.5	4.1	3.9	5.4	35.7
Relating to Assets Distributed During the Year	-	0.2	-	(0.1)	-	0.1
Purchases, Sales and Settlements	12.0	4.9	15.3	3.4	12.0	47.6
Balance as of December 31, 2013	$ 69.1	$ 17.9	$ 51.5	$ 33.9	$ 57.0	$ 229.4
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	6.0	1.3	1.9	(2.8)	1.4	7.8
Relating to Assets Distributed During the Year	-	0.1	-	(2.2)	-	(2.1)
Purchases, Sales and Settlements	-	5.6	24.9	(13.9)	-	16.6
Balance as of December 31, 2014	$ 75.1	$ 24.9	$ 78.3	$ 15.0	$ 58.4	$ 251.7

B. Defined Contribution Plans

Effective January 1, 2014, NU maintains one defined contribution plan on behalf of eligible participants, the NUSCO 401k Plan. The NUSCO 401k Plan provides for employee and employer contributions up to statutory limits. For eligible employees, the NUSCO 401k Plan provides employer matching contributions of either 100 percent up to a maximum of three percent of eligible compensation or 50 percent up to a maximum of eight percent of eligible compensation. For newly hired employees beginning in 2014, the NUSCO 401k Plan provides employer matching contributions of 100 percent up to a maximum of three percent of eligible compensation.

The NUSCO 401k Plan also contains a K-Vantage feature on behalf of eligible participants, which provides an additional employer contribution based on age and years of service. K-Vantage participants are not eligible to actively participate in the NU defined benefit plans.

The total defined contribution plan employer matching contributions, including the K-Vantage program contributions, were as follows:

(Millions of Dollars)	NU [(1)]	CL&P	NSTAR Electric	PSNH	WMECO
2014	$ 29.7	$ 5.0	$ 6.3	$ 3.2	$ 1.0
2013	37.0	5.1	8.5	3.3	1.0
2012	25.7	4.8	9.0	3.3	0.9

(1) NSTAR amounts were included in NU beginning April 10, 2012.

Allocations of NU common shares were made from NU treasury shares to satisfy the NUSCO 401k Plan obligation to provide 100 percent of the matching contribution in NU common shares. For treasury shares used to satisfy the NUSCO 401k Plan employer matching contributions, compensation expense is recognized equal to the fair value of shares that have been allocated to participants. Any difference between the fair value and the average cost of the allocated treasury shares is charged or credited to Capital Surplus, Paid In. For the years ended December 31, 2014, 2013 and 2012, NU recognized $22 million, $9.1 million and $8.9 million, respectively, of compensation expense related to treasury shares used to satisfy the matching contribution.

C. Share-Based Payments

Share-based compensation awards are recorded using a fair-value-based method at the date of grant. NU, CL&P, NSTAR Electric, PSNH and WMECO record compensation expense related to these awards, as applicable, for shares issued or sold to their respective employees and officers, as well as the allocation of costs associated with shares issued or sold to NU's service company employees and officers that support CL&P, NSTAR Electric, PSNH and WMECO.

Upon consummation of the merger with NSTAR, the NSTAR 1997 Share Incentive Plan and the NSTAR 2007 Long-Term Incentive Plan were assumed by NU. Share-based awards granted under the NSTAR Plans and held by NSTAR employees and officers were generally converted into outstanding NU share-based compensation awards with an estimated fair value of $53.2 million. Refer to Note 21, "Merger of NU and NSTAR," for further information regarding the merger transaction. Specifically, as of the merger closing, and as adjusted by the exchange ratio, NU converted (1) outstanding NSTAR stock options into 2,664,894 NU stock options valued at $30.5 million, (2) NSTAR deferred shares and NSTAR performance shares into 421,775 NU RSU's valued at $15.5 million, and (3) NSTAR RSU retention awards into 195,619 NU RSU retention awards valued at $7.2 million.

NU Incentive Plans: NU maintains long-term equity-based incentive plans in which NU, CL&P, NSTAR Electric, PSNH and WMECO employees, officers and board members are eligible to participate. The incentive plans authorize NU to grant up to 8,000,000 new shares for various types of awards, including RSUs and performance shares, to eligible employees, officers, and board members. As of December 31, 2014 and 2013, NU had 3,112,020 and 3,440,590 common shares, respectively, available for issuance under these plans. NU also maintains an ESPP for eligible employees.

NU accounts for its various share-based plans as follows:

- RSUs - NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period based upon the fair value of NU's common shares at the date of grant. The par value of RSUs is reclassified to Common Stock from APIC as RSUs become issued as common shares.

- Performance Shares - NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period. Performance shares vest based upon the extent to which Company goals are achieved. Vesting of outstanding performance shares is based upon both the Company's EPS growth over the requisite service period and the total shareholder return as compared to the Edison Electric Institute (EEI) Index during the requisite service period. The fair value of performance shares is determined at the date of grant using a lattice model.

- Stock Options - Stock options issued under the NSTAR Incentive Plan that were outstanding immediately prior to the completion of the merger with NSTAR converted into fully vested options to acquire NU common shares, as adjusted by the exchange ratio. The fair value of these awards on the merger date was included in the purchase price as it represented consideration transferred in the merger. Accordingly, no compensation expense was recorded for these stock options.

- ESPP Shares - For shares sold under the ESPP, no compensation expense was recorded as the ESPP qualifies as a non-compensatory plan.

RSUs: NU granted RSUs under the annual long-term incentive programs that are subject to three-year graded vesting schedules for employees, and one-year graded vesting schedules, or immediate vesting, for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings for income taxes, subsequent to vesting. A summary of RSU transactions is as follows:

	RSUs (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of January 1, 2012	959,920	$ 26.36
Granted	614,930	$ 33.04
Converted NSTAR Awards upon Merger	617,394	$ 36.79
Converted from NU Performance Shares upon Merger	451,358	$ 34.32
Shares issued	(363,779)	$ 29.05
Forfeited	(96,504)	$ 34.97
Outstanding as of December 31, 2012	2,183,319	$ 31.99
Granted	373,939	$ 39.56
Shares issued	(891,129)	$ 32.15
Forfeited	(29,689)	$ 33.75
Outstanding as of December 31, 2013	1,636,440	$ 33.61
Granted	338,576	$ 42.27
Shares issued	(567,209)	$ 33.48
Forfeited	(27,060)	$ 39.62
Outstanding as of December 31, 2014	1,380,747	$ 35.67

As of December 31, 2014 and 2013, the number and weighted average grant-date fair value of unvested RSUs was 1,024,729 and $38.14 per share, and 1,162,216 and $36.58 per share, respectively. The number and weighted average grant-date fair value of RSUs vested and either paid or deferred during 2014 was 437,887 and $37.36 per share, respectively. As of December 31, 2014, 356,018 RSUs were fully vested and deferred and an additional 973,493 are expected to vest.

Performance Shares: NU granted performance shares under the annual long-term incentive programs that vest based upon the extent to which Company goals are achieved at the end of three-year performance measurement periods. Performance shares are paid in shares, after the performance measurement period. A summary of performance share transactions is as follows:

	Performance Shares (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of January 1, 2012	483,133	$ 29.18
Granted	225,935	$ 35.09
Converted to RSUs upon Merger	(451,358)	$ 34.32
Shares issued	(106,773)	$ 24.52
Outstanding as of December 31, 2012	150,937	$ 25.04
Granted	191,961	$ 40.96
Shares issued	(150,944)	$ 25.04
Forfeited	(1,526)	$ 40.93
Outstanding as of December 31, 2013	190,428	$ 40.96
Granted	193,396	$ 43.40
Shares issued	(2,009)	$ 41.46
Forfeited	(6,171)	$ 42.02
Outstanding as of December 31, 2014	375,644	$ 42.20

Upon closing of the merger with NSTAR, 451,358 performance shares under the NU 2011 and 2012 Long-Term Incentive Programs converted to RSUs according to the terms of these programs. Performance shares under the NU 2010 Incentive Program were measured based upon a modified performance period through the date of the merger, in accordance with the terms of the program, and were fully distributed in 2013.

The total compensation expense and associated future income tax benefit recognized by NU, CL&P, NSTAR Electric, PSNH and WMECO for share-based compensation awards are as follows:

NU	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012 [1]
Compensation Expense	$ 24.6	$ 27.0	$ 25.8
Future Income Tax Benefit	10.3	10.7	10.2

	For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Compensation Expense	$ 8.1	$ 7.4	$ 3.0	$ 1.3	$ 6.8	$ 7.5	$ 2.3	$ 1.3	$ 4.8	$ 7.4	$ 1.8	$ 1.0
Future Income Tax Benefit	3.4	3.1	1.3	0.5	2.7	3.0	0.9	0.5	1.9	2.9	0.7	0.4

(1) NSTAR amounts were included in NU beginning April 10, 2012.

As of December 31, 2014, there was $15.7 million of total unrecognized compensation expense related to nonvested share-based awards for NU, $6.1 million for CL&P, $4.3 million for NSTAR Electric, $2 million for PSNH and $1 million for WMECO. This cost is expected to be recognized ratably over a weighted-average period of 1.65 years for NU, 1.68 years for CL&P, 1.69 years for NSTAR Electric, 1.71 years for PSNH and 1.68 years for WMECO.

For the years ended December 31, 2014 and 2012, additional tax benefits totaling $9.5 million and $8.5 million increased cash flows from financing activities. For the year ended December 31, 2013, additional tax benefits totaling $5.5 million decreased cash flows from financing activities.

Stock Options: Stock options were granted under the NU and NSTAR incentive plans. Options currently outstanding expire ten years from the date of grant and are fully vested. The weighted average remaining contractual lives for the options outstanding as of December 31, 2014 is 4.3 years. A summary of stock option transactions is as follows:

	Options	Weighted Average Exercise Price	Intrinsic Value (Millions)
Outstanding and Exercisable - January 1, 2012	47,374	$ 18.78	
Converted NSTAR Options upon Merger	2,664,894	$ 23.99	
Exercised	(1,166,511)	$ 22.53	$ 18.7
Outstanding and Exercisable - December 31, 2012	1,545,757	$ 24.92	
Exercised	(324,382)	$ 20.97	$ 6.7
Outstanding and Exercisable - December 31, 2013	1,221,375	$ 25.97	
Exercised	(869,759)	$ 25.68	$ 16.4
Outstanding and Exercisable - December 31, 2014	351,616	$ 26.69	$ 9.4

Cash received for options exercised during the year ended December 31, 2014 totaled $22.3 million. The tax benefit realized from stock options exercised totaled $6.6 million for the year ended December 31, 2014.

Employee Share Purchase Plan: NU maintains an ESPP for eligible employees, which allows for NU common shares to be purchased by employees at the end of successive six-month offering periods at 95 percent of the closing market price on the last day of each six-month period. Employees are permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the offering period up to a specified limit. The ESPP qualifies as a non-compensatory plan under accounting guidance for share-based payments, and no compensation expense is recorded for ESPP purchases.

During 2014, employees purchased 40,779 shares at discounted prices of $41.61 and $41.71. Employees purchased 39,526 shares in 2013 at discounted prices of $38.69 and $42.19. As of December 31, 2014 and 2013, 776,975 and 817,754 shares, respectively, remained available for future issuance under the ESPP.

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards. The Company generally settles stock option exercises and fully vested RSUs and performance shares with either the issuance of new common shares or the issuance of common shares purchased in the open market.

D. Other Retirement Benefits

NU provides benefits for retirement and other benefits for certain current and past company officers of NU, including CL&P, PSNH and WMECO. These benefits are accounted for on an accrual basis and expensed over the service lives of the employees. The actuarially-determined liability for these benefits, which is included in Other Long-Term Liabilities on the balance sheets, as well as the related expense, are as follows:

NU	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012
Actuarially-Determined Liability	$ 57.5	$ 51.3	$ 54.6
Other Retirement Benefits Expense	4.5	4.4	4.7

	For the Years Ended December 31,									
	2014				2013			2012		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Actuarially-Determined Liability	$ 0.4	$ -	$ 2.6	$ 0.2	$ 0.4	$ 2.3	$ 0.1	$ 0.4	$ 2.5	$ 0.2
Other Retirement Benefits Expense	2.1	0.3	0.9	0.4	2.5	1.0	0.5	2.6	1.0	0.5

10. INCOME TAXES

The components of income tax expense are as follows:

NU	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012 [1]
Current Income Taxes:			
Federal	$ 4.4	$ 8.8	$ (30.9)
State	24.5	(9.4)	17.6
Total Current	28.9	(0.6)	(13.3)
Deferred Income Taxes, Net:			
Federal	406.8	386.2	291.3
State	36.5	45.4	0.8
Total Deferred	443.3	431.6	292.1
Investment Tax Credits, Net	(3.9)	(4.1)	(3.9)
Income Tax Expense	$ 468.3	$ 426.9	$ 274.9

[1] NSTAR amounts were included in NU beginning April 10, 2012.

	For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Current Income Taxes:												
Federal	$ (0.2)	$ 75.0	$ (22.6)	$ 1.9	$ 20.1	$ 95.8	$ (8.2)	$ (53.4)	$ (47.8)	$ 93.5	$ (0.9)	$ (24.7)
State	4.3	20.2	(0.1)	1.8	(6.7)	29.6	3.6	4.2	3.1	27.6	3.4	3.4
Total Current	4.1	95.2	(22.7)	3.7	13.4	125.4	(4.6)	(49.2)	(44.7)	121.1	2.5	(21.3)
Deferred Income Taxes, Net:												
Federal	138.0	88.0	79.6	28.1	114.9	49.8	64.5	84.7	141.5	11.4	46.5	51.2
State	(7.1)	20.1	15.2	6.0	15.1	(1.0)	11.2	2.3	(0.5)	(7.1)	12.0	2.7
Total Deferred	130.9	108.1	94.8	34.1	130.0	48.8	75.7	87.0	141.0	4.3	58.5	53.9
Investment Tax Credits, Net	(1.5)	(1.3)	-	(0.5)	(1.7)	(1.3)	-	(0.4)	(1.9)	(1.4)	-	(0.5)
Income Tax Expense	$ 133.5	$ 202.0	$ 72.1	$ 37.3	$ 141.7	$ 172.9	$ 71.1	$ 37.4	$ 94.4	$ 124.0	$ 61.0	$ 32.1

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

NU	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	2014	2013	2012 [1]
Income Before Income Tax Expense	$ 1,295.4	$ 1,220.6	$ 808.0
Statutory Federal Income Tax Expense at 35%	453.4	427.2	282.8
Tax Effect of Differences:			
Depreciation	(5.6)	(7.4)	(10.8)
Investment Tax Credit Amortization	(3.9)	(4.1)	(3.9)
Other Federal Tax Credits	(3.5)	(3.7)	(3.8)
State Income Taxes, Net of Federal Impact	42.5	27.6	4.4
Dividends on ESOP	(8.0)	(8.0)	(6.4)
Tax Asset Valuation Allowance/Reserve Adjustments	(2.9)	(4.3)	7.6
Other, Net	(3.7)	(0.4)	5.0
Income Tax Expense	$ 468.3	$ 426.9	$ 274.9
Effective Tax Rate	36.2%	35.0%	34.0%

[1] NSTAR amounts were included in NU beginning April 10, 2012.

	For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars, except percentages)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Income Before Income Tax Expense	$ 421.2	$ 505.1	$ 186.1	$ 95.1	$ 421.1	$ 441.4	$ 182.5	$ 97.8	$ 304.2	$ 314.2	$ 157.9	$ 86.6
Statutory Federal Income Tax Expense at 35%	147.4	176.8	65.1	33.3	147.4	154.5	63.9	34.2	106.5	110.0	55.3	30.3
Tax Effect of Differences:												
Depreciation	(3.6)	(1.3)	0.3	(0.2)	(7.0)	0.1	0.6	-	(9.0)	-	(0.3)	0.2
Investment Tax Credit Amortization	(1.5)	(1.3)	-	(0.5)	(1.7)	(1.3)	-	(0.4)	(1.9)	(1.4)	-	(0.5)
Other Federal Tax Credits	-	-	(3.5)	-	-	-	(3.7)	-	-	-	(3.8)	-
State Income Taxes, Net of Federal Impact	4.4	26.2	9.8	5.0	5.0	18.6	9.6	4.2	0.1	13.4	10.0	4.0
Tax Asset Valuation Allowance/ Reserve Adjustments	(6.3)	-	-	-	0.4	-	-	-	1.6	-	-	-
Other, Net	(6.9)	1.6	0.4	(0.3)	(2.4)	1.0	0.7	(0.6)	(2.9)	2.0	(0.2)	(1.9)
Income Tax Expense	$ 133.5	$ 202.0	$ 72.1	$ 37.3	$ 141.7	$ 172.9	$ 71.1	$ 37.4	$ 94.4	$ 124.0	$ 61.0	$ 32.1
Effective Tax Rate	31.7%	40.0%	38.7%	39.2%	33.6%	39.2%	39.0%	38.2%	31.0%	39.5%	38.6%	37.1%

NU, CL&P, NSTAR Electric, PSNH and WMECO file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Deferred tax assets and liabilities are recognized for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting authoritative literature. The tax effects of temporary differences that give rise to the net accumulated deferred income tax obligations are as follows:

NU	As of December 31,	
(Millions of Dollars)	2014	2013
Deferred Tax Assets:		
Employee Benefits	$ 632.2	$ 435.2
Derivative Liabilities	199.6	272.9
Regulatory Deferrals - Liabilities	366.7	272.7
Allowance for Uncollectible Accounts	60.5	65.0
Tax Effect - Tax Regulatory Liabilities	10.0	16.2
Federal Net Operating Loss Carryforwards	59.1	158.0
Purchase Accounting Adjustment	126.2	132.8
Other	198.7	230.6
Total Deferred Tax Assets	1,653.0	1,583.4
Less: Valuation Allowance	5.1	24.3
Net Deferred Tax Assets	$ 1,647.9	$ 1,559.1
Deferred Tax Liabilities:		
Accelerated Depreciation and Other Plant-Related Differences	$ 4,215.9	$ 3,806.5
Property Tax Accruals	109.6	95.1
Regulatory Amounts:		
Regulatory Deferrals - Assets	1,277.9	1,146.7
Tax Effect - Tax Regulatory Assets	240.2	248.2
Goodwill Regulatory Asset - 1999 Merger	203.2	211.5
Derivative Assets	32.6	30.1
Other	196.3	157.1
Total Deferred Tax Liabilities	$ 6,275.7	$ 5,695.2

(Millions of Dollars)	As of December 31, 2014 CL&P	2014 NSTAR Electric	2014 PSNH	2014 WMECO	2013 CL&P	2013 NSTAR Electric	2013 PSNH	2013 WMECO
Deferred Tax Assets:								
Employee Benefits	$ 129.0	$ 39.9	$ 46.8	$ 9.2	$ 56.0	$ 38.3	$ 15.5	$ (1.8)
Derivative Liabilities	193.0	1.8	-	-	272.4	3.3	-	(2.9)
Regulatory Deferrals - Liabilities	73.9	181.3	46.5	11.4	61.5	114.7	40.9	1.0
Allowance for Uncollectible Accounts	32.3	13.8	3.2	3.8	31.2	15.4	3.1	3.3
Tax Effect - Tax Regulatory Liabilities	3.1	1.8	2.1	2.5	4.7	5.4	2.1	1.6
Federal Net Operating Loss Carryforwards	-	-	32.1	4.5	51.0	-	56.6	18.6
Other	53.8	19.9	48.9	4.9	75.3	31.3	40.3	8.3
Total Deferred Tax Assets	485.1	258.5	179.6	36.3	552.1	208.4	158.5	28.1
Less: Valuation Allowance	4.0	-	-	-	23.1	-	-	-
Net Deferred Tax Assets	$ 481.1	$ 258.5	$ 179.6	$ 36.3	$ 529.0	$ 208.4	$ 158.5	$ 28.1
Deferred Tax Liabilities:								
Accelerated Depreciation and Other Plant-Related Differences	$ 1,378.6	$ 1,296.9	$ 596.6	$ 385.8	$ 1,238.1	$ 1,179.4	$ 526.6	$ 361.1
Property Tax Accruals	58.1	25.0	7.4	12.8	49.3	25.3	7.1	5.9
Regulatory Amounts:								
Regulatory Deferrals - Assets	502.3	276.0	147.6	60.4	550.4	276.2	109.3	49.3
Tax Effect - Tax Regulatory Assets	166.9	35.5	15.9	9.3	160.1	36.0	16.3	18.2
Goodwill Regulatory Asset - 1999 Merger	-	174.4	-	-	-	181.6	-	-
Derivative Assets	32.6	-	-	-	29.0	0.5	-	-
Other	19.4	33.5	35.6	2.8	20.6	26.4	28.0	3.6
Total Deferred Tax Liabilities	$ 2,157.9	$ 1,841.3	$ 803.1	$ 471.1	$ 2,047.5	$ 1,725.4	$ 687.3	$ 438.1

Carryforwards: The following tables provide the amounts and expiration dates of state tax credit and loss carryforwards and federal tax credit and net operating loss carryforwards:

	As of December 31, 2014					
(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO	Expiration Range
Federal Net Operating Loss	$ 168.8	$ -	$ -	$ 91.8	$ 12.7	2031 - 2032
Federal Tax Credit	16.3	0.1	0.2	11.1	-	2031 - 2034
Federal Charitable Contribution	19.4	-	-	-	-	2016 - 2018
State Tax Credit	99.7	71.0	-	-	-	2014 - 2019
State Loss Carryforwards	40.6	-	-	-	-	2014 - 2034
State Charitable Contribution	2.1	-	-	-	-	2015 - 2018

	As of December 31, 2013					
(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO	Expiration Range
Federal Net Operating Loss	$ 451.3	$ 145.8	$ -	$ 161.8	$ 53.3	2031 - 2032
Federal Tax Credit	8.0	-	-	7.6	-	2031 - 2033
Federal Charitable Contribution	33.7	-	-	-	-	2015 - 2017
State Tax Credit	104.7	86.8	-	-	-	2013 - 2018
State Loss Carryforwards	12.1	-	-	-	-	2013 - 2015
State Charitable Contribution	1.0	-	-	-	-	2015

In 2014, the Company recorded a reduction to its state credit carryforwards of $11 million (CL&P $10.1 million), net of tax, as a result of an update to reflect the amounts expired. Further, the Company decreased its valuation allowance reserve for state credits by $19.2 million at CL&P, net of tax, to reflect an update for expired state credits and latest estimate of usage.

For 2014, state credit and state loss carryforwards have been partially reserved by a valuation allowance of $4.4 million (net of federal income tax). For 2013, state credit and state loss carryforwards have been partially reserved by a valuation allowance of $23.7 million (net of federal income tax).

Unrecognized Tax Benefits: A reconciliation of the activity in unrecognized tax benefits, all of which would impact the effective tax rate if recognized, is as follows:

(Millions of Dollars)	NU	CL&P
Balance as of January 1, 2012	$ 73.5	$ 46.5
Gross Increases - Current Year	10.3	2.5
Gross Increases - Prior Year	0.1	-
Gross Decreases - Prior Year	(0.8)	-
Balance as of December 31, 2012	83.1	49.0
Gross Increases - Current Year	8.2	2.1
Gross Decreases - Prior Year	(1.1)	(0.3)
Settlements	(49.8)	(39.4)
Lapse of Statute of Limitations	(2.2)	-
Balance as of December 31, 2013	38.2	11.4

Gross Increases - Current Year	9.3	2.7
Gross Increases - Prior Year	0.3	0.2
Lapse of Statute of Limitations	(1.6)	-
Balance as of December 31, 2014	$ 46.2	$ 14.3

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense on the statements of income. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the statements of income. No penalties have been recorded. The amount of interest expense/(income) on uncertain tax positions recognized and the related accrued interest payable/(receivable) are as follows:

Other Interest Expense/(Income)	For the Years Ended December 31, 2014	2013	2012
(Millions of Dollars)			
NU [1]	$ 0.4	$ (8.6)	$ 3.1
CL&P	-	(4.0)	1.3

Accrued Interest Expense	As of December 31, 2014	2013
(Millions of Dollars)		
NU	$ 1.9	$ 1.5
CL&P	-	-

[1] NSTAR amounts were included in NU beginning April 10, 2012.

Tax Positions: During 2014, NU did not resolve any of its uncertain tax positions.

During 2013, NU received a Final Determination from the Connecticut Department of Revenue Services (DRS) that concluded its audit of NU's Connecticut income tax returns for the years 2005 through 2008. The DRS Determination resulted in total NU and CL&P after-tax benefits of $13.6 million and $6.9 million, respectively, that included a reduction in NU and CL&P pre-tax interest expense of $8.7 million and $4 million, or $5.2 million and $2.4 million after-tax, respectively. Further, the income tax expense impact resulted in a tax benefit to NU and CL&P of $8.4 million and $4.5 million after-tax, respectively.

Open Tax Years: The following table summarizes NU, CL&P, NSTAR Electric, PSNH and WMECO's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2014:

Description	Tax Years
Federal	2014
Connecticut	2011 – 2014
Massachusetts	2011 – 2014
New Hampshire	2011 – 2014

NU estimates that during the next twelve months, differences of a non-timing nature could be resolved, resulting in a zero to $2 million decrease in unrecognized tax benefits by NU. These estimated changes are not expected to have a material impact on the earnings of NU. Other companies' impacts are not expected to be material.

2014 Federal Legislation: On December 19, 2014, the "Tax Increase Prevention Act of 2014" became law, which extended the accelerated deduction of depreciation to businesses through 2014. This extended stimulus provides NU with cash flow benefits of approximately $200 million (approximately $70 million at CL&P, $50 million at NSTAR Electric, $35 million at PSNH, and $15 million at WMECO) in 2015.

2013 Federal Legislation: On January 2, 2013, the "American Taxpayer Relief Act of 2012" became law, which extended the accelerated deduction of depreciation to businesses through 2013. This extended stimulus provided NU with cash flow benefits of approximately $300 million (approximately $95 million at CL&P, $85 million at NSTAR Electric, $35 million at PSNH, and $50 million at WMECO).

On September 13, 2013, the Internal Revenue Service issued final Tangible Property regulations that are meant to simplify, clarify and make more administrable previously issued guidance. NU is in compliance with the new regulations, but continues to evaluate several new potential elections.

2013 Massachusetts: On July 24, 2013, Massachusetts enacted a law that changed the income tax rate applicable to utility companies effective January 1, 2014, from 6.5 percent to 8 percent. The tax law change required NU to remeasure its accumulated deferred income taxes and resulted in NU increasing its deferred tax liability with an offsetting regulatory asset of approximately $61 million at its utility companies ($46.3 million at NSTAR Electric and $9.8 million at WMECO).

11. COMMITMENTS AND CONTINGENCIES

A. Environmental Matters

General: NU, CL&P, NSTAR Electric, PSNH and WMECO are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. NU, CL&P, NSTAR Electric, PSNH and WMECO have an active environmental auditing and training program and believe that they are substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring.

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of NU, CL&P, NSTAR Electric, PSNH and WMECO's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities included in Other Current Liabilities and Other Long-Term Liabilities on the balance sheets represent management's best estimate of the liability for environmental costs, and take into consideration site assessment, remediation and long-term monitoring costs. The environmental liability also takes into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate previously contaminated sites and any other infrequent and non-recurring clean-up costs. A reconciliation of the activity in the environmental reserves is as follows:

(Millions of Dollars)	NU	CL&P	NSTAR Electric	PSNH	WMECO
Balance as of January 1, 2013	$ 39.4	$ 3.7	$ 1.7	$ 4.9	$ 0.6
Additions	3.5	0.2	0.2	1.0	-
Payments/Reductions	(7.5)	(0.5)	(0.7)	(0.5)	(0.2)
Balance as of December 31, 2013	35.4	3.4	1.2	5.4	0.4
Additions	12.7	1.0	-	0.1	0.2
Payments/Reductions	(4.8)	(0.6)	(0.1)	(0.3)	(0.1)
Balance as of December 31, 2014	$ 43.3	$ 3.8	$ 1.1	$ 5.2	$ 0.5

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserves include sites at different stages of discovery and remediation and do not include any unasserted claims.

It is possible that new information or future developments could require a reassessment of the potential exposure to related environmental matters. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

The number of environmental sites and reserves related to these sites for which remediation or long-term monitoring, preliminary site work or site assessment are being performed are as follows:

	As of December 31, 2014		As of December 31, 2013	
	Number of Sites	Reserve (in millions)	Number of Sites	Reserve (in millions)
NU	65	$ 43.3	68	$ 35.4
CL&P	16	3.8	18	3.4
NSTAR Electric	13	1.1	12	1.2
PSNH	13	5.2	15	5.4
WMECO	4	0.5	5	0.4

Included in the NU number of sites and reserve amounts above are former MGP sites that were operated several decades ago and manufactured gas from coal and other processes, which resulted in certain by-products remaining in the environment that may pose a potential risk to human health and the environment. The reserve balance related to these former MGP sites was $38.8 million and $31.4 million as of December 31, 2014 and 2013, respectively, and relates primarily to the natural gas business segment. The increase in the reserve balance for the MGP sites was due to the completion of the site assessment at three sites. The assessments provided new information related to the extent and nature of the contamination and the costs of required remediation.

As of December 31, 2014, for 5 environmental sites (1 for CL&P, and 1 for WMECO) that are included in the Company's reserve for environmental costs, the information known and nature of the remediation options at those sites allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2014, $17.7 million ($1 million for CL&P and $0.3 million for WMECO) had been accrued as a liability for these sites, which represent management's best estimates of the liabilities for environmental costs. These amounts are the best estimates with estimated ranges of additional losses from zero to $24 million.

As of December 31, 2014, for 15 environmental sites (3 for CL&P, 3 for NSTAR Electric and 2 for PSNH) that are included in the Company's reserve for environmental costs, management cannot reasonably estimate the exposure to loss in excess of the reserve, or range of loss, as these sites are under investigation and/or there is significant uncertainty as to what remedial actions, if any, the Company may be required to undertake. As of December 31, 2014, $13.4 million ($1.4 million for CL&P, $0.2 million for PSNH) had been accrued as a liability for these sites. As of December 31, 2014, for the remaining 45 environmental sites (12 for CL&P, 10 for NSTAR Electric, 11 for PSNH, and 3 for WMECO) that are included in the Company's reserve for environmental costs, the $12.2 million accrual ($1.4 million for CL&P, $1.1 million for NSTAR Electric, $5 million for PSNH, and $0.2 million for WMECO) represents management's best estimate of the liability and no additional loss is anticipated.

CERCLA: Of the total environmental sites, 9 sites (1 for CL&P, 3 for NSTAR Electric and 3 for PSNH) are superfund sites under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and its amendments or state equivalents for which the Company has been notified that it is a potentially responsible party but for which the site assessment and remediation are not being managed by the Company. As of December 31, 2014, a liability of $0.7 million accrued on these sites represents management's best estimate of its potential remediation costs with respect to these superfund sites.

Environmental Rate Recovery: PSNH, NSTAR Gas and Yankee Gas have rate recovery mechanisms for MGP related environmental costs. CL&P recovers a certain level of environmental costs currently in rates but does not have an environmental cost recovery tracking mechanism. Accordingly, changes in CL&P's environmental reserves impact CL&P's Net Income. NSTAR Electric and WMECO do not have a separate regulatory mechanism to recover environmental costs from its customers, and changes in NSTAR Electric's and WMECO's environmental reserves impact Net Income.

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant long-term contractual arrangements as of December 31, 2014 are as follows:

NU *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Supply and Stranded Cost	$ 196.6	$ 169.2	$ 101.9	$ 65.3	$ 38.1	$ 82.4	$ 653.5
Renewable Energy	204.3	240.5	239.6	204.2	202.9	1,994.6	3,086.1
Peaker CfDs	26.3	25.4	10.5	-	-	-	62.2
Natural Gas Procurement	133.7	116.3	45.6	31.9	25.8	85.1	438.4
Coal, Wood and Other	99.0	25.2	5.0	5.0	1.9	15.0	151.1
Transmission Support Commitments	25.9	21.6	19.0	21.2	21.3	21.3	130.3
Total	$ 685.8	$ 598.2	$ 421.6	$ 327.6	$ 290.0	$ 2,198.4	$ 4,521.6

CL&P *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Supply and Stranded Cost	$ 134.3	$ 136.8	$ 79.0	$ 42.0	$ 25.0	$ 43.6	$ 460.7
Renewable Energy	61.2	70.3	71.3	72.1	72.1	715.9	1,062.9
Peaker CfDs	26.3	25.4	10.5	-	-	-	62.2
Transmission Support Commitments	10.2	8.5	7.5	8.4	8.4	8.4	51.4
Yankee Billings	1.4	0.8	0.8	0.9	0.9	11.8	16.6
Total	$ 233.4	$ 241.8	$ 169.1	$ 123.4	$ 106.4	$ 779.7	$ 1,653.8

NSTAR Electric *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Supply and Stranded Cost	$ 34.3	$ 14.1	$ 4.8	$ 5.5	$ 5.5	$ 31.4	$ 95.6
Renewable Energy	85.4	99.9	96.9	59.6	57.7	319.8	719.3
Transmission Support Commitments	8.1	6.7	5.9	6.6	6.6	6.6	40.5
Yankee Billings	0.5	0.3	0.3	0.3	0.3	4.0	5.7
Total	$ 128.3	$ 121.0	$ 107.9	$ 72.0	$ 70.1	$ 361.8	$ 861.1

PSNH *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Supply and Stranded Cost	$ 28.0	$ 18.3	$ 18.1	$ 17.8	$ 7.6	$ 7.4	$ 97.2
Renewable Energy	57.7	67.9	69.0	70.1	70.7	932.4	1,267.8
Coal, Wood and Other	99.0	25.2	5.0	5.0	1.9	15.0	151.1
Transmission Support Commitments	5.5	4.6	4.0	4.5	4.5	4.5	27.6
Yankee Billings	0.4	0.3	0.3	0.3	0.3	4.7	6.3
Total	$ 190.6	$ 116.3	$ 96.4	$ 97.7	$ 85.0	$ 964.0	$ 1,550.0

WMECO *(Millions of Dollars)*	2015	2016	2017	2018	2019	Thereafter	Total
Renewable Energy	$ -	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 26.5	$ 36.1
Transmission Support Commitments	2.1	1.8	1.6	1.7	1.8	1.8	10.8
Yankee Billings	0.3	0.2	0.2	0.2	0.2	3.0	4.1
Total	$ 2.4	$ 4.4	$ 4.2	$ 4.3	$ 4.4	$ 31.3	$ 51.0

Supply and Stranded Cost: CL&P, NSTAR Electric and PSNH have various IPP contracts or purchase obligations for electricity, including payment obligations resulting from the buydown of electricity purchase contracts. Such contracts extend through 2024 for CL&P, 2030 for NSTAR Electric and 2023 for PSNH.

In addition, CL&P, along with UI, has four capacity CfDs for a total of approximately 787 MW of capacity consisting of three generation projects and one demand response project. The capacity CfDs extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the capacity market prices received by the generation facilities in the ISO-NE capacity markets. CL&P has a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

The contractual obligations table does not include CL&P's SS or LRS, or NSTAR Electric's or WMECO's default service contracts, the amounts of which vary with customers' energy needs. The contractual obligations table also does not include PSNH's short-term power supply management.

Renewable Energy: Renewable energy contracts include non-cancellable commitments under contracts of CL&P, NSTAR Electric, PSNH, and WMECO for the purchase of energy and capacity from renewable energy facilities. Such contracts extend through 2035 for CL&P, 2030 for NSTAR Electric, 2033 for PSNH and 2030 for WMECO.

The contractual obligations table does not include long-term commitments signed by CL&P, NSTAR Electric and WMECO, as required by the PURA and DPU, for the purchase of renewable energy and related products that are contingent on the future construction of energy facilities.

Peaker CfDs: In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the PURA (Peaker CfDs). These units have a total of approximately 500 MW of peaking capacity. As directed by the PURA, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the generation facility owner the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from or refunded to CL&P's customers.

Natural Gas Procurement: NU's natural gas distribution businesses have long-term contracts for the purchase, transportation and storage of natural gas in the normal course of business as part of its portfolio of supplies. These contracts extend through 2029.

Coal, Wood and Other: PSNH has entered into various arrangements for the purchase of coal, wood and the transportation services for fuel supply for its electric generating assets. Also included in the table above is a contract for capacity on the Portland Natural Gas Transmission System (PNGTS) pipeline that extends through 2018. The costs on this contract of $11.4 million are not recoverable from customers.

Transmission Support Commitments: Along with other New England utilities, CL&P, NSTAR Electric, PSNH and WMECO entered into agreements in 1985 to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, NSTAR Electric, PSNH and WMECO are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities.

The total costs incurred under these agreements were as follows:

NU	For the Years Ended December 31,		
(Millions of Dollars)	2014	2013	2012 [1]
Supply and Stranded Cost	$ 99.2	$ 141.0	$ 216.8
Renewable Energy	114.4	91.3	48.7
Peaker CfDs	18.1	51.9	59.3
Natural Gas Procurement	482.5	349.8	243.1
Coal, Wood and Other	120.5	112.6	105.2
Transmission Support Commitments	25.0	24.9	24.8

	For the Years Ended December 31,											
	2014				2013				2012			
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO	CL&P	NSTAR Electric	PSNH	WMECO
Supply and Stranded Cost	$ 63.0	$ 7.0	$ 26.0	$ 3.2	$ 77.6	$ 32.4	$ 29.0	$ 2.0	$ 158.2	$ 36.3	$ 30.5	$ 0.9
Renewable Energy	0.7	87.4	26.3	-	-	84.9	6.4	-	-	60.2	4.1	-
Peaker CfDs	18.1	-	-	-	51.9	-	-	-	59.3	-	-	-
Coal, Wood and Other	-	-	120.5	-	-	-	112.6	-	-	-	105.2	-
Transmission Support Commitments	9.9	7.7	5.3	2.1	9.8	7.7	5.3	2.1	9.6	7.6	5.2	2.0

(1) NSTAR amounts were included in NU beginning April 10, 2012.

C. Contractual Obligations - Yankee Companies

CL&P, NSTAR Electric, PSNH and WMECO have decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, NSTAR Electric, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates.

CL&P, NSTAR Electric, PSNH and WMECO's percentage share of the obligations to support the Yankee Companies under FERC-approved rate tariffs is the same as their respective ownership percentages in the Yankee Companies. For further information on the ownership percentages, see Note 1J, "Summary of Significant Accounting Policies - Equity Method Investments," to the financial statements.

The Yankee Companies have collected or are currently collecting amounts that management believes are adequate to recover the remaining decommissioning and closure cost estimates for the respective plants. Management believes CL&P, NSTAR Electric and WMECO will recover their shares of these decommissioning and closure obligations from their customers. PSNH has already recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation:
DOE Phase I Damages – In 1998, the Yankee Companies filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE (DOE Phase I Damages). Phase I covered damages for the period 1998 through 2002. Following multiple appeals and cross-appeals, in December 2012, the judgment awarding CYAPC $39.6 million, YAEC $38.3 million and MYAPC $81.7 million became final.

In January 2013, the proceeds from the DOE Phase I Damages Claim were received by the Yankee Companies and transferred to each Yankee Company's respective decommissioning trust. As a result of NU's consolidation of CYAPC and YAEC, the financial statements reflected an increase of $77.9 million in marketable securities for CYAPC and YAEC's Phase I Damage awards that were invested in the nuclear decommissioning trusts in 2013.

In June 2013, FERC approved CYAPC, YAEC and MYAPC to reduce rates in their wholesale power contracts through the application of the DOE proceeds for the benefit of customers. Changes to the terms of the wholesale power contracts became effective on July 1, 2013. In accordance with the FERC order, CL&P, NSTAR Electric, PSNH and WMECO began receiving the benefit of the DOE proceeds, and the benefits have been passed on to customers.

On September 17, 2014, in accordance with the MYAPC refund plan, MYAPC returned a portion of the DOE Phase I Damages proceeds to the member companies, including CL&P, NSTAR Electric, PSNH, and WMECO, in the amount of \$3.2 million, \$1.1 million, \$1.4 million and \$0.8 million, respectively. These amounts reduced receivables at CL&P, NSTAR Electric, PSNH and WMECO.

DOE Phase II Damages - In December 2007, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred related to the alleged failure of the DOE to provide for a permanent facility to store spent nuclear fuel generated in years 2001 through 2008 for CYAPC and YAEC and from 2002 through 2008 for MYAPC (DOE Phase II Damages). In November 2013, the court issued a final judgment awarding CYAPC \$126.3 million, YAEC \$73.3 million, and MYAPC \$35.8 million. On January 14, 2014, the Yankee Companies received a letter from the U.S. Department of Justice stating that the DOE will not appeal the court's final judgment.

In March and April 2014, CYAPC, YAEC and MYAPC received payment of \$126.3 million, \$73.3 million and \$35.8 million, respectively, of the DOE Phase II Damages proceeds and made the required informational filing with FERC in accordance with the process and methodology outlined in the 2013 FERC order. The Yankee Companies returned the DOE Phase II Damages proceeds to the member companies, including CL&P, NSTAR Electric, PSNH, and WMECO, for the benefit of their respective customers, on June 1, 2014.

As of December 31, 2014, CL&P's refund obligation to customers of \$65.4 million was recorded as an offset to the deferred storm restoration costs regulatory asset, as directed by PURA. NSTAR Electric's, PSNH's and WMECO's refund obligation to customers of \$29.1 million, \$13.1 million and \$18.1 million, respectively, was recorded as a regulatory liability in each company's respective regulatory tracker mechanisms. Refunds to customers for these DOE proceeds began in the third quarter of 2014. For further information, see Note 2, "Regulatory Accounting," to the financial statements.

DOE Phase III Damages – In August 2013, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years 2009 through 2012. The presiding judge issued a Pre-Trial Scheduling Order on September 3, 2014 that set the case for trial from June 30 to July 2, 2015.

D. Guarantees and Indemnifications

NU parent provides credit assurances on behalf of its subsidiaries, including CL&P, NSTAR Electric, PSNH and WMECO, in the form of guarantees in the normal course of business.

NU provided guarantees and various indemnifications on behalf of external parties as a result of the sales of former subsidiaries of NU Enterprises and the termination of an unregulated business, with maximum exposures either not specified or not material.

NU also issued a guaranty under which, beginning at the time the Northern Pass Transmission line goes into commercial operation, NU will guarantee the financial obligations of NPT under the TSA in an amount not to exceed \$25 million. NU's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

Management does not anticipate a material impact to Net Income as a result of these various guarantees and indemnifications.

The following table summarizes NU's guarantees of its subsidiaries, including CL&P, NSTAR Electric, PSNH and WMECO, as of December 31, 2014:

Subsidiary	Description	Maximum Exposure (in millions)		Expiration Dates
Various	Surety Bonds [1]	\$	60.0	2015 - 2016
NUSCO and Rocky River Realty Company	Lease Payments for Vehicles and Real Estate	\$	14.4	2019 and 2024

(1) Surety bond expiration dates reflect termination dates, the majority of which will be renewed or extended. Certain surety bonds contain credit ratings triggers that would require NU parent to post collateral in the event that the unsecured debt credit ratings of NU are downgraded.

E. FERC Base ROE Complaints

Beginning in 2011, several New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (the "Complainants") jointly filed three separate complaints at FERC. In the first complaint, filed in 2011, the Complainants alleged that the NETOs' base ROE of 11.14 percent that was utilized since 2006 was unjust and unreasonable, asserted that the rate was excessive due to changes in the capital markets, and sought an order to reduce it prospectively from the date of the final FERC order and for the 15-month period beginning October 1, 2011 to December 31, 2012 (the "first complaint refund period"). In the pursuant second and third complaints, filed in 2012 and 2014, respectively, the Complainants challenged the NETOs' base ROE and sought refunds for the 15-month periods beginning December 27, 2012 and July 31, 2014, respectively.

In 2014, the FERC determined that the base ROE should be set at 10.57 percent for the first complaint refund period and that a utility's total or maximum ROE should not exceed the top of the new zone of reasonableness (7.03 percent to 11.74 percent). The FERC ordered the NETOs to provide refunds to customers for the first complaint refund period and set the new base ROE of 10.57 percent prospectively from October 16, 2014. In late 2014, the NETOs made a compliance filing, and began refunding amounts from the first complaint period, inclusive of incentive ROE adders that exceeded the 11.74 percent as compared to the total company transmission ROE. Complainants have challenged the compliance filing.

As a result of the actions taken by the FERC and other developments in this matter, NU recorded reserves in 2013 and 2014 to recognize the potential financial impacts of the first and second complaints. The Company is unable to determine any amount related to the third complaint. The following is a summary of the cumulative pre-tax reserves (excluding interest) established by the Company in 2013 and 2014:

	NU For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total
1st Complaint - Base ROE	$ 23.7	$ 1.2	$ 24.9
2nd Complaint - Base ROE	-	27.4	27.4
Incentive ROE (1st and 2nd Complaint)	-	8.4	8.4
Cumulative Reserve	$ 23.7	$ 37.0	$ 60.7

	CL&P For the Years Ended December 31,			NSTAR Electric For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total	2013	2014	Total
1st Complaint - Base ROE	$ 12.8	$ 0.5	$ 13.3	$ 5.7	$ 0.4	$ 6.1
2nd Complaint - Base ROE	-	13.5	13.5	-	7.5	7.5
Incentive ROE (1st and 2nd Complaint)	-	6.7	6.7	-	-	-
Cumulative Reserve	$ 12.8	$ 20.7	$ 33.5	$ 5.7	$ 7.9	$ 13.6

	PSNH For the Years Ended December 31,			WMECO For the Years Ended December 31,		
(Millions of Dollars)	2013	2014	Total	2013	2014	Total
1st Complaint - Base ROE	$ 2.3	$ 0.1	$ 2.4	$ 2.9	$ 0.2	$ 3.1
2nd Complaint - Base ROE	-	2.7	2.7	-	3.7	3.7
Incentive ROE (1st and 2nd Complaint)	-	-	-	-	1.7	1.7
Cumulative Reserve	$ 2.3	$ 2.8	$ 5.1	$ 2.9	$ 5.6	$ 8.5

As of December 31, 2014, the cumulative reserves above do not reflect refunds totaling $4.8 million at NU, $2.7 million at CL&P, $1 million at NSTAR Electric, $0.5 million at PSNH and $0.6 million at WMECO for the first complaint refund period.

The aggregate after-tax net charge to 2014 earnings resulting from the 2014 FERC orders totaled $22.4 million at NU, $12.4 million at CL&P, $4.9 million at NSTAR Electric, $1.7 million at PSNH and $3.4 million at WMECO. In 2013, the aggregate after-tax charge to earnings totaled $14.3 million at NU, $7.7 million at CL&P, $3.4 million at NSTAR Electric, $1.4 million at PSNH and $1.8 million at WMECO.

Although management is uncertain on the final outcome on the second and third complaints regarding the base ROE and the incentive ROE adder, management believes the current reserves established are appropriate to reflect probable and reasonably estimable refunds.

F. 2014 Comprehensive Settlement Agreement

On December 31, 2014, NSTAR Electric, NSTAR Gas and the Massachusetts Attorney General filed a comprehensive settlement agreement with the DPU. The comprehensive settlement agreement included resolution of the outstanding NSTAR Electric CPSL program filings for the periods 2006 through 2011, the NSTAR Electric and NSTAR Gas PAM and energy efficiency-related customer billing adjustments reported in 2012, and the NSTAR Electric energy efficiency program filings regarding LBR for the periods 2008 through 2011. If approved by the DPU, NSTAR Electric and NSTAR Gas will be required to refund a total of $44.7 million to their respective customers, which was included in regulatory liabilities as of December 31, 2014. Upon the DPU's approval, NSTAR Electric will adjust its regulatory liabilities, which it expects will result in a benefit of $23 million in the first quarter of 2015. Management expects a response from the DPU in the first quarter of 2015.

G. Basic Service Bad Debt Adder

In accordance with a generic 2005 DPU order, electric utilities in Massachusetts recover the energy-related portion of bad debt costs in their Basic Service rates. In 2007, NSTAR Electric filed its 2006 Basic Service reconciliation with the DPU proposing an adjustment related to the increase of its Basic Service bad debt charge-offs. The DPU issued an order approving the implementation of a revised Basic Service rate but instructed NSTAR Electric to reduce distribution rates by an amount equal to the increase in its Basic Service bad debt charge-offs. This adjustment to NSTAR Electric's distribution rates would eliminate the fully reconciling nature of the Basic Service bad debt adder.

In 2010, NSTAR Electric filed an appeal of the DPU's order with the SJC. NSTAR Electric's position was that it had fully removed the collection of energy-related bad debt costs from its distribution rates effective January 1, 2006. Therefore, no further adjustment to distribution rates was warranted. In 2012, the SJC vacated the DPU order and remanded the matter to the DPU for further review.

As of December 31, 2014, NSTAR Electric has a total deferred regulatory asset of approximately $33 million of costs associated with energy-related bad debt.

On January 7, 2015, the DPU issued an order on remand stating that NSTAR Electric had, in fact, removed energy-related bad debt costs from distribution rates effective January 1, 2006. The DPU order approved NSTAR Electric's 2005 and 2006 reconciliation filings and ordered NSTAR Electric and the Massachusetts Attorney General to collaborate on the submission of a proposal for the reconciliation of energy-related bad debt costs for the open years of 2007 through 2014 by April 7, 2015. Management expects to present a proposal to the Attorney General in the first quarter of 2015 with a decision from the DPU later in 2015.

H. Litigation and Legal Proceedings
NU, including CL&P, NSTAR Electric, PSNH and WMECO, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, and discloses matters when losses are probable but not estimable or when losses are reasonably possible. Legal costs related to the defense of loss contingencies are expensed as incurred.

12. LEASES

NU, including CL&P, NSTAR Electric, PSNH and WMECO, has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, service centers, and office space. In addition, CL&P, NSTAR Electric, PSNH and WMECO incur costs associated with leases entered into by NUSCO and Rocky River Realty Company, which are included below in their respective operating lease rental expenses and future minimum rental payments. These intercompany lease amounts are eliminated on an NU consolidated basis. The provisions of the NU, CL&P, NSTAR Electric, PSNH, and WMECO lease agreements generally contain renewal options. Certain lease agreements contain payments impacted by the commercial paper rate plus a credit spread or the consumer price index.

Operating lease rental payments charged to expense are as follows:

(Millions of Dollars)	NU [1]	CL&P	NSTAR Electric	PSNH	WMECO
2014	$ 14.3	$ 6.0	$ 7.8	$ 1.5	$ 1.2
2013	16.3	8.1	6.7	1.7	2.9
2012	14.8	8.2	6.2	2.5	3.0

[1] NSTAR amounts were included in NU beginning April 10, 2012.

Future minimum rental payments, excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 2014 are as follows:

Operating Leases *(Millions of Dollars)*	NU	CL&P	NSTAR Electric	PSNH	WMECO
2015	$ 20.1	$ 4.3	$ 10.0	$ 1.1	$ 1.2
2016	17.6	3.8	8.8	1.0	1.0
2017	14.6	2.6	7.7	0.8	0.8
2018	10.5	1.5	5.8	0.6	0.6
2019	8.6	1.1	4.7	0.5	0.6
Thereafter	22.5	4.0	10.4	1.5	2.5
Future minimum lease payments	$ 93.9	$ 17.3	$ 47.4	$ 5.5	$ 6.7

Capital Leases *(Millions of Dollars)*	NU	CL&P	PSNH
2015	$ 2.4	$ 2.0	$ 0.4
2016	2.2	1.9	0.3
2017	2.1	2.0	0.1
2018	2.1	2.0	0.1
2019	2.0	2.0	-
Thereafter	3.5	3.5	-
Future minimum lease payments	14.3	13.4	0.9
Less amount representing interest	4.9	5.0	-
Present value of future minimum lease payments	$ 9.4	$ 8.4	$ 0.9

CL&P entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not included in the tables above. However, such contracts have been included in the contractual obligations table in Note 11B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the financial statements.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock and Long-Term Debt: The fair value of CL&P's and NSTAR Electric's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of long-term debt securities is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. The fair values provided in the tables below are classified as Level 2 within the fair value hierarchy. Carrying amounts and estimated fair values are as follows:

	As of December 31,			
	2014		2013	
NU *(Millions of Dollars)*	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 153.6	$ 155.6	$ 152.7
Long-Term Debt	8,851.6	9,451.2	8,310.2	8,443.1

(Millions of Dollars)	As of December 31, 2014 CL&P Carrying Amount	CL&P Fair Value	NSTAR Electric Carrying Amount	NSTAR Electric Fair Value	PSNH Carrying Amount	PSNH Fair Value	WMECO Carrying Amount	WMECO Fair Value
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 112.0	$ 43.0	$ 41.6	$ -	$ -	$ -	$ -
Long-Term Debt	2,842.0	3,214.5	1,797.4	1,993.5	1,076.3	1,137.9	628.5	689.4

(Millions of Dollars)	As of December 31, 2013 CL&P Carrying Amount	CL&P Fair Value	NSTAR Electric Carrying Amount	NSTAR Electric Fair Value	PSNH Carrying Amount	PSNH Fair Value	WMECO Carrying Amount	WMECO Fair Value
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 110.5	$ 43.0	$ 42.2	$ -	$ -	$ -	$ -
Long-Term Debt	2,741.2	2,952.8	1,801.1	1,888.0	1,049.0	1,073.9	629.4	640.1

Derivative Instruments: Derivative instruments are carried at fair value. For further information, see Note 4, "Derivative Instruments," to the financial statements.

Other Financial Instruments: Investments in marketable securities are carried at fair value. For further information, see Note 5, "Marketable Securities," to the financial statements. The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents and special deposits, approximates their fair value due to the short-term nature of these instruments.

See Note 1H, "Summary of Significant Accounting Policies - Fair Value Measurements," for the fair value measurement policy and the fair value hierarchy.

14. ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The changes in accumulated other comprehensive income/(loss) by component, net of tax effect, is as follows:

(Millions of Dollars)	For the Year Ended December 31, 2014 Qualified Cash Flow Hedging Instruments	Unrealized Gains/(Losses) on Marketable Securities	Defined Benefit Plans	Total	For the Year Ended December 31, 2013 Qualified Cash Flow Hedging Instruments	Unrealized Gains/(Losses) on Marketable Securities	Defined Benefit Plans	Total
AOCI as of January 1st	$ (14.4)	$ 0.4	$ (32.0)	$ (46.0)	$ (16.4)	$ 1.3	$ (57.8)	$ (72.9)
OCI Before Reclassifications	-	0.3	(34.2)	(33.9)	-	(0.9)	19.4	18.5
Amounts Reclassified from AOCI	2.0	-	3.9	5.9	2.0	-	6.4	8.4
Net OCI	2.0	0.3	(30.3)	(28.0)	2.0	(0.9)	25.8	26.9
AOCI as of December 31st	$ (12.4)	$ 0.7	$ (62.3)	$ (74.0)	$ (14.4)	$ 0.4	$ (32.0)	$ (46.0)

NU's qualified cash flow hedging instruments represent interest rate swap agreements on debt issuances that were settled in prior years. The settlement amount was recorded in AOCI and is being amortized into Net Income over the term of the underlying debt instrument. CL&P, PSNH and WMECO continue to amortize interest rate swaps settled in prior years from AOCI into Interest Expense over the remaining life of the associated long-term debt, which are not material to their respective financial statements.

The tax effects of Defined Benefit Plan OCI amounts before reclassifications, which relate to actuarial gains and losses that arose during 2014, 2013 and 2012 were recognized in AOCI as net deferred tax assets of $22.3 million and $6.2 million in 2014 and 2012, respectively, and net deferred tax liabilities of $11.4 million in 2013.

The following table sets forth the amounts reclassified from AOCI by component and the impacted line item on the statements of income:

(Millions of Dollars)	For the Years Ended December 31, 2014 Amounts Reclassified from AOCI	2013 Amounts Reclassified from AOCI	2012 Amounts Reclassified from AOCI	Statements of Income Line Item Impacted
Qualified Cash Flow Hedging Instruments	$ (3.4)	$ (3.4)	$ (3.3)	Interest Expense
Tax Effect	1.4	1.4	1.3	Income Tax Expense
Qualified Cash Flow Hedging Instruments, Net of Tax	$ (2.0)	$ (2.0)	$ (2.0)	
Defined Benefit Plan Costs:				
Amortization of Actuarial Losses	$ (6.2)	$ (10.5)	$ (8.9)	Operations and Maintenance (1)
Amortization of Prior Service Cost	(0.2)	(0.2)	(0.2)	Operations and Maintenance (1)
Amortization of Transition Obligation	-	-	(0.2)	Operations and Maintenance (1)
Total Defined Benefit Plan Costs	(6.4)	(10.7)	(9.3)	
Tax Effect	2.5	4.3	3.5	Income Tax Expense
Defined Benefit Plan Costs, Net of Tax	$ (3.9)	$ (6.4)	$ (5.8)	
Total Amounts Reclassified from AOCI, Net of Tax	$ (5.9)	$ (8.4)	$ (7.8)	

(1) These amounts are included in the computation of net periodic Pension, SERP and PBOP costs. See Note 9A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," for further information.

As of December 31, 2014, it is estimated that a pre-tax amount of $3.5 million ($0.7 million for CL&P, $2 million for PSNH and $0.6 million for WMECO) will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of the interest rate swap agreements, which have been settled. In addition, it is estimated that a pre-tax amount of $6.9 million will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of Pension, SERP and PBOP costs.

15. DIVIDEND RESTRICTIONS

NU parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement.

CL&P, NSTAR Electric, PSNH and WMECO are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, NSTAR Electric, PSNH and WMECO, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from retained earnings. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas and NSTAR Gas. Such state law restrictions do not restrict payment of dividends from retained earnings or net income. Pursuant to the joint revolving credit agreement of NU, CL&P, PSNH, WMECO, Yankee Gas and NSTAR Gas, and the NSTAR Electric revolving credit agreement, each company is required to maintain consolidated total debt to total capitalization ratio of no greater than 65 percent at all times. As of December 31, 2014, all companies were in compliance with such covenant. The Retained Earnings balances subject to these restrictions were $2.4 billion for NU, $1.1 billion for CL&P, $1.5 billion for NSTAR Electric, $486.5 million for PSNH and $178.8 million for WMECO as of December 31, 2014. As of December 31, 2014, NU, CL&P, NSTAR Electric, PSNH, WMECO, Yankee Gas and NSTAR Gas were in compliance with all such provisions of the revolving credit agreements that may restrict the payment of dividends. PSNH is further required to reserve an additional amount under its FERC hydroelectric license conditions. As of December 31, 2014, $13 million of PSNH's Retained Earnings was subject to restriction under its FERC hydroelectric license conditions and PSNH was in compliance with this provision.

16. COMMON SHARES

The following table sets forth the NU common shares and the shares of common stock of CL&P, NSTAR Electric, PSNH and WMECO that were authorized and issued and the respective per share par values:

	Per Share Par Value	Shares: Authorized as of December 31, 2014 and 2013	Issued as of December 31, 2014	Issued as of December 31, 2013
NU	$ 5	380,000,000	333,359,172	333,113,492
CL&P	$ 10	24,500,000	6,035,205	6,035,205
NSTAR Electric	$ 1	100,000,000	100	100
PSNH	$ 1	100,000,000	301	301
WMECO	$ 25	1,072,471	434,653	434,653

As of December 31, 2014 and 2013, there were 16,375,835 and 17,796,672 NU common shares held as treasury shares, respectively. As of December 31, 2014 and 2013, NU common shares outstanding were 316,983,337 and 315,273,559, respectively.

17. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

The CL&P and NSTAR Electric preferred stock is not subject to mandatory redemption and is presented as a noncontrolling interest of a subsidiary in NU's financial statements.

CL&P Preferred Stock: CL&P's charter authorizes it to issue up to 9 million shares of preferred stock ($50 par value per share). The issuance of additional preferred shares would be subject to PURA approval. Preferred stockholders have liquidation rights equal to the par value of the preferred stock, which they would receive in preference to any distributions to any junior stock. Were there to be a shortfall, all preferred stockholders would share ratably in available liquidation assets.

NSTAR Electric Preferred Stock: NSTAR Electric is authorized to issue 2,890,000 shares ($100 par value per share). NSTAR Electric has two outstanding series of cumulative preferred stock. Upon liquidation, holders of cumulative preferred stock are entitled to receive a liquidation preference before any distribution to holders of common stock. The liquidation preference for each outstanding series of cumulative preferred stock is equal to the par value, plus accrued and unpaid dividends. Were there to be a shortfall, holders of cumulative preferred stock would share ratably in available liquidation assets.

Details of preferred stock not subject to mandatory redemption are as follows (in millions except in redemption price and shares):

Series	Redemption Price Per Share	Shares Outstanding as of December 31, 2014 and 2013	As of December 31, 2014	2013
CL&P				
\$ 1.90 Series of 1947	\$ 52.50	163,912	\$ 8.2	\$ 8.2
\$ 2.00 Series of 1947	\$ 54.00	336,088	16.8	16.8
\$ 2.04 Series of 1949	\$ 52.00	100,000	5.0	5.0
\$ 2.20 Series of 1949	\$ 52.50	200,000	10.0	10.0
3.90 % Series of 1949	\$ 50.50	160,000	8.0	8.0
\$ 2.06 Series E of 1954	\$ 51.00	200,000	10.0	10.0
\$ 2.09 Series F of 1955	\$ 51.00	100,000	5.0	5.0
4.50 % Series of 1956	\$ 50.75	104,000	5.2	5.2
4.96 % Series of 1958	\$ 50.50	100,000	5.0	5.0
4.50 % Series of 1963	\$ 50.50	160,000	8.0	8.0
5.28 % Series of 1967	\$ 51.43	200,000	10.0	10.0
\$ 3.24 Series G of 1968	\$ 51.84	300,000	15.0	15.0
6.56 % Series of 1968	\$ 51.44	200,000	10.0	10.0
Total CL&P		2,324,000	\$ 116.2	\$ 116.2
NSTAR Electric				
4.25 % Series	\$ 103.625	180,000	\$ 18.0	\$ 18.0
4.78 % Series	\$ 102.80	250,000	25.0	25.0
Total NSTAR Electric		430,000	\$ 43.0	\$ 43.0
Fair Value Adjustment due to Merger with NSTAR			(3.6)	(3.6)
Total NU - Preferred Stock of Subsidiaries			\$ 155.6	\$ 155.6

18. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS

A summary of the changes in Common Shareholders' Equity and Noncontrolling Interests of NU is as follows:

(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Noncontrolling Interest - Preferred Stock of Subsidiaries
Balance as of January 1, 2012	\$ 4,012.7	\$ 3.0	\$ 4,015.7	\$ 116.2
Net Income	533.1	-	533.1	-
Purchase Price of NSTAR [1]	5,038.3	-	5,038.3	-
Other Equity Impacts of Merger with NSTAR [2]	3.4	(3.4)	-	39.4
Dividends on Common Shares	(375.5)	-	(375.5)	-
Dividends on Preferred Stock	(7.0)	-	(7.0)	(7.0)
Issuance of Common Shares	13.3	-	13.3	-
Contributions to NPT	-	0.3	0.3	-
Other Transactions, Net	21.1	-	21.1	-
Net Income Attributable to Noncontrolling Interests	(0.1)	0.1	-	7.0
Other Comprehensive Loss	(2.2)	-	(2.2)	-
Balance as of December 31, 2012	\$ 9,237.1	\$ -	\$ 9,237.1	\$ 155.6
Net Income	793.7	-	793.7	-
Dividends on Common Shares	(462.7)	-	(462.7)	-
Dividends on Preferred Stock	(7.7)	-	(7.7)	(7.7)
Issuance of Common Shares	11.1	-	11.1	-
Other Transactions, Net	13.2	-	13.2	-
Net Income Attributable to Noncontrolling Interests	-	-	-	7.7
Other Comprehensive Income	26.8	-	26.8	-
Balance as of December 31, 2013	\$ 9,611.5	\$ -	\$ 9,611.5	\$ 155.6
Net Income	827.1	-	827.1	-
Dividends on Common Shares	(496.5)	-	(496.5)	-
Dividends on Preferred Stock	(7.5)	-	(7.5)	(7.5)
Issuance of Common Shares	6.6	-	6.6	-
Other Transactions, Net	63.6	-	63.6	-
Net Income Attributable to Noncontrolling Interests	-	-	-	7.5
Other Comprehensive Loss	(28.0)	-	(28.0)	-
Balance as of December 31, 2014	\$ 9,976.8	\$ -	\$ 9,976.8	\$ 155.6

(1) On April 10, 2012, NU issued approximately 136 million common shares to the NSTAR shareholders in connection with the merger. See Note 21, "Merger of NU and NSTAR," for further information.

(2) The preferred stock of NSTAR Electric is not subject to mandatory redemption and has been presented as a noncontrolling interest in NSTAR Electric in NU's financial statements. In addition, upon completion of the merger, an NSTAR subsidiary that held 25 percent of NPT was merged into EETV, resulting in EETV owning 100 percent of NPT. Accordingly, the noncontrolling interest balance was eliminated and 100 percent ownership of NPT was reflected in Common Shareholders' Equity.

For the years ended December 31, 2014, 2013 and 2012, there was no change in ownership of the common equity of CL&P and NSTAR Electric.

19. EARNINGS PER SHARE

Basic EPS is computed based upon the weighted average number of common shares outstanding during each period. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect of certain share-based compensation awards as if they were converted into common shares. For the years ended December 31, 2014, 2013 and 2012, there were 3,643, 1,575 and 4,266, respectively, antidilutive share awards excluded from the computation.

The following table sets forth the components of basic and diluted EPS:

	For the Years Ended December 31,		
(Millions of Dollars, except share information)	2014	2013	2012
Net Income Attributable to Controlling Interest	$ 819.5	$ 786.0	$ 525.9
Weighted Average Common Shares Outstanding:			
Basic	316,136,748	315,311,387	277,209,819
Dilutive Effect	1,280,666	899,773	783,812
Diluted	317,417,414	316,211,160	277,993,631
Basic EPS	$ 2.59	$ 2.49	$ 1.90
Diluted EPS	$ 2.58	$ 2.49	$ 1.89

On April 10, 2012, NU issued approximately 136 million common shares as a result of the merger with NSTAR, which are reflected in the weighted average common shares outstanding.

RSUs and performance shares are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied. The dilutive effect of unvested RSUs and performance shares is calculated using the treasury stock method. Assumed proceeds of these units under the treasury stock method consist of the remaining compensation cost to be recognized and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the units (the difference between the market value of the average units outstanding for the period, using the average market price during the period, and the grant date market value).

The dilutive effect of stock options to purchase common shares is also calculated using the treasury stock method. Assumed proceeds for stock options consist of cash proceeds that would be received upon exercise, and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the stock options (the difference between the market value of the average stock options outstanding for the period, using the average market price during the period, and the exercise price).

20. SEGMENT INFORMATION

Presentation: NU is organized between the Electric Distribution, Electric Transmission and Natural Gas Distribution reportable segments and Other based on a combination of factors, including the characteristics of each segments' products and services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. These reportable segments represented substantially all of NU's total consolidated revenues for the years ended December 31, 2014, 2013 and 2012. Revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer. The Electric Distribution reportable segment includes the generation activities of PSNH and WMECO.

The remainder of NU's operations is presented as Other in the tables below and primarily consists of 1) the equity in earnings of NU parent from its subsidiaries and intercompany interest income, both of which are eliminated in consolidation, and interest expense related to the debt of NU parent, 2) the revenues and expenses of NU's service company, most of which are eliminated in consolidation, 3) the operations of CYAPC and YAEC, and 4) the results of other non-regulated subsidiaries, which are not part of its core business.

Cash flows used for investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension expense.

NU's reportable segments are determined based upon the level at which NU's chief operating decision maker assesses performance and makes decisions about the allocation of company resources. Each of NU's subsidiaries, including CL&P, NSTAR Electric, PSNH and WMECO, has one reportable segment. NU's operating segments and reporting units are consistent with its reportable business segments.

NSTAR amounts were included in NU beginning April 10, 2012.

NU's segment information is as follows:

	For the Year Ended December 31, 2014					
(Millions of Dollars)	**Electric Distribution**	**Natural Gas Distribution**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 5,663.4	$ 1,007.3	$ 1,018.2	$ 790.9	$ (737.9)	$ 7,741.9
Depreciation and Amortization	(384.6)	(68.1)	(150.5)	(42.1)	19.9	(625.4)
Other Operating Expenses	(4,366.2)	(786.7)	(302.1)	(748.0)	719.3	(5,483.7)
Operating Income	912.6	152.5	565.6	0.8	1.3	1,632.8
Interest Expense	(191.6)	(34.0)	(104.1)	(36.6)	4.2	(362.1)
Interest Income	5.1	-	0.9	3.6	(3.6)	6.0
Other Income, Net	10.7	0.2	10.3	916.0	(918.6)	18.6
Income Tax (Expense)/Benefit	(269.7)	(46.4)	(174.5)	22.3	-	(468.3)
Net Income	467.1	72.3	298.2	906.1	(916.7)	827.0
Net Income Attributable to Noncontrolling Interests	(4.7)	-	(2.8)	-	-	(7.5)
Net Income Attributable to Controlling Interest	$ 462.4	$ 72.3	$ 295.4	$ 906.1	$ (916.7)	$ 819.5
Total Assets (as of)	$ 17,563.4	$ 3,030.9	$ 7,625.6	$ 12,682.5	$ (11,124.4)	$ 29,778.0
Cash Flows Used for Investments in Plant	$ 645.2	$ 176.7	$ 731.6	$ 50.2	$ -	$ 1,603.7

	For the Year Ended December 31, 2013					
(Millions of Dollars)	**Electric Distribution**	**Natural Gas Distribution**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 5,362.3	$ 855.8	$ 978.7	$ 777.5	$ (673.1)	$ 7,301.2
Depreciation and Amortization	(604.8)	(66.7)	(136.2)	(62.2)	10.2	(859.7)
Other Operating Expenses	(3,927.7)	(659.4)	(281.8)	(715.0)	671.8	(4,912.1)
Operating Income	829.8	129.7	560.7	0.3	8.9	1,529.4
Interest Expense	(175.0)	(33.1)	(100.3)	(35.5)	5.2	(338.7)
Interest Income	4.1	-	0.7	5.4	(5.6)	4.6
Other Income, Net	12.9	0.8	10.9	858.9	(858.2)	25.3
Income Tax (Expense)/Benefit	(240.0)	(36.5)	(182.1)	31.9	(0.2)	(426.9)
Net Income	431.8	60.9	289.9	861.0	(849.9)	793.7
Net Income Attributable to Noncontrolling Interests	(4.8)	-	(2.9)	-	-	(7.7)
Net Income Attributable to Controlling Interest	$ 427.0	$ 60.9	$ 287.0	$ 861.0	$ (849.9)	$ 786.0
Total Assets (as of)	$ 17,260.0	$ 2,759.7	$ 6,745.8	$ 11,842.4	$ (10,812.4)	$ 27,795.5
Cash Flows Used for Investments in Plant	$ 639.0	$ 168.1	$ 618.5	$ 31.2	$ -	$ 1,456.8

	For the Year Ended December 31, 2012					
(Millions of Dollars)	**Electric Distribution**	**Natural Gas Distribution**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 4,716.5	$ 572.9	$ 861.5	$ 803.8	$ (680.9)	$ 6,273.8
Depreciation and Amortization	(530.3)	(49.1)	(109.2)	(56.4)	4.2	(740.8)
Other Operating Expenses	(3,585.4)	(445.2)	(251.6)	(817.0)	684.4	(4,414.8)
Operating Income/(Loss)	600.8	78.6	500.7	(69.6)	7.7	1,118.2
Interest Expense	(165.6)	(31.3)	(96.7)	(43.6)	7.3	(329.9)
Interest Income	2.8	-	0.4	7.1	(7.1)	3.2
Other Income, Net	8.9	0.4	7.3	795.0	(795.1)	16.5
Income Tax (Expense)/Benefit	(150.2)	(16.9)	(159.2)	55.5	(4.1)	(274.9)
Net Income	296.7	30.8	252.5	744.4	(791.3)	533.1
Net Income Attributable to Noncontrolling Interests	(4.4)	-	(2.8)	-	-	(7.2)
Net Income Attributable to Controlling Interest	$ 292.3	$ 30.8	$ 249.7	$ 744.4	$ (791.3)	$ 525.9
Cash Flows Used for Investments in Plant	$ 611.7	$ 148.7	$ 663.6	$ 48.3	$ -	$ 1,472.3

21. MERGER OF NU AND NSTAR

On April 10, 2012, NU acquired 100 percent of the outstanding common shares of NSTAR. Pursuant to the terms and conditions of the Agreement and Plan of Merger, as amended, (the "Merger Agreement,") NSTAR and its subsidiaries became wholly-owned subsidiaries of NU.

NSTAR was a holding company engaged through its subsidiaries in the energy delivery business serving electric and natural gas distribution customers in Massachusetts. As part of the merger, NSTAR shareholders received 1.312 NU common shares for each NSTAR common share owned (the "exchange ratio") as of the acquisition date. NU issued approximately 136 million common shares to the NSTAR shareholders as a result of the merger.

Purchase Price: Pursuant to the merger, all of the NSTAR common shares were exchanged at the fixed exchange ratio of 1.312 NU common shares for each NSTAR common share. The total consideration transferred in the merger was based on the closing price of NU common shares on April 9, 2012, the day prior to the date the merger was completed, and was calculated as follows:

NSTAR common shares outstanding as of April 9, 2012 (in thousands)*		103,696
Exchange ratio		1.312
NU common shares issued for NSTAR common shares outstanding (in thousands)		136,049
Closing price of NU common shares on April 9, 2012	$	36.79
Value of common shares issued (in millions)	$	5,005
Fair value of NU replacement stock-based compensation awards related to pre-merger service (in millions)		33
Total purchase price (in millions)	$	5,038

* Included 109 thousand shares related to NSTAR stock-based compensation awards that vested immediately prior to the merger.

Certain of NSTAR's stock-based compensation awards, including deferred shares, performance shares and all outstanding stock options, were replaced with NU awards using the exchange ratio upon consummation of the merger. In accordance with accounting guidance for business combinations, the portion of the fair value of these awards attributable to service provided prior to the merger was included in the purchase price as it represented consideration transferred in the merger. See Note 9C, "Employee Benefits – Share-Based Payments," for further information.

Purchase Price Allocation: The allocation of the total purchase price to the estimated fair values of the assets acquired and liabilities assumed was determined based on the accounting guidance for fair value measurements. The allocation of the total purchase price included adjustments to record the fair value of NSTAR's unregulated telecommunications business, regulatory assets not earning a return, lease agreements, long-term debt and the preferred stock of NSTAR Electric. The fair values of NSTAR's assets and liabilities were determined based on significant estimates and assumptions, including Level 3 inputs, that were judgmental in nature. These estimates and assumptions included the timing and amounts of projected future cash flows and discount rates reflecting risk inherent in future cash flows.

In accordance with accounting guidance for business combinations, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill.

The goodwill from the merger with NSTAR totaled $3.2 billion and was allocated to NU's reporting units based on their estimated fair values. See Note 22, "Goodwill," for the allocation of goodwill to each reporting unit.

Pro Forma Financial Information: The following unaudited pro forma financial information reflects the pro forma combined results of operations of NU and NSTAR and reflects the amortization of purchase price adjustments assuming the merger had taken place on January 1, 2011. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of NU.

(Pro forma amounts in millions, except per share amounts)	**For the Year Ended December 31, 2012**	
Operating Revenues	$	7,004
Net Income Attributable to Controlling Interest		630
Basic EPS		2.00
Diluted EPS		1.99

Pro forma net income does not include potential cost savings associated with the merger. Pro forma net income also excludes certain non-recurring merger costs and costs related to the Connecticut and Massachusetts merger settlement agreements described below, with the following aggregate after-tax impacts:

(Millions of Dollars)	**For the Year Ended December 31, 2012**	
Transaction and Other Costs	$	32
Settlement Agreement Impacts		60
Total After-Tax Non-Recurring Costs Excluded from Pro Forma Net Income Attributable to Controlling Interest	$	92

Regulatory Approvals: On February 15, 2012, NU and NSTAR reached comprehensive merger settlement agreements with the Massachusetts Attorney General and the DOER. The Attorney General settlement agreement covered a variety of rate-making and rate design issues, including a base distribution rate freeze through 2015 for NSTAR Electric, NSTAR Gas and WMECO and $15 million, $3 million and $3 million in the form of rate credits to their respective customers. On April 4, 2012, the DPU approved the settlement agreements and the merger of NU and NSTAR.

On March 13, 2012, NU and NSTAR reached a comprehensive merger settlement agreement with both the Connecticut Attorney General and the Connecticut Office of Consumer Counsel. The settlement agreement covered a variety of matters, including a $25 million rate credit to CL&P customers, a CL&P base distribution rate freeze until December 1, 2014, and the establishment of a $15 million fund for energy efficiency and other initiatives to be disbursed at the direction of the DEEP. In the agreement, CL&P agreed to forego rate recovery of $40 million of the deferred storm restoration costs associated with restoration activities following Tropical Storm Irene and the October 2011 snowstorm. On April 2, 2012, the PURA approved the settlement agreement and the merger of NU and NSTAR.

The pre-tax financial impacts of the Connecticut and Massachusetts merger settlement agreements that were recognized in 2012 by NU, CL&P, NSTAR Electric, and WMECO are summarized as follows:

(Millions of Dollars)	NU	CL&P	NSTAR Electric	WMECO
Customer Rate Credits	$ 46	$ 25	$ 15	$ 3
Storm Costs Deferral Reduction	40	40	-	-
Establishment of Energy Efficiency Fund	15	-	-	-
Total Pre-Tax Settlement Agreement Impacts	$ 101	$ 65	$ 15	$ 3

22. GOODWILL

In accordance with the accounting standards, goodwill is not subject to amortization. However, goodwill is subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are charged to Operating Expenses. These accounting standards require that goodwill be reviewed at least annually for impairment and whenever facts or circumstances indicate that there may be an impairment. NU uses October 1st as the annual goodwill impairment testing date.

On April 10, 2012, upon consummation of the merger with NSTAR, NU recorded approximately $3.2 billion of goodwill. With the completion of the merger, NU reviewed its management structure and determined that the reporting units for the purpose of testing goodwill for impairment are Electric Distribution, Electric Transmission and Natural Gas Distribution. NU's reporting units are consistent with the operating segments underlying the reportable segments identified in Note 20, "Segment Information," to the financial statements. Accordingly, the goodwill resulting from the merger was allocated to the Electric Distribution, Electric Transmission and Natural Gas Distribution reporting units based on the estimated fair values of the reporting units as of the merger date.

Prior to the merger with NSTAR, the only reporting unit that maintained goodwill was the Natural Gas Distribution reportable segment related to the acquisition of the parent of Yankee Gas in 2000. This goodwill was recorded at Yankee Gas. The goodwill balance at Yankee Gas as of December 31, 2014 and 2013 was $0.3 billion.

NU completed its annual goodwill impairment test for each of its reporting units as of October 1, 2014 and determined that no impairment exists. There were no events subsequent to October 1, 2014 that indicated impairment of goodwill.

There were no changes to the goodwill balance or the allocation of goodwill as of December 31, 2014 or 2013. The allocation of goodwill to NU's reporting units as of both December 31, 2014 and 2013 was as follows:

(Billions of Dollars)	Electric Distribution	Electric Transmission	Natural Gas Distribution	Total
Goodwill Allocation	$ 2.5	$ 0.6	$ 0.4	$ 3.5

23. VARIABLE INTEREST ENTITIES

The Company's variable interests outside of the consolidated group are not material and consist of contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. NU, CL&P and NSTAR Electric hold variable interests in variable interest entities (VIEs) through agreements with certain entities that own single renewable energy or peaking generation power plants and with other independent power producers. NU, CL&P and NSTAR Electric do not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, NU, CL&P and NSTAR Electric do not consolidate any power plant VIEs.

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

NU Consolidated Statements of Quarterly Financial Data	Quarter Ended			
(Millions of Dollars, except per share information)	March 31,	June 30,	September 30,	December 31,
2014				
Operating Revenues	$ 2,290.6	$ 1,677.6	$ 1,892.5	$ 1,881.2
Operating Income	467.7	294.0	440.9	430.2
Net Income	237.8	129.2	236.5	223.6
Net Income Attributable to Controlling Interest	236.0	127.4	234.6	221.5
Basic EPS (a)	$ 0.75	$ 0.40	$ 0.74	$ 0.69
Diluted EPS (a)	$ 0.74	$ 0.40	$ 0.74	$ 0.69
2013				
Operating Revenues	$ 1,995.0	$ 1,635.9	$ 1,892.6	$ 1,777.7
Operating Income	418.9	350.6	399.3	360.6
Net Income	230.0	173.1	211.4	179.2
Net Income Attributable to Controlling Interest	228.1	171.0	209.5	177.4
Basic and Diluted EPS (a)	$ 0.72	$ 0.54	$ 0.66	$ 0.56

(a) The summation of quarterly EPS data may not equal annual data due to rounding.

Statements of Quarterly Financial Data *(Millions of Dollars)*	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
CL&P				
2014				
Operating Revenues	$ 734.6	$ 587.3	$ 695.6	$ 675.1
Operating Income	158.0	92.1	146.2	159.0
Net Income	79.3	37.4	83.9	87.2
2013				
Operating Revenues	$ 624.1	$ 569.3	$ 648.4	$ 600.5
Operating Income	149.7	136.8	133.9	119.2
Net Income	85.0	67.9	66.3	60.2
NSTAR Electric				
2014				
Operating Revenues	$ 666.2	$ 561.5	$ 727.9	$ 581.1
Operating Income	118.4	121.5	206.6	132.0
Net Income	58.1	60.1	115.6	69.3
2013				
Operating Revenues	$ 592.3	$ 570.4	$ 753.9	$ 576.9
Operating Income	94.5	112.5	192.0	109.2
Net Income	48.1	58.0	107.0	55.4
PSNH				
2014				
Operating Revenues	$ 299.8	$ 211.6	$ 223.7	$ 224.4
Operating Income	64.0	49.0	56.4	60.0
Net Income	32.6	24.1	28.2	29.0
2013				
Operating Revenues	$ 273.8	$ 216.1	$ 218.6	$ 226.9
Operating Income	58.1	54.3	56.6	56.2
Net Income	29.0	27.2	28.4	26.8
WMECO				
2014				
Operating Revenues	$ 137.4	$ 108.3	$ 118.1	$ 129.6
Operating Income	34.7	17.7	31.2	34.0
Net Income	18.1	7.0	14.7	18.0
2013				
Operating Revenues	$ 125.0	$ 115.0	$ 121.8	$ 110.9
Operating Income	35.6	32.4	28.9	22.4
Net Income	18.6	16.4	15.0	10.4

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

No events that would be described in response to this item have occurred with respect to NU, CL&P, NSTAR Electric, PSNH or WMECO.

Item 9A. Controls and Procedures

Management, on behalf of NU, CL&P, NSTAR Electric, PSNH and WMECO, is responsible for the preparation, integrity, and fair presentation of the accompanying Consolidated Financial Statements and other sections of this combined Annual Report on Form 10-K. NU's internal controls over financial reporting were audited by Deloitte & Touche LLP.

Management, on behalf of NU, CL&P, NSTAR Electric, PSNH and WMECO, is responsible for establishing and maintaining adequate internal controls over financial reporting. The internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment. Under the supervision and with the participation of the principal executive officer and principal financial officer, an evaluation of the effectiveness of internal controls over financial reporting was conducted based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting at NU, CL&P, NSTAR Electric, PSNH and WMECO were effective as of December 31, 2014.

Management, on behalf of NU, CL&P, NSTAR Electric, PSNH and WMECO, evaluated the design and operation of the disclosure controls and procedures as of December 31, 2014 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Securities Exchange Act of 1934 and the rules and regulations of the SEC. This evaluation was made under management's supervision and with management's participation, including the principal executive officer and principal financial officer as of the end of the period covered by this Annual Report on Form 10-K. There are inherent limitations of disclosure controls and procedures, including the possibility of human error and the circumventing or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. The principal executive officer and principal financial officer have concluded, based on their review, that the disclosure controls and procedures of NU, CL&P, NSTAR Electric, PSNH and WMECO are effective to ensure that information required to be disclosed by us in reports filed under the Securities Exchange Act of 1934 (i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and regulations and (ii) is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

During the third quarter of 2014, we implemented a new general ledger system resulting in a material change in internal controls over financial reporting. This new system, which went live effective August 1, 2014, standardized the financial systems for the merged companies and allows for a common set of accounting processes, practices and data structures across all operating companies. Pre-implementation testing and post-implementation reviews were conducted by management to ensure that internal controls surrounding the system implementation process, the applications, and the closing process were properly designed to prevent material financial statement errors. Such procedures included the review of required documents, user acceptance testing, change management procedures, access controls, data migration strategies and reconciliations, application interface testing and other standard application controls.

There have been no other changes in internal controls over financial reporting for NU, CL&P, NSTAR Electric, PSNH and WMECO during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Item 9B. Other Information

No information is required to be disclosed under this item as of December 31, 2014, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2014.

Item 10. Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 18, 2015, except where otherwise indicated.

Certain information required by this Item 10 is omitted for NSTAR Electric, PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly Owned Subsidiaries.

NU

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information to be contained in the sections captioned "Election of Trustees," "Governance of Northeast Utilities" and the related subsections, "Selection of Trustees," and "Section 16(a) Beneficial Ownership Reporting Compliance" of NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 13, 2015.

NU and CL&P

Each member of CL&P's Board of Directors is an employee of CL&P, NU or an affiliate. Directors are elected annually to serve for one year until their successors are elected and qualified.

Set forth below is certain information as of February 18, 2015 concerning CL&P's Directors and NU's and CL&P's executive officers:

Name	Age	Title
Thomas J. May	67	Chairman of the Board, President and Chief Executive Officer of NU and NUSCO; Chairman and a Director of the Regulated companies, including CL&P
James J. Judge	59	Executive Vice President and Chief Financial Officer of NU and Executive Vice President and Chief Financial Officer and a Director of NUSCO and the Regulated companies, including CL&P
David R. McHale [1]	54	Executive Vice President and Chief Administrative Officer of NU and NUSCO
Leon J. Olivier	66	Executive Vice President-Enterprise Energy Strategy and Business Development of NU and NUSCO
Werner J. Schweiger	55	Executive Vice President and Chief Operating Officer of NU and NUSCO; Chief Executive Officer and a Director of the Regulated companies, including CL&P
Gregory B. Butler	57	Senior Vice President and General Counsel of NU and NUSCO; Senior Vice President and General Counsel and a Director of the Regulated companies, including CL&P
Christine M. Carmody [2]	52	Senior Vice President-Human Resources of NUSCO
Joseph R. Nolan, Jr. [2]	51	Senior Vice President-Corporate Relations of NUSCO
William P. Herdegen III [3]	60	President and Chief Operating Officer of CL&P
Jay S. Buth	45	Vice President, Controller and Chief Accounting Officer of NU, NUSCO and the Regulated companies, including CL&P

1 Deemed an executive officer of CL&P pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.
2 Deemed an executive officer of NU and CL&P pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.
3 Mr. Herdegen is the President and Chief Operating Officer of CL&P and is therefore an executive officer solely of CL&P.

Thomas J. May. Mr. May has served as Chairman of the Board of NU since October 10, 2013, and as President and Chief Executive Officer and as a Trustee of NU; as Chairman and a Director of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas; and as Chairman, President and Chief Executive Officer and a Director of NUSCO since April 10, 2012. Mr. May has served as a Director of NSTAR Electric and NSTAR Gas since September 27, 1999. Mr. May previously served as Chairman, President and Chief Executive Officer and a Trustee of NSTAR, and as Chairman, President and Chief Executive Officer of NSTAR Electric and NSTAR Gas until April 10, 2012. He served as Chairman, Chief Executive Officer and a Trustee since NSTAR was formed in 1999, and was elected President in 2002. Mr. May has served as Chairman of the Board of Eversource Energy Foundation, Inc. since October 15, 2013, and as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. He previously served as President of Eversource Energy Foundation, Inc. from October 15, 2013 to September 29, 2014. He has served as a Trustee of the NSTAR Foundation since August 18, 1987.

James J. Judge. Mr. Judge has served as Executive Vice President and Chief Financial Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO and as a Director of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012 and of NSTAR Electric and NSTAR Gas since September 27, 1999. Previously, Mr. Judge served as Senior Vice President and Chief Financial Officer of NSTAR, NSTAR Electric and NSTAR Gas from 1999 until April 2012. Mr. Judge has served as Treasurer and as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. He has served as a Trustee of the NSTAR Foundation since December 12, 1995.

David R. McHale. Mr. McHale has served as Executive Vice President and Chief Administrative Officer of NU and NUSCO since April 10, 2012 and as a Director of NUSCO since January 1, 2005. Mr. McHale previously served as Executive Vice President and Chief Administrative Officer of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and as a Director of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014, of PSNH, WMECO and Yankee Gas from January 1, 2005 to September 29, 2014, and of CL&P from January 15, 2007 to September 29, 2014. Previously, Mr. McHale served as Executive Vice President and

Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2009 to April 2012, and as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from January 2005 to December 2008. He has served as a Director of Eversource Energy Foundation, Inc. since January 1, 2005. Mr. McHale has served as a Trustee of the NSTAR Foundation since April 10, 2012.

Leon J. Olivier. Mr. Olivier has served as Executive Vice President-Enterprise Energy Strategy and Business Development of NU since September 2, 2014 and as a Director of NUSCO since January 17, 2005. Mr. Olivier previously served as Executive Vice President and Chief Operating Officer of NU and NUSCO from May 13, 2008 until September 2, 2014, and as Chief Executive Officer of NSTAR Electric and NSTAR Gas from April 10, 2012 until August 11, 2014, of CL&P, PSNH, WMECO and Yankee Gas from January 15, 2007 to September 29, 2014, and of CL&P from September 10, 2001 to September 29, 2014, and as a Director of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014, of PSNH, WMECO and Yankee Gas from January 17, 2005 to September 29, 2014, and of CL&P from September 10, 2001 to September 29, 2014. Previously, Mr. Olivier served as Executive Vice President-Operations of NU from February 13, 2007 to May 12, 2008. He has served as a Director of Eversource Energy Foundation, Inc. since April 1, 2006. Mr. Olivier has served as a Trustee of the NSTAR Foundation since April 10, 2012.

Werner J. Schweiger. Mr. Schweiger has served as Executive Vice President and Chief Operating Officer of NU since September 2, 2014 and of NUSCO since August 11, 2014, and as Chief Executive Officer of CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO and Yankee Gas since August 11, 2014, and as a Director of NUSCO, NSTAR Gas and Yankee Gas since September 29, 2014 and of CL&P, PSNH, NSTAR Electric and WMECO since May 28, 2013. He previously served as President-Electric Distribution of NUSCO from January 16, 2013 until August 11, 2014 and as President of NSTAR Electric from April 10, 2012 until January 16, 2013 and as a Director of NSTAR Electric from November 27, 2012 to January 16, 2013. From February 27, 2002 until April 10, 2012, Mr. Schweiger was Senior Vice President-Operations of NSTAR Electric and NSTAR Gas. Mr. Schweiger has served as a Director of Eversource Energy Foundation, Inc. since September 29, 2014. He has served as a Trustee of the NSTAR Foundation since April 25, 2002.

Gregory B. Butler. Mr. Butler has served as Senior Vice President and General Counsel of NU since May 1, 2014, of NSTAR Electric, and NSTAR Gas since April 10, 2012, and of CL&P, PSNH, WMECO, Yankee Gas and NUSCO since March 9, 2006. Mr. Butler has served as a Director of NSTAR Electric and NSTAR Gas since April 10, 2012, of NUSCO since November 27, 2012, and of CL&P, PSNH, WMECO and Yankee Gas since April 22, 2009. Mr. Butler previously served as Senior Vice President, General Counsel and Secretary of NU from April 10, 2012 until May 1, 2014, and as Senior Vice President and General Counsel of NU from December 1, 2005 to April 10, 2012. He has served as a Director of Eversource Energy Foundation, Inc. since December 1, 2002.

Christine M. Carmody. Ms. Carmody has served as Senior Vice President-Human Resources of NUSCO since April 10, 2012 and as a Director of NUSCO since November 27, 2012. Ms. Carmody previously served as Senior Vice President-Human Resources of CL&P, PSNH, WMECO and Yankee Gas from November 27, 2012 to September 29, 2014, and of NSTAR Electric and NSTAR Gas from August 1, 2008 to September 29, 2014, and as a Director of CL&P, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014. Previously, Ms. Carmody served as Vice President-Organizational Effectiveness of NSTAR, NSTAR Electric and NSTAR Gas from June 2006 to August 2008. Ms. Carmody has served as a Director of Eversource Energy Foundation, Inc. since April 10, 2012. She has served as a Trustee of the NSTAR Foundation since August 1, 2008.

Joseph R. Nolan, Jr. Mr. Nolan has served as Senior Vice President-Corporate Relations of NUSCO since April 10, 2012 and as a Director of NUSCO since November 27, 2012. Mr. Nolan previously served as Senior Vice President-Corporate Relations of NSTAR Electric and NSTAR Gas from April 10, 2012 to September 29, 2014, and of CL&P, PSNH, WMECO and Yankee Gas from November 27, 2012 to September 29, 2014, as a Director of CL&P, PSNH, WMECO and Yankee Gas from April 10, 2012 to September 29, 2014 and of NSTAR Electric and NSTAR Gas from November 27, 2012 to September 29, 2014. Previously, Mr. Nolan served as Senior Vice President-Customer & Corporate Relations of NSTAR, NSTAR Electric and NSTAR Gas from 2006 until April 10, 2012. Mr. Nolan has served as a Director of Eversource Energy Foundation, Inc. since April 10, 2012, and has served as Executive Director of Eversource Energy Foundation, Inc. since October 15, 2013. He has served as a Trustee of the NSTAR Foundation since October 1, 2000.

William P. Herdegen III. Mr. Herdegen has served as President and Chief Operating Officer of CL&P since September 11, 2012 and as a Director of CL&P from September 11, 2012 to September 29, 2014. Previously, Mr. Herdegen served as Vice President of Transmission and Distribution Engineering and Operations for Kansas City Power & Light Company from 2008 until his retirement on September 7, 2012; as Vice President, Distribution and Customer Operations from 2005 to 2008; and as Vice President, Distribution Operations from 2001 to 2005. Mr. Herdegen began his utility career at Commonwealth Edison, where he held various positions, including Vice President, Engineering, Construction and Maintenance, corporate project manager, operations manager, business unit supply manager, district manager, and field engineer.

Jay S. Buth. Mr. Buth has served as Vice President, Controller and Chief Accounting Officer of NU, CL&P, NSTAR Electric, NSTAR Gas, PSNH, WMECO, Yankee Gas and NUSCO since April 10, 2012. Previously, Mr. Buth served as Vice President-Accounting and Controller of NU, CL&P, PSNH, WMECO, Yankee Gas and NUSCO from June 2009 until April 10, 2012. From June 2006 through January 2009, Mr. Buth served as the Vice President and Controller for New Jersey Resources Corporation, an energy services holding company that provides natural gas and wholesale energy services, including transportation, distribution and asset management.

There are no family relationships between any director or executive officer and any other trustee, director or executive officer of NU or CL&P and none of the above executive officers or directors serves as an executive officer or director pursuant to any agreement or understanding with any other person. Our executive officers hold the offices set forth opposite their names until the next annual meeting of the Board of Trustees, in the case of NU, and the Board of Directors, in the case of CL&P, and until their successors have been elected and qualified.

CL&P obtains audit services from the independent registered public accounting firm engaged by the Audit Committee of NU's Board of Trustees. CL&P does not have its own audit committee or, accordingly, an audit committee financial expert. CL&P relies on NU's audit committee and the audit committee financial expert.

CODE OF ETHICS AND STANDARDS OF BUSINESS CONDUCT

Each of NU, CL&P, NSTAR Electric, PSNH and WMECO has adopted a Code of Ethics for Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) and the Code of Business Conduct, which are applicable to all Trustees, directors, officers, employees, contractors and agents of NU, CL&P, NSTAR Electric, PSNH and WMECO. The Code of Ethics and the Code of Business Conduct have both been posted on the NU web site and are available at www.eversource.com/investors/corporate_gov/default.asp on the Internet. Any amendments to or waivers from the Code of Ethics and Code of Business Conduct for executive officers, directors or Trustees will be posted on the website. Any such amendment or waiver would require the prior consent of the Board of Trustees or an applicable committee thereof.

Printed copies of the Code of Ethics and the Code of Business Conduct are also available to any shareholder without charge upon written request mailed to:

Richard J. Morrison
Secretary
Eversource Energy
P.O. Box 270
Hartford, CT 06141

Item 11. Executive Compensation

NU

The information required by this Item 11 for NU is incorporated herein by reference to certain information contained in NU's definitive proxy statement for solicitation of proxies, which is expected to be filed with the SEC on or about March 13, 2015, under the sections captioned "Compensation Discussion and Analysis," plus related subsections, and "Compensation Committee Report," plus related subsections following such Report.

NSTAR ELECTRIC, PSNH and WMECO

Certain information required by this Item 11 has been omitted for NSTAR Electric, PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly Owned Subsidiaries.

CL&P

The information in this Item 11 relates solely to CL&P.

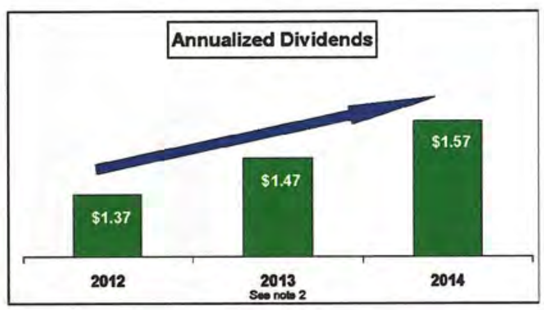
COMPENSATION DISCUSSION AND ANALYSIS

CL&P is a wholly-owned subsidiary of NU. Its board of directors consists entirely of executive officers of NU. CL&P does not have a compensation committee, and the Compensation Committee of NU's Board of Trustees determines compensation for the executive officers of CL&P, including their salaries, annual incentive awards and long-term incentive awards. All of CL&P's "Named Executive Officers," as defined below, also serve as officers of NU and one or more other subsidiaries of NU. Compensation set by the Compensation Committee of NU (the "Committee") and set forth herein is for services rendered to NU and its subsidiaries by such officers in all capacities.

The purpose of this Compensation Discussion and Analysis is to provide information about NU's compensation objectives, plans, policies and actions for the Named Executive Officers. The discussion describes the specific components of the compensation program, how NU measures performance, and how compensation awards and decisions were made by the Compensation Committee for the Named Executive Officers, as presented in the tables and narratives that follow. While this discussion focuses primarily on 2014 information, it also addresses decisions that were made in other periods to the extent that these decisions are relevant to the full understanding of NU's compensation program and the specific awards that were made in 2014 and early 2015.

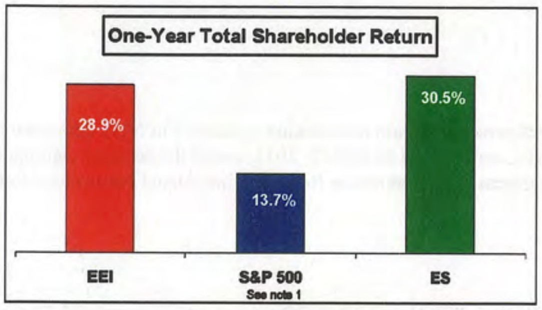
Business Highlights

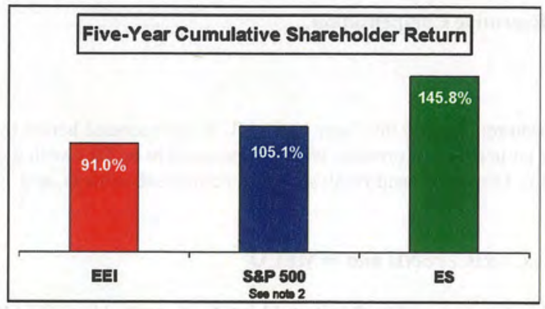
Since the merger with NSTAR in 2012, NU has continued to meet its commitment of achieving above-average earnings and dividend growth.



Note 1: 2012-2014 recurring earnings per share have grown 7.9%, consistent with NU's guidance and well above the industry average. Recurring earnings per share presented above for all years exclude merger-related costs. A reconciliation between reported earnings per share and the recurring earnings per share presented above appears under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations - Overview" in this Annual Report on Form 10-K.

Note 2: The NU Board of Trustees increased the annual dividend rate by 6.8 percent for 2014 to $1.57 per share, exceeding the Edison Electric Institute (EEI) Index dividend growth rate of 3.7%. 2012-2014 dividends have grown 7.0%, in line with NU's earnings per share growth and well ahead of the industry average.



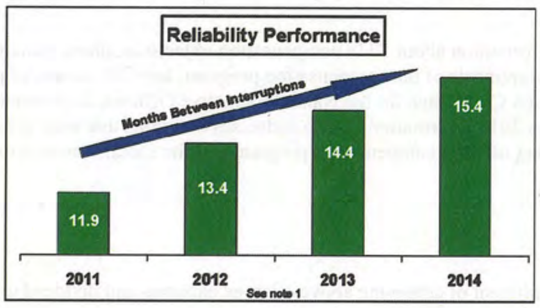


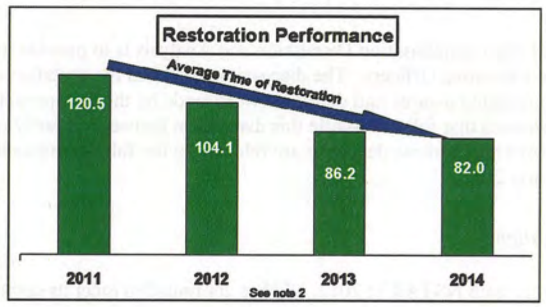
NU's Total Shareholder Return for the one-year and five-year periods has outperformed both the EEI Index and the S&P 500. NU's market capitalization at the end of 2014 grew to $17 billion, increasing shareholder value by over $8 billion in the 33-month period following the 2012 merger with NSTAR. NU commenced trading under the symbol "ES" on February 19, 2015.

Note 1: An investment of $1,000 in NU common shares at the beginning of the one-year period commencing January 1, 2014 was worth $1,305 on December 31, 2014.

Note 2: An investment of $1,000 in NU common shares at the beginning of the five-year period commencing January 1, 2010 was worth $2,458 on December 31, 2014.

NU's operating performance continues to improve each year. This is the result of the ongoing implementation of best practices, focused spending on reliability improvements to reduce the number and length of outages, and performing work safely each and every day.





Note 1: Reliability as measured by months between interruptions has improved significantly; on average, NU's customers experienced an outage every 15.4 months during 2014 vs. 11.9 months in 2011.

Note 2: The average time to restore power has decreased significantly, from 120.5 minutes in 2011 to 82.0 minutes in 2014.

Note 3: Safety performance measured by the days away or restricted time per 100 workers has improved significantly, to 1.44 in 2014 from 2.58 in 2011.

Summary of 2014 Performance

In 2014, NU achieved excellent financial and operational performance results. NU met or exceeded each of the challenging financial and operational goals established by the Committee at the beginning of 2014 and had the best system reliability results in NU's history. The following is a summary of some of NU's most important accomplishments in 2014:

Financial Accomplishments

- NU's 2014 recurring earnings were $2.65 per share, excluding merger related costs, a 4.7 percent increase over 2013 results.
- NU continued to achieve operating and maintenance expense reductions through successful integration activities, exceeding the goal of a greater than 3 percent reduction in operating expenses from 2013. Operating costs were 6.8 percent, or $101 million, lower than 2013.
- NU increased its dividend to $1.57 per share, a 6.8 percent increase over 2013, continuing to significantly outperform the industry average.
- NU delivered 30.5 percent total shareholder return in 2014, the sixth consecutive year of double digit total shareholder return, creating $8 billion in NU shareholder value in the 33-month period following NU's 2012 merger with NSTAR.

Total Shareholder Return

	2014	3-Year	5-Year	10-Year
ES	30.5%	64.3%	145.8%	297.7%
EEI Index	28.9%	48.7%	91.0%	156.0%
S&P 500	13.7%	74.6%	105.1%	109.4%

Operational Accomplishments

- NU's overall electric system performance in 2014 was the best on record and represents top quartile industry performance.
- NU's Massachusetts subsidiaries, NSTAR Electric Company, NSTAR Gas Company and Western Massachusetts Electric Company, paid no penalties for Service Quality Index performance in 2014 under regulations in Massachusetts, which is the only state NU serves that has specific performance targets.
- NU continued the focus on streamlining and fully integrating business processes across the company, including standardizing system design, equipment and operating and maintenance practices and implementing a new financial accounting and budgeting system in a well controlled and timely manner.
- NU exceeded established goals in calls answered on-time, safety performance, and response to gas service calls.

Achievement of the 2014 performance goals and additional accomplishments and the Committee's assessment of company and executive performance are more fully described in the section titled "2014 Annual Incentive Program." Specific decisions regarding executive compensation based upon the Committee's assessment of company and executive performance and market data are described in this Compensation Discussion and Analysis ("CD&A") below.

Pay for Performance

The Committee follows a philosophy of linking the Named Executive Officers' compensation to performance that will ultimately benefit customers and shareholders. The intent of NU's compensation program is to attract and retain the best executive talent, motivate the executives to meet or exceed specific stretch financial and operational goals set each year, and compensate the executives in a manner that aligns compensation directly with performance. NU strives to provide executives with base salary, performance-based annual incentive compensation and long-term incentive compensation opportunities that are competitive with market practices and that reward excellent performance.

Executive Compensation Governance

- The Committee annually assesses the independence of its compensation consultant, Pay Governance LLC (Pay Governance), which is retained directly by the Committee, performs no other consulting or other services for the company, and has no relationship with the company that could result in a conflict of interest. The Committee has concluded that Pay Governance is independent and that no conflict of interest exists between Pay Governance and the company.
- NU's executive and Trustee share ownership and holding guidelines noted in this CD&A emphasize the importance of share ownership. In addition to the share ownership guidelines requirement, NU requires its executives to hold the net shares awarded under the company's stock compensation program until the share ownership guidelines requirement has been met. In addition, 100% of Trustee stock compensation is deferred and not distributed until the Trustee's retirement from the Board.

- The Committee has a policy that would require NU's employees to reimburse the company for incentive compensation received if earnings were subsequently required to be restated as a result of noncompliance with accounting rules caused by fraud or misconduct.
- NU has discontinued the use of "gross-ups" in all new or materially amended executive compensation agreements.
- The Committee has a policy prohibiting all Trustees and employees from purchasing financial instruments or otherwise entering into any transactions that are designed to have the effect of hedging or offsetting any decrease in the market value of NU common shares. This policy also prohibits all pledging, derivative transactions or short sales involving NU common shares or the holding of any NU common shares in a margin account.
- Employment agreements provide for "double trigger" change of control acceleration of awards assumed by the surviving company.

NAMED EXECUTIVE OFFICERS

The executive officers of CL&P listed in the Summary Compensation Table in this Item 11 whose compensation is discussed in this CD&A are CL&P's principal executive officers during 2014 (Mr. Olivier and Mr. Schweiger), principal financial officer (Mr. Judge) and the three most highly compensated executive officers other than the principal executive officers and principal financial officer serving on December 31, 2014 (Messrs. May, McHale, and Butler) (collectively, referred to as the "Named Executive Officers" or "NEOs"). Each NEO of CL&P also serves as an executive officer of NU and one or more other subsidiaries of NU. Compensation for the NEOs discussed in this CD&A was paid for all services provided by such individuals in all capacities to NU and its subsidiaries. For 2014, CL&P's NEOs are:

- Thomas J. May, Chairman of the Board, President and Chief Executive Officer of NU; Chairman of the Board of CL&P
- James J. Judge, Executive Vice President and Chief Financial Officer of NU and CL&P
- Leon J. Olivier, Executive Vice President – Enterprise Energy Strategy and Business Development of NU
- David R. McHale, Executive Vice President and Chief Administrative Officer of NU and CL&P
- Werner J. Schweiger, Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of CL&P
- Gregory B. Butler, Senior Vice President and General Counsel of NU and CL&P

OVERVIEW OF COMPENSATION PROGRAM

The Role of the Compensation Committee. The NU Board of Trustees has delegated to the Committee overall responsibility for establishing the compensation program for those senior executive officers referred to in this Compensation Discussion and Analysis as "executives" and who under the SEC's regulations are deemed to be "officers." In this role, the Committee sets compensation policy and compensation levels, reviews and approves performance goals and evaluates executive performance. Although this discussion and analysis refers principally to compensation for the Named Executive Officers, the same compensation principles and practices apply to all executives. The compensation of NU's Chief Executive Officer is subject to the further review and approval of the independent Trustees.

Elements of Compensation. Total direct compensation consists of three elements: base salary, annual cash incentive awards and long-term equity-based incentive awards. Indirect compensation is provided through certain retirement, perquisite, severance, and health and welfare benefit programs.

NU's Compensation Objectives. The objectives of NU's compensation program are to attract and retain superior executive talent, motivate executives to achieve annual and long-term performance goals set each year, and provide total compensation opportunities that are competitive with market practices. With respect to incentive compensation, the Committee believes it is important to balance short-term goals, such as producing earnings, with longer-term goals, such as creating long-term value and maintaining a strong balance sheet. The Committee also places great emphasis on system reliability and superior customer service. NU's compensation program utilizes performance-based incentive compensation to reward individual and corporate performance and to align the interests of executives with the company's customers and shareholders. The Committee continually increases expectations to motivate executives and employees to achieve continuous improvement in carrying out NU's responsibilities to its customers to deliver energy reliably, safely, with respect for the environment and employees, and at a reasonable cost, while providing an above-average total shareholder return to NU's shareholders.

Setting Compensation Levels. In order to ensure that the company achieves its goal of providing market-based compensation levels to attract and retain top quality management, the Committee provides executives with target compensation opportunities over time approximately equal to median compensation levels for executive officers of companies comparable to NU. To achieve that goal, the Committee and its independent compensation consultant work together to determine the market values of executive direct compensation elements (base salaries, annual incentives and long-term incentives), as well as total compensation, by using competitive market compensation data. The Committee reviews compensation data obtained from utility and general industry surveys and a specific group of peer utility companies.

Role of the Compensation Consultant. The Committee has retained Pay Governance as its independent compensation consultant. Pay Governance reports directly to the Committee and does not provide any other services to NU. With the consent of the Committee, Pay Governance works cooperatively with NU's management to develop analyses and proposals for presentation to the Committee. The Committee generally relies on Pay Governance for peer group market data and information as to market practices and trends to assess the competitiveness of the compensation NU pays to executives and to review the Committee's proposed compensation decisions.

In February 2015, the Committee assessed the independence of Pay Governance pursuant to SEC and NYSE rules and concluded that it is independent and that no conflict of interest exists that would prevent Pay Governance from independently advising the Committee. In making this assessment, the Committee considered the independence factors enumerated in Rule 10C-1(b) under the Securities Exchange Act of 1934, including the written representations of Pay Governance that Pay Governance does not provide any other services to NU, the level of fees received from NU as a percentage of Pay Governance's total revenues, the policies and procedures employed by Pay Governance to prevent conflicts of interest, and whether the individual advisers from Pay Governance with whom the Committee consulted own any NU common shares or have any business or personal relationships with members of the Committee or NU's executives.

Role of Management. The role of NU's management, and specifically the roles of NU's Chief Executive Officer and its Senior Vice President of Human Resources, is to provide current compensation information to the compensation consultant and analyses and recommendations on executive compensation to the Committee based on the market value of the position, individual performance, experience and internal pay equity. NU's Chief Executive Officer also provides recommendations on the compensation for the other Named Executive Officers. None of the executives makes recommendations that affect his or her individual compensation.

MARKET ANALYSIS

The Committee strives to provide executives with target compensation opportunities using a range that is approximately equal to the median compensation levels for executive officers of companies comparable to the Company. Set forth below is a description of the sources of the compensation data used by the Committee when reviewing 2014 compensation:

- **Utility and general industry survey data**. The Committee reviews compensation information obtained from surveys of diverse groups of utility and general industry companies that represent NU's market for executive officer talent. Utility industry data are based on a defined peer set, as discussed below. General industry data are size-adjusted to ensure a close correlation between the market data and NU's scope of operations. The Committee used this information, which it obtained from Pay Governance, to determine base salaries and incentive opportunities.

- **Peer group data.** In support of executive pay decisions during 2014, the Committee consulted with Pay Governance, which provided the Committee with a competitive assessment analysis of NU's executive compensation levels, as compared to the 20 peer group companies listed in the table below.

Alliant Energy Corporation	Edison International	Public Service Enterprise Group, Inc.
Ameren Corporation	Entergy Corporation	SCANA Corporation
CenterPoint Energy, Inc.	Integrys Energy Group, Inc.	Sempra Energy
Consolidated Edison Inc.	OGE Energy Corp.	TECO Energy, Inc.
CMS Energy Corp.	Pepco Holdings, Inc.	Wisconsin Energy Corp.
Dominion Resources, Inc.	PG&E Corp.	Xcel Energy Inc.
DTE Energy Company	PPL Corporation	

The Committee periodically adjusts the target percentages of annual and long-term incentives based on the survey data after discussion with the compensation consultant to ensure that they are approximately equal to competitive median levels.

The Committee also determines perquisites to the extent they serve business purposes and sets supplemental benefits at levels that provide market-based compensation opportunities to the executives. The Committee periodically reviews the general market for supplemental benefits and perquisites using utility and general industry survey data, including data obtained from companies in the peer group.

Mix of Compensation Elements. NU targets the mix of compensation for its Chief Executive Officer and the other Named Executive Officers so that the percentages of each compensation element are approximately equal to the competitive median market mix. The mix is heavily weighted toward incentive compensation, and incentive compensation is heavily weighted toward long-term compensation. Since the most senior positions have the greatest responsibility for implementing long-term business plans and strategies, a greater proportion of total compensation is based on performance with a long-term focus.

The Committee determines the compensation for each executive based on the relative authority, duties and responsibilities of the executive. NU's Chief Executive Officer's responsibilities for the strategic direction and daily operations and management of NU are greater than the duties and responsibilities of the other executives. As a result, the compensation of NU's Chief Executive Officer is higher than the compensation of the other executives. Assisted by the compensation consultant, the Committee regularly reviews market compensation data for executive officer positions similar to those held by the executives, including NU's Chief Executive Officer, and this market data continues to indicate that chief executive officers are paid significantly more than other executive officers.

The following tables set forth the contribution to 2014 Total Direct Compensation (TDC) of each element of compensation, at target, reflected as a percentage of TDC, for the Named Executive Officers. The amounts shown in this table are at target and therefore do not match the amounts appearing in the Summary Compensation Table.

	Percentage of TDC at Target				
			Long-Term Incentives		
Named Executive Officer (NEO)	**Base Salary**	**Annual Incentive (1)**	**Performance Shares(1)**	**RSUs(2)**	**TDC**
Thomas J. May	16%	18%	33%	33%	100%
James J. Judge	29%	19%	26%	26%	100%
Leon J. Olivier	29%	19%	26%	26%	100%
David R. McHale	29%	19%	26%	26%	100%
Werner J. Schweiger	30%	20%	25%	25%	100%
Gregory B. Butler	29%	19%	26%	26%	100%
NEO average, excluding CEO	29%	19%	26%	26%	100%

(1) The annual incentive compensation element and performance shares under the long-term incentive compensation element are performance-based.

(2) Restricted Share Units (RSUs) vest over three years contingent upon continued employment.

Risk Analysis of Executive Compensation Program. The overall compensation program includes a mix of compensation elements ranging from a fixed base salary that is risk-neutral to annual and long-term incentive compensation programs intended to motivate officers and eligible employees to achieve individual and corporate performance goals that reflect an appropriate level of risk. The fundamental objective of the compensation program is to foster the continued growth and success of the business. The design and implementation of the overall compensation program provides the Committee with opportunities throughout the year to assess risks within the compensation program that may have a material effect on NU and its shareholders.

In 2014, the Committee assessed the risks associated with the executive compensation program by reviewing the various elements of incentive compensation. The annual incentive program was designed to ensure an appropriate balance between individual and corporate goals, which were deemed appropriate and supportive of NU's annual business plan. Similarly, the long-term incentive program was designed to ensure that the performance metrics were properly weighted and supportive of NU's strategic plan. The Committee reviewed the overall compensation program in the context of the annual operating and strategic plans, which were both previously subject to Enterprise Risk Management review. Both the annual and long-term incentive programs were designed to ensure that mechanisms exist to mitigate risk. These mechanisms include realistic goal setting and discretion with respect to actual payments, the mix of financial, operational, customer service and safety goals, executive share ownership guidelines linking executive interests to those of shareholders, provisions for the clawback of incentive compensation, prohibitions on hedging and pledging of NU common shares, and the provision of limited perquisites. These mechanisms are intended to ensure that there is not undue incentive to achieve any one goal without considering the impact of achieving such goal on other aspects of NU's business.

Results of NU's 2014 Say-on-Pay Vote. NU provides its shareholders with the required opportunity to cast an annual advisory vote on executive compensation (a "Say-on-Pay" proposal). At NU's Annual Meeting of Shareholders held on May 1, 2014, 91 percent of the votes cast on the Say-on-Pay proposal were voted to approve the 2013 compensation of the Named Executive Officers, as described in NU's 2014 proxy statement. The Committee has and will continue to consider the outcome of NU's Say-on-Pay votes when making future compensation decisions for the Named Executive Officers.

ELEMENTS OF 2014 COMPENSATION

Base Salary

Base salary is designed to attract and retain key executives by providing an element of total compensation at levels competitive with those of other executives employed by companies of similar size and complexity in the utility and general industries. In establishing base salary, the Committee relies on compensation data obtained from independent third-party surveys of companies and from an industry peer group to ensure that the compensation opportunities NU offers are capable of attracting and retaining executives with the experience and talent required to achieve its strategic objectives.

When setting or adjusting base salaries, the Committee considers annual executive performance appraisals; market pay movement across industries (determined through market analysis); targeted market pay positioning for each executive; individual experience and years of service; strategic importance of a position; and internal equity.

Individuals who are performing well in strategic positions are likely to have their base salaries increased more significantly than other individuals. From time-to-time, economic conditions and corporate performance have caused base salary increases to be postponed. However, the Committee prefers to reflect sub-par corporate performance through the variable pay components.

In February 2014, the Committee adjusted the base salaries of the Named Executive Officers by 3 percent. The Committee and independent Trustees also adjusted Mr. May's base salary by 3 percent.

Incentive Compensation

Annual incentive and the long-term incentive compensation are provided under the Company's Incentive Plan, which was approved by NU's shareholders at the 2007 Annual Meeting of Shareholders and, with respect to the material terms of performance goals, was re-approved by the shareholders at the 2012 Annual Meeting of Shareholders. The annual incentive program provides cash compensation intended to reward performance under NU's annual operating plan. The long-term stock-based incentive program is designed to reward demonstrated performance and leadership, motivate future performance, align the interests of the executives with those of NU's shareholders, and retain the executives during the term of grants. The annual and long-term programs are designed to strike a balance between short- and long-term objectives so that the programs work in tandem.

2014 ANNUAL INCENTIVE PROGRAM

In February 2014, the Committee established the terms of the 2014 Annual Incentive Program. As part of the overall program, and after consulting with Pay Governance, the Committee set target award levels for each of the Named Executive Officers that ranged from 60 percent to 110 percent of target. Target award levels under the Annual Incentive Program are expressed as a percentage of base salary.

At the February 2014 meeting, the Committee determined that for 2014 it would base 70 percent of the annual incentive performance goals on NU's overall financial performance and 30 percent of the annual performance goals on NU's overall operational performance. The Committee also determined the specific goals to assess performance and that the individual goals would be assessed using ratings ranging from 0 percent to 200 percent. The Committee assigned weightings to each of these specific goals: for the financial component, the earnings per share goal was weighted at 60 percent, the reduction in operating expenses goal was weighted at 20 percent, and the remaining 20 percent weighting was based on the combined dividend growth and credit rating goals. For the operational component, the Committee determined that the combined service reliability and responsiveness goals would be weighted at 60 percent, the combined customer service and merger integration goals would be weighted at 25 percent, and the combined safety ratings, gas service response and call center performance goals would be weighted at 15 percent.

With respect to 2014 performance, management provided an initial review of the Company's performance for the year at the December 2014 meeting of the Committee, followed in February 2015 by a full assessment of the performance goals, the additional accomplishments noted below under the caption "Additional Factors" and the overall performance of NU. The Committee was also provided updates during the year on corporate performance. At the February 2015 meeting, the Committee determined, based on its assessment of the financial and operational performance goals, to set the level of achievement of combined financial and operational performance goals results at 161 percent of target, reflecting the overall excellent performance of NU and the executive team. In arriving at this determination, the Committee determined that the financial performance goals result was 163 percent of target and the operational performance goals result was 158 percent of target. The individual financial and operational performance goals results are as set forth below. NU's Chief Executive Officer recommended to the Committee payout levels for the executives (other than himself) based on his assessment of each executive's individual performance towards achievement of the performance goals and the additional accomplishments of NU, together with each executive's contributions to the overall performance of NU. The awards determined by the Committee were also based on the same three-component criteria.

Financial Performance Goals Assessment

- NU achieved its goal of recurring earnings per share of $2.65 in 2014, exclusive of merger related costs, a 4.7 percent increase over 2013 and compared to an expected industry increase of approximately 4.5 percent. The Committee determined this goal to be a significant accomplishment, particularly in light of an unfavorable ruling from the Federal Energy Regulatory Commission that lowered NU's return on equity and resulted in a $0.07 per share charge to earnings, and the fact that NU had previously grown earnings 11 percent in 2013. The Committee determined this goal to have attained a 150 percent performance result.

- NU continued to achieve operations and maintenance expense reductions through successful integration initiatives, resulting in a 6.8 percent reduction in operating expenses in 2014. This exceeded the goal of more than a 3 percent reduction and compared with an expected average industry increase of 2 percent. The Committee determined this goal to have attained a 200 percent performance result.

- NU increased its dividend to $1.57 per share, a 6.8 percent increase from the prior year and significantly above the industry average dividend growth of 3.7 percent. The Committee determined this goal to have attained a 175 percent performance result in light of both the 2014 percentage increase and the previous dividend growth realized in 2013.

- NU's credit rating at Standard & Poor's is currently "A-," among the highest in the utility industry, providing the foundation for favorable financing opportunities during the year and in the future. The industry average credit rating at Standard & Poor's is "BBB+." In addition, during the year Standard & Poor's raised the outlook on NU's credit rating to "positive" from "stable." The Committee determined this goal to have attained a 150 percent performance result.

Operational Performance Goals Assessment

- NU's total electric system operating performance was the best on record. Average months between interruptions in service equaled 15.4 months, 18 percent better than the goal of 13.1 months and exceeding the industry average of 13.2 months. System average restoration duration equaled 82 minutes, 15 percent better than the established goal of 96.1 minutes and significantly below the industry average of 123.2 minutes. Both of these results indicate top quartile performance against industry peers. The Committee determined these goals to have each attained a 175 percent performance result.

- NU completed several important integration initiatives across the company, including the implementation of an out-sourced IT business model, a new financial and reporting and budgeting general ledger system, and a facilities consolidation program that streamlined operating effectiveness. The Committee determined this goal to have attained a 150 percent performance result.

- NU continued to improve the customer experience through substantial progress on several customer initiatives, including its "Above and Beyond for our Customers-Driving To Top Tier" initiative of improving customer service; the implementation of "Blue Sky" outage information improvements; its "Voice of the Customer" program; and the creation of the exciting new brand, Eversource Energy, which captures the company's dedication to great customer service. The Committee determined this goal to have attained a 150 percent performance result.

- On-time response to gas customer emergency calls was 99.2 percent, which exceeded the goal of 99.1 percent. The Committee determined this goal to have attained a 100 percent performance result.

- 86.2 percent of customer calls were answered within 30 seconds, which exceeded the goal of 85.6 percent. The Committee determined this goal to have attained a 100 percent performance result.

- NU achieved a safety performance goal of 1.44 Days Away & Restricted Time ("DART") per 1,000 employees, exceeding the goal of 1.5. The Committee determined this goal to have attained a 100 percent performance result.

Additional Factors

The following results were also considered by the Committee in making an assessment of overall financial and operational performance, but were not given specific weightings or assigned a specific performance assessment score:

- NU announced a partnership with Spectra Energy Corp to bring much needed natural gas capacity into New England.

- NU obtained several constructive regulatory approvals and decisions in Connecticut, Massachusetts and New Hampshire.

- NU successfully completed its $1.7 billion capital plan to improve reliability and customer service and also responded very well to several major storms across its service territory.

- NU implemented important employee engagement and corporate culture initiatives and streamlined and simplified many processes across the company, in concert with its "One Company" model.

- NU's cumulative total shareholder returns of 30.5 percent, 64.3 percent, 145.8 percent, and 297.7 percent over the past one-, three-, five-, and 10-year periods outperformed the utility industry over those same periods.

Individual Performance Factors Considered by the Committee

The goal of the Committee for 2014 was to continue to provide incentives for executives to work together as a highly effective, integrated team to achieve or exceed the financial, operational, customer and process integration goals and objectives. While emphasizing the importance of executives working as a team, the annual incentive award payments were also based on the Committee's assessment of each executive's individual performance in supporting the performance goals, additional achievements and overall company performance. The Committee assessed the performance of NU's Chief Executive Officer and, based on the recommendations of the Chief Executive Officer, the Named Executive Officers, to determine the individual incentive awards as disclosed in the Summary Compensation Table. Based on the Committee's review, which included its assessment of the performance goals, the significant other accomplishments of NU and the Named Executive Officers, and the overall performance of NU and each of Named Executive Officers, considered in its totality by the Committee to have been excellent, the Committee approved annual incentive program payouts for the Named Executive Officers at levels that ranged from 154 percent to 171 percent of target. These awards reflected the individual and team contributions of Mr. May, Mr. Judge, Mr. Olivier, Mr. McHale, Mr. Schweiger and Mr. Butler in achieving the goals and the additional accomplishments and the overall performance of the company.

In arriving at Mr. May's annual incentive payment of $2,250,000, which was 170 percent of target, and which reflects his and NU's excellent performance, the Committee and the Board considered the totality of NU's success in accomplishing the financial, operational, customer and merger effectiveness goals, the additional accomplishments of the company, and Mr. May's strategic leadership of NU.

2014 Annual Incentive Program Performance Assessments

Financial Performance Goals

	Category	2014 Goal	Company Performance	Indicative Assessment
Financial Performance	Earnings Per Share	$2.65 per share	Achieved - $2.65 per share, a 4.7% increase over 2013, outperforming expected industry peer growth of approximately 4.5%	150%
	Reduce Operating Expenses	Reduce operating expenses to $1,424 million, or a more than 3% reduction	Exceeded - 2014 Operating Expenses were $1,392 million, or 6.8% below 2013 results	200%
	Dividend Growth	Increase NU's dividend $.10 to $1.57 per share	Achieved - Increased to $1.57 per share, a $.10 increase and 6.8% growth, significantly exceeding the industry average growth of 3.7%	175%
	Credit Rating	Maintain NU's top tier Standard & Poor's (S&P) A- credit rating	Achieved – S&P rating A- (with "new" Positive Outlook), among the highest in the utility industry	150%
Weightings = EPS - 60%; Reduce Operating Expenses - 20%; dividend/credit - 20%				

Operational Performance Goals

	Category	2014 Goal	Company Performance	Indicative Assessment
Operational Performance	Reliability – Avg. Months Between Interruptions (MBI)	Achieve MBI of 13.1	Exceeded - MBI 15.4; 18% better than goal and in top quartile of peers	175%
	Average Restoration Duration (SAIDI)	Achieve SAIDI of 96.1 minutes	Exceeded - SAIDI 82 minutes; 15% better than goal and in top quartile of peers	175%
	Improve the Customer Experience	Implement customer service initiatives	Achieved - Major initiatives (customer service, outage information and branding) achieved	150%
	Merger Integration	Execute on key merger integration initiatives	Achieved - Significant IT, general ledger and facilities initiatives achieved, lowering costs and streamlining operations	150%
	Safety Rate	1.5 DART	Achieved - 1.44 DART	100%
	Gas Service Response	99.1%	Achieved - 99.2%	100%
	Calls Answered	85.6%	Achieved - 86.2%	100%

Weightings = Reliability and Restoration – 60%; Important Corporate Initiatives – 25%;
Safety/Gas Service Response/Calls Answered Rate – combined 15%

Performance Goals Assessment

Financial Performance (weighted 70%)	163%
Operational Performance (weighted 30%)	158%
Overall Performance	161%

LONG-TERM INCENTIVE PROGRAM

General

NU's long-term incentive program is intended to focus on the company's longer-term strategic goals and to help retain the executives. A new three-year program commences every year. For the 2014 – 2016 Long-Term Incentive Program, at target, each grant consisted of 50 percent Restricted Share Units (RSUs) and 50 percent Performance Shares. RSUs are designed to provide executives with an incentive to increase the value of Company common shares in alignment with shareholder interests, while also serving as a retention component for executive talent. Performance Shares are designed to reward achievement as measured against pre-established performance measures. NU believes these compensation elements create a focus on continued company and NU share price growth to further align the interests of the executives with the interests of NU's shareholders.

Restricted Share Units (RSUs)

General

Each RSU granted under the long-term incentive program entitles the holder to receive one NU common share at the time of vesting. All RSUs granted under the long-term incentive program provide for vesting in equal annual installments over three years. RSU holders are eligible to receive reinvested dividend units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU common shares. Reinvested dividend units are accounted for as additional RSUs that accrue and are distributed with the common shares issued upon vesting of the underlying RSUs. Common shares, including any additional common shares in respect of reinvested dividend units, are not issued for any RSUs that do not vest.

The Committee determined RSU grants for each officer participating in the long-term incentive program. RSU grants are based on a percentage of base salary and measured in dollars. In 2014, the percentage used for each officer was based on the executive officer's position in the company and ranged from 75 percent to 200 percent of base salary. The Committee reserves the right to increase or decrease the RSU grant from target for each officer under special circumstances. Based on input from NU's Chief Executive Officer, the Committee determined the final RSU grants for each of the other executive officers, including the other Named Executive Officers.

All RSUs are granted on the date of the Committee meeting at which they are approved. RSU grants are subsequently converted from dollars into common share equivalents by dividing the value of each grant by the average closing price for NU common shares over the ten trading days prior to the date of the grant.

RSU Grants under the 2014 – 2016 Program

Under the 2014 – 2016 Program, the target RSU grant totaled approximately $7,741,835 for the 49 NU officers participating in the program. Dividing the final total RSU grant by $43.13, the average closing price of NU common shares over the ten trading days prior to the date of grant, resulted in an aggregate of 179,500 RSUs. The following RSU grants at 100 percent of target were approved, reflected in RSUs: Mr. May: 55,900; Mr. Judge: 12,400; Mr. Olivier: 13,000; Mr. McHale: 12,400; Mr. Schweiger: 8,700 and Mr. Butler: 8,600.

RSU Grants under the 2013 – 2015 Program

Under the 2013 – 2015 Program, the target RSU grant totaled approximately $7,057,248 for the 44 NU officers participating in the program. Dividing the final total RSU grant by $39.36, the average closing price of NU common shares over the ten trading days prior to the date of grant, resulted in an aggregate of 179,300 RSUs. The following RSU grants at 100 percent of target were approved, reflected in RSUs: Mr. May: 52,000; Mr. Judge: 13,100; Mr. Olivier: 13,800; Mr. McHale: 13,100; Mr. Schweiger: 9,300 and Mr. Butler: 9,100.

Performance Share Grants

General

Performance Shares are designed to reward future financial performance, measured by long-term earnings growth and above-average total shareholder returns, therefore aligning compensation with performance.

Performance Shares under the 2014 – 2016 Program

The Committee determined to use: (i) average diluted NU earnings per share growth adjusted for certain non-recurring items ("EPSG"); and (ii) relative NU total shareholder return ("TSR") measured against the performance of companies that comprise the EEI Index. As in 2013, the Committee selected EPSG and TSR as performance measures because the Committee believes that they are generally recognized as the best indicators of overall corporate performance. Further, the Committee considers it a best practice to use a combination of relative and absolute metrics, with EPS growth serving as a key input to shareholder value and TSR serving as the output.

The number of Performance Shares awarded at the end of the three-year period ranges from 0 percent to 200 percent of target, depending on EPSG and relative TSR performance as set forth in the performance matrix below. For the 2014 – 2016 Program, EPSG ranges from 0 percent to 9 percent, while TSR ranges from below the 10th percentile to approximately above the 90th percentile. The Committee determined that payout at 100 percent of target should be challenging but achievable. As a result, vesting at 100 percent of target occurs at various combinations of EPSG and TSR performance. In addition, the value of any performance shares that actually vest may increase or decrease over the vesting period based on NU's share price performance.

The performance matrix set forth below describes how the Performance Share payout is determined under the 2014 – 2016 Program. Actual three-year average EPSG is cross-referenced with the actual three-year TSR percentile to determine actual performance share payout as a percentage of target:

2014 – 2016 Long-Term Incentive Program Performance Share Payout

Three-Year Average EPS Growth	Three-Year Relative Total Shareholder Return Percentiles									
	Below 10th	20th	30th	40th	50th	60th	70th	80th	90th	Above 90th
9%	110%	120%	130%	140%	150%	160%	170%	180%	190%	200%
8%	100%	110%	120%	130%	140%	150%	160%	170%	180%	190%
7%	90%	100%	110%	120%	130%	140%	150%	160%	170%	180%
6%	80%	90%	100%	110%	120%	130%	140%	150%	160%	170%
5%	70%	80%	90%	100%	110%	120%	130%	140%	150%	160%
4%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
3%	40%	50%	70%	80%	90%	100%	110%	120%	130%	140%
2%	20%	40%	60%	70%	80%	90%	100%	110%	120%	130%
1%	0%	10%	40%	60%	70%	80%	90%	100%	110%	120%
0%	0%	0%	20%	30%	50%	70%	80%	90%	100%	110%
Below 0%	0%	0%	0%	0%	10%	20%	30%	40%	50%	60%

Performance Shares under the 2013 – 2015 Program

The Committee also determined to use: (i) EPSG; and (ii) TSR measured against the performance of companies that comprise the EEI Index. For the 2013 – 2015 Program, the number of Performance Shares awarded at the end of the three-year period ranges from 0 percent to 200 percent of target, depending on EPSG and relative TSR performance as set forth in the performance matrix. EPSG ranges from 0 percent to 10 percent, while TSR ranges from below the 10th percentile to approximately above the 90th percentile. The Committee determined that payout at 100 percent of target should be challenging but achievable. As a result, vesting at 100 percent of target occurs at various combinations of EPSG and TSR performance. In addition, the value of any performance shares that actually vest may increase or decrease over the vesting period based on the Company's share price performance.

The performance matrix set forth below describes how the Performance Share payout is determined under the 2013 – 2015 Program. Actual three-year average EPSG is cross-referenced with the actual three-year TSR percentile to determine actual performance share payout as a percentage of target:

2013 – 2015 Long-Term Incentive Program Performance Share Payout

Three-Year Average EPS Growth	Three-Year Relative Total Shareholder Return Percentiles										
	Below 10th	10th	20th	30th	40th	50th	60th	70th	80th	90th	Above 90th
10%	100%	110%	120%	130%	140%	150%	160%	170%	180%	190%	200%
9%	90%	100%	110%	120%	130%	140%	150%	160%	170%	180%	190%
8%	80%	90%	100%	110%	120%	130%	140%	150%	160%	170%	180%
7%	70%	80%	90%	100%	110%	120%	130%	140%	150%	160%	170%
6%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%	160%
5%	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
4%	40%	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%
3%	30%	40%	50%	60%	70%	80%	90%	100%	110%	120%	130%
2%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%	120%
1%	0%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%
0%	0%	0%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Below 0%	0%	0%	0%	0%	0%	10%	20%	30%	40%	50%	60%

2012 – 2014 (Pre-Merger) Long-Term Incentive Program

The 2012-2014 Program was approved prior to the 2012 merger with NSTAR. Grants under the Program consisted of 50 percent RSUs and 50 percent Performance Shares. The RSU grants under this three-year program vest in equal annual installments and are otherwise subject to the provisions set forth in the section above titled "Restricted Share Units (RSUs)." Upon the closing of the merger in 2012, the Performance Share grants under this program converted to RSUs assuming a target level of performance, and the newly converted RSUs were made subject to the vesting schedule for the original RSU grants under each program. Under the 2012 – 2014 Program, half of the newly converted RSUs vested in 2013 and the remaining half vested in 2014.

CLAWBACKS

If NU's earnings were to be restated as a result of noncompliance with accounting rules caused by fraud or misconduct, NU would require its Chief Executive Officer and Chief Financial Officer to provide reimbursements for certain incentive compensation received by each of them. To the extent that reimbursement were not required under SEC rules or NYSE listing standards, NU's Incentive Plan would require any employee whose misconduct or fraud caused such restatement, as determined by NU's Board of Trustees, to reimburse NU for any incentive compensation received by him or her.

In addition, once final rules are adopted by the SEC regarding any additional clawback requirements under the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd Frank), NU will review its clawback policy and compensation plans and, if necessary, amend them to comply with the new mandates.

NO HEDGING AND NO PLEDGING POLICY

NU has adopted a policy prohibiting the purchase of financial instruments or otherwise entering into transactions designed to have the effect of hedging or offsetting any decrease in the value of NU common shares by its Trustees and employees, including executive officers. This policy also prohibits all pledging, derivative transactions of short sales involving NU common shares or the holding of any NU common shares in a margin account.

SHARE OWNERSHIP GUIDELINES/HOLDING PERIODS

The Committee has approved share ownership guidelines to further emphasize the importance of share ownership by officers. As indicated in the table below, the guidelines call for NU's Chief Executive Officer to own NU common shares equal to six times base salary, executive vice presidents and senior vice presidents to own a number of common shares equal to three times base salary and all other officers to own a number of common shares equal to one to two times base salary.

Executive Officer	Base Salary Multiple
Chief Executive Officer	6
Executive Vice Presidents / Senior Vice Presidents	3
Operating Company Presidents	2
Vice Presidents	1-1.5

NU requires that its officers attain these ownership levels within five years. All officers, including the Named Executive Officers, have satisfied the share ownership guidelines or are expected to satisfy them within the applicable timeframe. Common shares, whether held of record, in street name, or in individual 401(k) accounts, and RSUs satisfy the guidelines. Unexercised stock options and unvested performance shares do not count toward the ownership guidelines. In addition to the share ownership guidelines requirements noted above, all officers must hold all the net shares awarded under NU's stock compensation plan until the share ownership guidelines requirements have been met. We will also review this policy when final rules under Dodd-Frank are adopted and will amend our policy and disclosure as appropriate to comply with the rules.

OTHER

Retirement Benefits

NU provides a qualified defined benefit pension program for certain officers, which is a final average pay program subject to tax code limits. Because of such limits, NU also maintains a supplemental non-qualified pension program. Benefits are based on base salary and certain incentive payments, which is consistent with the goal of providing a retirement benefit that replaces a percentage of pre-retirement income. The supplemental program makes up for benefits barred by tax code limits, and generally provides (together with the qualified pension program) benefits equal to approximately 60 percent of pre-retirement compensation (subject to certain reductions) for Messrs. May, Judge, Schweiger and Butler, and approximately 50 percent of such compensation for Mr. McHale. The supplemental program has been discontinued for newly-elected officers.

For certain participants, the benefits payable under the Supplement Non-Qualified Pension Program (Program) differ from those described above. Under the Key Executive Benefit Plan, Mr. May is entitled to an alternative retirement benefit equal to 33 percent of final base salary annually for 15 years in lieu of the benefits provided under the Program. Benefits that would be available under the Key Executive Benefit Plan are less than those available under the Program and therefore have not been included in the present value of accumulated benefit shown below. Upon retirement, Mr. May is entitled to receive the greater of the benefit payable under the Program or the Key Executive Benefit Plan. Mr. Olivier's employment agreement provides retirement benefits similar to those of a previous employer instead of the supplemental program benefits described above. Under this agreement, he will receive a pension based on a prescribed formula if he meets certain eligibility requirements. The Program benefit payable to Mr. Schweiger is fully vested and is further reduced by benefits he is entitled to receive under previous employers' retirement plans.

Also see the narrative accompanying the "Pension Benefits" table and accompanying notes for more detail on the above program.

401(k) Benefits

NU offers a qualified 401(k) program for all employees, including executives, subject to tax code limits. After applying these limits, the program provides a maximum match of up to $10,400 for Messrs. May, Judge and Schweiger, which is equal to 50 percent of the first 8 percent of eligible base salary and annual cash incentive. For Messrs. Olivier, McHale and Butler, NU provides a maximum match of up to $7,800, which is equal to 3 percent of eligible base salary and annual cash incentive.

Deferred Compensation

NU offers a non-qualified deferred compensation program for executives. In 2014, the program allowed deferral of up to 100% of base salary, annual incentives and long-term incentive awards. The program allows participants to select investment measures for deferrals based on an array of deemed investment options (including certain mutual funds and publicly traded securities).

See the Non-Qualified Deferred Compensation Table and accompanying notes for additional details on the above program.

Perquisites

NU provides executives with limited financial planning, health services, vehicle leasing and access to tickets to sporting events, perquisites that NU believes are consistent with peer companies. The current level of perquisites does not factor into decisions on total compensation.

CONTRACTUAL AGREEMENTS

NU maintains contractual agreements with all of the Named Executive Officers that provide for potential compensation in the event of certain terminations following a Change of Control. NU believes these agreements are necessary to attract and retain high quality executives and to ensure executive focus on NU business during the period leading up to a potential Change of Control. The agreements are "double-trigger" agreements that provide executives with compensation in the event of a Change of Control, while still providing an incentive to remain employed with NU for the transition period that follows.

Under the agreements, certain compensation is generally payable if, during the applicable change of control period, the executive is involuntarily terminated (other than for cause) or voluntarily terminates employment for "good reason." These agreements are described more fully below under "Potential Payments upon Termination or Change of Control."

TAX AND ACCOUNTING CONSIDERATIONS

NU's incentive plan was approved by shareholders and permits annual incentive and performance share awards intended to qualify as performance-based compensation under Section 162(m) of the Internal Revenue Code. However, NU believes that the availability of a tax deduction for forms of compensation is secondary to the goal of providing market-based compensation to attract and retain highly qualified executives. In addition, the compensation program plans were amended in 2008 to comply with Section 409A of the Internal Revenue Code.

NU has adopted the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 718, *Compensation-Stock Compensation*. In general, NU and the Committee do not take accounting considerations into account in structuring compensation arrangements.

EQUITY GRANT PRACTICES

Equity awards noted in the compensation tables are made at the February meeting of the Committee (subject to the further approval of the independent members of NU's Board of Trustees of the Chief Executive Officer's award) when the Committee also determines base salary, annual and long-term incentive compensation targets and annual incentive awards. The date of this meeting is chosen several months in advance, and therefore awards are not coordinated with the release of material non-public information.

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by CL&P's principal executive officers in 2014 (Mr. Olivier and Mr. Schweiger), principal financial officer (Mr. Judge) and the three most highly compensated executive officers other than the principal executive officers and principal financial officer serving on December 31, 2014 (Messrs. May, McHale, and Butler), determined in accordance with the applicable SEC disclosure rules (collectively, the Named Executive Officers). As explained in the footnotes below, the amounts reflect the economic benefit to each Named Executive Officer of the compensation item paid or accrued on his behalf for the fiscal year ended December 31, 2014. The compensation shown for each Named Executive Officer was for all services in all capacities to NU and its subsidiaries. All salaries, annual incentive amounts and long-term incentive amounts shown for each Named Executive Officer were paid for all services rendered to NU and its subsidiaries, including CL&P, in all capacities.

Name and Principal Position	Year	Salary ($) (4)	Stock Awards ($) (5)	Non-Equity Incentive Plan ($) (6)	Change in Pension Value and Non-Qualified Deferred Earnings ($) (7)	All Other Compen-sation ($) (8)	Total ($)
Thomas J. May (1)	2014	1,196,325	5,276,401	2,250,000	182,787	75,004	8,980,517
President and Chief	2013	1,161,250	4,263,480	2,125,000	-	111,269	7,660,999
Executive Officer of NU;	2012	1,125,000	3,418,416	2,100,000	1,232,395	91,726	7,967,537
Chairman of CL&P							
James J. Judge (1)	2014	587,975	1,170,436	660,000	1,587,879	20,346	4,026,636
Executive Vice President	2013	570,750	1,074,069	650,000	111,279	20,886	2,426,984
and Chief Financial	2012	535,667	793,045	640,000	1,097,100	21,085	3,086,897
Officer of NU and CL&P							
Leon J. Olivier (2)	2014	617,225	1,227,070	680,000	1,376,886	7,877	3,909,058
Executive Vice President	2013	599,242	1,131,462	670,000	109,818	23,668	2,534,190
Energy Enterprise	2012	583,043	889,147	974,236	887,046	17,491	3,350,963
Strategy and Business							
Development of NU							
David R. McHale	2014	587,643	1,170,436	660,000	2,136,933	10,348	4,565,360
Executive Vice President	2013	570,147	1,074,069	650,000	-	22,104	2,316,320
and Chief Administrative	2012	553,853	844,685	939,939	1,127,536	16,615	3,482,628
of NU and CL&P							
Werner J. Schweiger (3)	2014	538,950	821,193	600,000	1,174,893	205,073	3,340,109
Executive Vice President							
and Chief Operating							
Officer of NU; CEO of							
CL&P							
Gregory B. Butler	2014	457,736	811,754	515,000	1,274,208	12,800	3,071,498
Senior Vice President	2013	444,423	746,109	505,000	-	12,650	1,708,182
and General Counsel of	2012	431,885	659,226	727,534	764,758	7,500	2,590,903
NU and CL&P							

(1) The 2012 compensation reported for Messrs. May and Judge includes compensation paid by NSTAR during the period from January 1, 2012 to April 9, 2012, prior to the closing of the merger, plus compensation paid by NU for the remainder of 2012, following the closing of the merger. The 2012 compensation paid by NU consisted of the following. For Mr. May, Salary: $822,414; Non-Equity Incentive Plan Compensation: $2,100,000; Change in Pension Value and Non-Qualified Deferred Compensation Earnings: $1,232,395; All Other Compensation: $87,821; and Total: $4,242,630. For Mr. Judge, Salary: $401,215; Non-Equity Incentive Plan Compensation: $640,000; Change in Pension Value and Non-Qualified Deferred Compensation Earnings: $1,097,100; All Other Compensation: $7,500; and Total: $2,145,815.

(2) Mr. Olivier resigned as Chief Executive Officer of CL&P effective August 11, 2014, and as Executive Vice President and Chief Operating Officer of NU effective September 2, 2014. He was elected Executive Vice President-Energy Enterprise Strategy and Business Development of NU effective September 2, 2014.

(3) Mr. Schweiger was elected Chief Executive Officer of CL&P effective August 11, 2014. He did not meet the requirements for inclusion in the Summary Compensation Table and was not a Named Executive Officer in 2012 and 2013. Mr. Schweiger was elected Executive Vice President and Chief Operating Officer of NU effective September 2, 2014.

(4) Includes amounts deferred in 2014 under the deferred compensation program for Mr. Olivier: $123,446; Mr. McHale: $11,753 and Mr. Schweiger: $997,803. For more information, see the Executive Contributions in the Last Fiscal Year column of the Non-Qualified Deferred Compensation Plans Table.

(5) Reflects the aggregate grant date fair value of restricted share units (RSUs) and performance shares granted in each fiscal year, calculated in accordance with FASB ASC Topic 718.

In 2013 and 2014 for each Named Executive Officer, and in 2012 for Messrs. Olivier, McHale and Butler, RSUs were granted as long-term compensation that vest in equal annual installments over three years. RSU holders are eligible to receive dividend equivalent units on outstanding RSUs held by them to the same extent that dividends are declared and paid on our common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares issued upon vesting of the underlying RSUs. The 2012 amounts shown for Mr. May and Mr. Judge represent the value of Deferred Shares granted by NSTAR. See footnote (1).

In 2014, each of the Named Executive Officers was granted performance shares as long-term incentive compensation. These performance shares will vest on December 31, 2016 based on the extent to which the two performance conditions described in the CD&A are achieved. The grant date values for the performance shares, assuming achievement of the highest level of both performance conditions, are as follows: Mr. May: $4,112,004; Mr. Judge: $912,144; Mr. Olivier: $956,280 Mr. McHale: $912,144; Mr. Schweiger: $639,972; and Mr. Butler: $632,616.

(6) Includes payments to the Named Executive Officers under the 2014 Annual Incentive Program (Mr. May: $2,250,000; Mr. Judge: $660,000; Mr. Olivier: $680,000; Mr. McHale: $660,000; Mr. Schweiger: $600,000 and Mr. Butler: $515,000).

(7) Includes the actuarial increase in the present value from December 31, 2013 to December 31, 2014, of the Named Executive Officer's accumulated benefits under all of our defined benefit pension program and agreements determined using interest rate and mortality rate assumptions consistent with those appearing under the caption "Management's Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K. The Named Executive Officer may not be fully vested in such amounts. More information on this topic is set forth with respect to the Pension Benefits table, appearing further below. There were no above-market earnings on deferrals in 2014, as the terms of the Deferred Compensation Plan provide for market-based investments, including Company Common Shares. In 2013, the change in pension value for each of Messrs. May, McHale and Butler was a negative amount.

(8) Includes matching contributions allocated by us to the accounts of Named Executive Officers under the 401k plan as follows: $10,400 for each of Messrs. May, Judge and Schweiger, and $7,800 for each of Messrs. Olivier, McHale and Butler. Also includes employer matching contributions under the deferred compensation program for eligible Named Executive Officers who made deferral elections in late 2013 for salary earned in 2014 (Mr. McHale: $9,827 and Mr. Olivier: $10,737). Mr. Butler did not participate in the deferred compensation program in 2014. For Mr. May, the value shown includes $53,118 attributable to a previously granted $6.155 million present value life insurance benefit; financial planning services valued at $5,860; $3,086 paid by the Company for Company-leased vehicles. For Mr. Judge, the value shown includes financial planning services valued at $6,100 and $3,846 paid by the Company for Company-leased vehicles. For Mr. Schweiger, the value shown includes financial planning services valued at $6,028, $802 paid by the Company for Company-leased vehicles and $187,843 paid by the Company for relocation from Massachusetts to Connecticut. None of the other Named Executive Officers received perquisites valued in the aggregate in excess of $10,000.

GRANTS OF PLAN-BASED AWARDS DURING 2014

The Grants of Plan-Based Awards Table provides information on the range of potential payouts under all incentive plan awards during the fiscal year ended December 31, 2014. The table also discloses the underlying equity awards and the grant date for equity-based awards. NU has not granted any stock options since 2002.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold ($)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Target ($)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards [(1)] Threshold ($)	Estimated Future Payouts Under Equity Incentive Plan Awards [(1)] Target (#)	Estimated Future Payouts Under Equity Incentive Plan Awards [(1)] Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#) (2)	Grant Date Fair Value of Stock and Option Awards ($) (3)
Thomas J. May									
Annual Incentive [(4)]	02/04/2014	662,800	1,325,600	2,651,200	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	55,900	111,800	55,900	5,276,401
James J. Judge									
Annual Incentive [(4)]	02/04/2014	192,500	385,000	770,000	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	12,400	24,800	12,400	1,170,436
Leon J. Olivier									
Annual Incentive [(4)]	02/04/2014	202,000	404,000	808,000	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	13,000	26,000	13,000	1,227,070
David R. McHale									
Annual Incentive [(4)]	02/04/2014	192,500	385,000	770,000	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	12,400	24,800	12,400	1,170,436
Werner J. Schweiger									
Annual Incentive [(4)]	02/04/2014	195,000	390,000	780,000	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	8,700	17,400	8,700	821,193
Gregory B. Butler									
Annual Incentive [(4)]	02/04/2014	149,955	299,910	599,820	—	—	—	—	—
Long-Term Incentive [(5)]	02/04/2014	—	—	—	—	8,600	17,200	8,600	811,754

(1) Reflects the number of performance shares granted to each of the Named Executive Officers on February 4, 2014 under the 2014 – 2016 Long-Term Incentive Program. Performance shares were granted subject to a three-year Performance Period that ends on December 31, 2016. At the end of the Performance Period, common shares will be awarded based on actual performance as a percentage of target, subject to reduction for applicable withholding taxes. Holders of performance shares are eligible to receive dividend equivalent units on outstanding performance shares held by them to the same extent that dividends are declared and paid on our common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with NU common shares underlying the performance shares. The Annual Incentive Plan does not include an equity component.

(2) Reflects the number of RSUs granted to each of the Named Executive Officers on February 4, 2014 under the 2014 – 2016 Long-Term Incentive Program. RSUs vest in equal installments on February 4, 2015, 2016 and 2017. NU will distribute common shares with respect to vested RSUs on a one-for-one basis following vesting, after reduction for applicable withholding taxes. Holders of RSUs are eligible to receive dividend equivalent units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with the NU common shares distributed in respect of the underlying RSUs.

(3) Reflects the grant-date fair value, determined in accordance with FASB ASC Topic 718, of RSUs and performance shares granted to the Named Executive Officers on February 4, 2014 under the 2014 – 2016 Long-Term Incentive Program.

(4) Amounts reflect the range of potential payouts, if any, under the 2014 Annual Incentive Program for each Named Executive Officer, as described in the CD&A. The payment in 2015 for performance in 2014 is set forth in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. The threshold payment under the Annual Incentive Program is 50 percent of target.

(5) Reflects the range of potential payouts, if any, pursuant to performance share awards under the 2014 – 2016 Long-Term Incentive Program, as described in the CD&A.

EQUITY GRANTS OUTSTANDING AT DECEMBER 31, 2014

The following table sets forth option and RSU grants outstanding at the end of our fiscal year ended December 31, 2014 for each of the Named Executive Officers. All outstanding options were fully vested as of April 10, 2012.

	Option Awards (1)			Stock Awards (2)			
Name	Number of Securities Underlying Unexercised Options Exercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that have not Vested (#) (3)	Market Value of Shares or Units of Stock that have not Vested ($) (4)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Thomas J. May	174,496	26.9000	1/28/2020	—	—	—	—
	—	—	—	130,903	7,005,912	113,412	6,069,810
James J. Judge	—	—	—	107,782	5,768,468	26,832	1,436,049
Leon J. Olivier	—	—	—	88,063	4,713,154	28,201	1,509,318
David R. McHale	—	—	—	104,935	5,616,122	26,832	1,436,049
Werner J. Schweiger	47,232	28.1200	5/3/2017	—	—	—	—
	39,360	24.7400	1/24/2018	—	—	—	—
	48,544	25.9300	1/22/2019	—	—	—	—
	36,736	26.9000	1/28/2020	—	—	—	—
	—	—	—	92,021	4,924,953	18,942	1,013,776
Gregory B. Butler	—	—	—	77,732	4,160,216	18,625	996,810

(1) Options held by Mr. May and Mr. Schweiger were granted by NSTAR before the Merger and assumed by NU upon completion of the Merger.

(2) Awards and market values of awards appearing in the table and the accompanying notes have been rounded to whole units.

(3) A total of 154,815 unvested RSUs vested after January 1 and on or before February 25, 2015 (Mr. May: 73,839 and Mr. Judge: 17,304; Mr. Olivier: 18,804; Mr. McHale: 17,878; Mr. Schweiger: 13,810 and Mr. Butler: 13,180). A total of 77,616 unvested RSUs will vest on February 4, 2016 (Mr. May: 37,805; Mr. Judge: 8,944; Mr. Olivier: 9,400; Mr. McHale: 8,944; Mr. Schweiger: 6,314 and Mr. Butler: 6,209). A total of 38,244 unvested RSUs will vest on February 4, 2017 (Mr. May: 19,259; Mr. Judge: 4,273; Mr. Olivier: 4,479; Mr. McHale: 4,273; Mr. Schweiger: 2,997 and Mr. Butler: 2,963).

In connection with the Merger, in November 2010, NU and NSTAR each established retention pools in an aggregate amount of $10 million to be allocated to key employees, including certain executive officers, to help ensure their continued dedication to each company both before and after completion of the Merger. Awards were in the form of RSUs and generally vest subject to three years of continuous service following completion of the Merger. Full payment will also be made if an eligible executive dies, becomes disabled, or is terminated by NU without "cause" before the end of the retention period, in which case the retention payment will be reduced by the amount of any cash severance payable to the executive upon or during the year following termination. Awards granted to former NSTAR executive officers were assumed by NU upon completion of the Merger. An additional 330,760 unvested RSUs granted pursuant to the retention pools will vest on April 10, 2015, subject to three years of continuous service following completion of the Merger (Mr. Judge: 77,260; Mr. Olivier: 55,380; Mr. McHale: 73,840; Mr. Schweiger: 68,900 and Mr. Butler: 55,380). Mr. May did not participate in this program.

(4) The market value of RSUs is determined by multiplying the number of RSUs by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

(5) Reflects the target payout level for 2014 performance shares. The payout for 2014 performance shares will be based on actual performance as a percentage of target, subject to reduction for applicable withholding taxes. As described more fully under "Performance Shares" in the CD&A and footnote (1) to the Grants of Plan-Based Awards table, performance shares will vest following a three-year performance period based on the extent to which the two 2014 performance conditions are achieved. A total of 118,149 unearned performance shares (including accrued dividend equivalents) will vest on December 31, 2016, assuming achievement of these conditions at a target level of performance: (Mr. May: 55,638; Mr. Judge: 14,016; Mr. Olivier: 14,765; Mr. McHale: 14,016; Mr. Schweiger: 9,951 and Mr. Butler: 9,763).

(6) The market value is determined by multiplying the number of performance shares in the adjacent column by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

OPTIONS EXERCISED AND STOCK VESTED IN 2014

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2014. The Stock Awards columns report the vesting of RSU grants to the Named Executive Officers in 2014.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise ($) (1)	Number of Shares Acquired on Vesting (#) (2)	Value Realized on Vesting ($) (3)
Thomas J. May	649,440	11,654,253	90,002	3,864,352
James J. Judge	—	—	20,884	897,582
Leon J. Olivier	—	—	23,479	1,055,842
David R. McHale	—	—	22,300	1,002,842
Werner J. Schweiger	141,696	3,595,413	18,178	779,454
Gregory B. Butler	—	—	16,982	763,701

(1) Represents the amounts realized upon option exercises, which is the difference between the option exercise price and the market price at the time of exercise.

(2) Includes RSUs granted to the Named Executive Officers under NU's long-term incentive programs, including dividend reinvestments, as follows:

Name	2011 Program	2012 Program	2013 Program	2014 Program
Thomas J. May	37,191	34,867	17,944	—
James J. Judge	8,275	8,089	4,520	—
Leon J. Olivier	9,618	9,099	4,762	—
David R. McHale	9,136	8,644	4,520	—
Werner J. Schweiger	7,717	7,252	3,209	—
Gregory B. Butler	7,097	6,746	3,140	—

In all cases, the distribution of common shares is reduced by that number of shares valued in an amount sufficient to satisfy tax withholding obligations, which amount is distributed in cash.

(3) Values realized on vesting for Messrs. May, Judge and Schweiger are based on $42.43 per share, the closing price of NU common shares on January 28, 2014 and $44.97 per share, the closing price of NU common shares on February 18, 2014. Values realized on vesting for Messrs. Olivier, McHale and Butler are based on $44.42 per share, the closing price of NU common shares on February 25, 2014.

PENSION BENEFITS IN 2014

The Pension Benefits Table shows the estimated present value of accumulated retirement benefits payable to each Named Executive Officer upon retirement based on the assumptions described below. The table distinguishes between benefits available under the qualified pension program, the supplemental pension program, and any additional benefits available under contractual agreements. See the narrative above in the Compensation Discussion and Analysis under the caption "OTHER- Retirement Benefits" and "CONTRACTUAL AGREEMENTS" for more detail on benefits under these plans and our agreements.

The values shown in the Pension Benefits Table for Messrs. May and Judge were calculated as of December 31, 2014 based on benefit payments in the form of a lump sum. For Mr. McHale, a payment of benefits in the form of a one-half spousal contingent annuitant option was assumed. The Compensation Committee and the Board of Trustees approved a resolution in February of 2014 providing that the net present value of Mr. May's pension program benefit will be not less than the amount that represents the value of his earned pension program benefit as of December 31, 2012, the end of the year that Mr. May reached retirement age. The retirement benefit equaled $23.05 million at that date. Such earned pension program benefit value could otherwise change in the future because of the reduction in mortality factors and the potentially rising interest rates. For Mr. Olivier, both a lump sum payment of his special retirement benefits under his agreement, and payment of his qualified pension program benefit as a life annuity with a one-third spousal contingent annuitant option (the typical payment form under that Plan) were assumed.

The values shown in this Table for the Named Executive Officers were based on benefit payments commencing at the earliest possible ages for retirement with unreduced benefits: Mr. May: age 67, Mr. Judge: age 60, Mr. Olivier: age 60, Mr. McHale: age 60, Mr. Schweiger: age 60, Mr. Butler: age 62.

In addition, benefits under the qualified pension program were determined using tax code limits in effect on December 31, 2014. For Messrs. May, Judge and Schweiger, the values shown reflect actual 2014 salary and annual incentives earned in 2013 but paid in 2014 (per applicable supplemental program rules). For Messrs. McHale and Butler, the values shown reflect actual 2014 salary and annual incentives earned in 2014 but paid in 2015 (per applicable supplemental program rules).

The present value of benefits at retirement age was determined using the discount rate of 4.2 percent under ASC 715 for the 2014 fiscal year end measurement (as of December 31, 2014). This present value assumes no pre-retirement mortality, turnover or disability. However, for the postretirement period beginning at retirement age, we used the RP2000 Combined Healthy mortality table (the 1983 Group Annuity Mortality Table for Mr. Olivier per his agreement) as published by the Society of Actuaries projected to 2013 with projection scale AA, which is the same table used

for financial reporting under ASC 715. Additional assumptions appear under the caption "Management's Discussion and Analysis and Results of Operations" in this Annual Report on Form 10-K.

Pension Benefits

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulation Benefit ($)	During Last Fiscal Year ($)
Thomas J. May	Retirement Plan	38.5	2,332,334	—
	Supplemental Plan	20	6,201,263	—
	Supplemental Plan	38.5	14,704,089	—
James Judge	Retirement Plan	37.33	2,486,559	—
	Supplemental Plan	20	4,642,887	—
	Supplemental Plan	37.33	2,671,550	—
Leon J. Olivier (1)	Retirement Plan	15.8	702,330	—
	Supplemental Plan	13.3	5,304,563	—
	Special Retirement Benefit	31.2	1,266,068	105,966
David R. McHale	Retirement Plan	33.3	1,562,280	—
	Supplemental Plan	33.3	5,994,100	—
Werner J. Schweiger	Retirement Plan	12.83	364,217	—
	Supplemental Plan	12.83	3,860,859	—
	Supplemental Plan	12.83	1,131,928	—
Gregory B. Butler	Retirement Plan	18	815,603	—
	Supplemental Plan	18	2,314,489	—

(1) Mr. Olivier was employed with Northeast Nuclear Energy Company, one of NU's subsidiaries, from October of 1998 through March of 2001. In connection with this employment, he received a special retirement benefit that provided credit for service with his previous employer, Boston Edison Company (BECO), when calculating the value of his defined benefit pension, offset by the pension benefit provided by BECO. The benefit, which commenced upon Mr. Olivier's 55th birthday, provides an annuity of $105,966 per year in a form that provides no contingent annuitant benefit. The present value of future payments under this benefit was calculated using the actuarial assumptions currently used by the pension program. Mr. Olivier was rehired by NU from Entergy in September 2001. Mr. Olivier's current employment agreement provides for certain supplemental pension benefits in lieu of benefits under the supplemental program, in order to provide a benefit similar to that provided by Entergy. Under this arrangement, Mr. Olivier is eligible to receive a supplemental benefit, consisting of three percent of final average compensation for each of his first 15 years of service since September 10, 2001, plus one percent of final average compensation for each of the second 15 years of service. Alternatively, if Mr. Olivier voluntarily terminates his employment with NU, he is eligible to receive upon retirement a lump sum payment of $2,050,000 in lieu of benefits under the supplemental program and the benefit described in the preceding sentence. These supplemental pension benefits will be offset by the value of any benefits he receives from the pension program. Amounts reported in the table assume the termination of his employment with our consent on December 31, 2014, and payment of the lump sum benefit of $4,062,892 offset by pension program benefits.

NONQUALIFIED DEFERRED COMPENSATION IN 2014

See the narrative above in the Compensation Discussion and Analysis under the caption "ELEMENTS OF 2014 COMPENSATION - OTHER-Deferred Compensation" for more detail on our non-qualified deferred compensation program.

Name	Executive Contributions in Last FY ($) (1)	Registrant Contributions in Last FY ($) (2)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($) (3)	Aggregate Balance at Last FYE ($) (4)
Thomas J. May	—	—	11,669,293	—	56,633,176
James J. Judge	—	—	1,008,682	—	4,380,935
Leon J. Olivier	123,446	10,737	186,165	—	2,901,959
David R. McHale	11,753	9,827	12,726	—	116,362
Werner J. Schweiger	997,803	—	1,457,325	—	13,782,734
Gregory B. Butler	—	—	2,826	—	16,087

(1) Includes deferrals under the deferred compensation program (Mr. Olivier: $123,146; Mr. McHale: $11,753 and Mr. Schweiger: $997,803). Named Executive Officers who participate in this program are provided with a variety of investment opportunities, which the individual can modify and reallocate under the program terms. Contributions by the Named Executive Officer are vested at all times; however, the applicable employer matching contribution vests after three years and will be forfeited if the executive's employment terminates, other than for retirement, death or disability, prior to vesting, but will become fully vested upon a change of control. The amounts reported in this column for each Named Executive Officer are reflected as compensation to such Named Executive Officer in the Summary Compensation Table.

(2) Includes employer matching contributions made by NU under the deferred compensation program as of December 31, 2014 and posted on January 31, 2015, as reported in the All Other Compensation column of the Summary Compensation Table: (Mr. Olivier: $10,737 and Mr. McHale: $9,827). The employer matching contribution is deemed to be invested in common shares but is paid in cash at the time of distribution.

(3) Includes the total market value of deferred compensation program balances at December 31, 2014, plus the value of vested RSUs or other awards for which the distribution of common shares is currently deferred, based on $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year. The aggregate balances reflect a significant level of earnings on previously earned and deferred compensation.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

Generally, a "change of control" means a change in ownership or control of NU effected through (i) the acquisition of 20 percent or more of the combined voting power of common shares or other voting securities (30 percent for Messrs. May, Judge and Schweiger, excluding certain defined transactions), (ii) the acquisition of more than 50 percent of common shares excluding certain defined transactions (for Messrs. May, Judge and Schweiger), (iii) a change in the majority of NU's Board of Trustees, unless approved by a majority of the incumbent Trustees, (iv) certain reorganizations, mergers or consolidations where substantially all of the persons who were the beneficial owners of the outstanding common shares immediately prior to such business combination do not beneficially own more than 50 percent (75 percent for Mr. Olivier) of the voting power of the resulting business entity (excluding in certain cases defined transactions), and (v) complete liquidation or dissolution of NU, or a sale or disposition of all or substantially all of the assets of NU other than, for Messrs. McHale and Butler, to an entity with respect to which following completion of the transaction more than 50 percent (75 percent for Mr. Olivier) of common shares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction.

In the event of a change of control, the Named Executive Officers are generally entitled to receive compensation and benefits following either involuntary termination of employment without "cause" or voluntary termination of employment for "good reason" within the applicable period (generally two years following change of control or shareholder approval thereof). The Committee believes that termination for good reason is conceptually the same as termination "without cause" and, in the absence of this provision, potential acquirers would have an incentive to constructively terminate executives to avoid paying severance. Termination for "cause" generally means termination due to a felony or certain other convictions; fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to Company property; gross misconduct or gross negligence in the course of employment or gross neglect of duties harmful to the Company; or a material breach of obligations under the agreement. "Good reason" for termination generally exists after assignment of duties inconsistent with executive's position, a material reduction in compensation or benefits, a transfer more than 50 miles from the executive's pre-change of control principal business location (or for Messrs. May, Judge and Schweiger, an involuntary transfer outside the Greater Boston Metropolitan Area), or requiring business travel to a substantially greater extent than required pre-change of control (for Messrs. May, Judge and Schweiger).

The discussion and tables below show compensation payable to each Named Executive Officer, in the event of: (i) termination for cause; (ii) voluntary termination; (iii) involuntary not-for-cause termination; (iv) termination in the event of disability; (v) death; and (vi) termination following change of control. The amounts shown assume that each termination was effective as of December 31, 2014, the last business day of the fiscal year.

The summaries above do not purport to be complete and are qualified in their entirety by the actual terms and provisions of the agreements and plans, copies of which have been filed as exhibits to this Annual Report on Form 10-K.

Payments Upon Termination

Regardless of the manner in which the employment of a Named Executive Officer terminates, he is entitled to receive certain amounts earned during his term of employment. Such amounts include:

- Vested RSUs and certain other vested awards;
- Amounts contributed and any vested matching contributions under the deferred compensation program;
- Pay for unused vacation; and
- Amounts accrued and vested under the pension/supplemental and 401k programs (except in the event of a termination for cause under the supplemental program).

See the section above captioned "PENSION BENEFITS IN 2014" for information about the pension program, supplemental program and other benefits, and the section captioned "NONQUALIFIED DEFERRED COMPENSATION IN 2014."

I. Post-Employment Compensation: Termination for Cause

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives	–	–	–	–	–	–
Performance Shares	–	–	–	–	–	–
RSUs	–	–	–	–	–	–
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	–	–
Special Retirement Benefit (1)	–	–	1,266,086	–	–	–
Deferral Plan	–	–	–	–	–	–
Other Benefits						
Health and Welfare Cash Value	–	–	–	–	–	–
Perquisites	–	–	–	–	–	–
Separation Payments						
Excise Tax & Gross-Up	–	–	–	–	–	–
Separation Payment for Non-Compete Agreement	–	–	–	–	–	–
Separation Payment for Liquidated Damages	–	–	–	–	–	–
Total	—	—	1,266,086	—	—	—

(1) Represents actuarial present values at year-end 2014 of amounts payable solely under Mr. Olivier's employment agreement upon termination (which are in addition to amounts due under the pension program). Under Mr. Olivier's agreement, he would receive upon termination a lump sum payment of $2,050,000, offset by the value of pension program benefits.

II. Post-Employment Compensation: Voluntary Termination

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives (1)	2,250,000	660,000	680,000	660,000	600,000	515,000
Performance Shares (2)	6,069,829	728,740	1,509,336	–	515,450	505,971
RSUs (3)	4,819,597	438,797	1,689,294	–	309,770	646,586
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	–	–
Special Retirement Benefit (4)	–	–	1,266,086	–	–	–
Deferral Plan	–	–	–	–	–	–
Other Benefits						
Health and Welfare Benefits	–	–	–	–	–	–
Perquisites	–	–	–	–	–	–
Separation Payments						
Excise Tax & Gross-Up	–	–	–	–	–	–
Separation Payment for Non-Compete Agreement	–	–	–	–	–	–
Separation Payment for Liquidated Damages	–	–	–	–	–	–
Total	13,139,426	1,827,537	5,144,716	660,000	1,425,220	1,667,557

(1) Represents actual 2014 annual incentive awards, determined as described in the CD&A.

(2) Represents performance share awards under the 2014 – 2016 Long-Term Incentive Program.

(3) Represents values of RSUs granted to the Named Executive Officers under NU's long-term incentive programs that, at year-end 2014, were unvested under applicable vesting schedules. Under these programs, RSUs vest pro rata based on credited service years and age at termination, and time worked during the vesting period. The values were calculated by multiplying the number of RSUs by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year. Excludes retention pool RSU grants, which would not vest upon voluntary termination.

(4) Represents actuarial present values at year-end 2014 of amounts payable solely under employment agreements (which are in addition to amounts due under the pension program). Under Mr. Olivier's agreement, he would receive a lump sum payment of $2,050,000, offset by the value of pension program benefits. Amounts shown are year-end 2014 present values payable upon termination.

III. Post-Employment Compensation: Involuntary Termination, Not for Cause

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives (1)	2,250,000	660,000	680,000	660,000	600,000	515,000
Performance Shares (2)	6,069,829	728,740	1,509,336	–	515,450	505,971
RSUs (3)	6,748,237	5,021,218	4,653,230	1,997,345	4,398,447	2,087,901
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	–	–
Special Retirement Benefit (4)	–	–	1,266,086	4,063,886	–	3,570,713
Deferral Plan (5)	–	–	–	104,938	–	–
Other Benefits						
Health and Welfare Benefits (6)	–	–	–	41,962	–	41,564
Perquisites (7)	–	–	–	10,000	–	10,000
Separation Payments						
Excise Tax & Gross-Up	–	–	–	–	–	–
Separation Payment for Non-Compete Agreement (8)	–		–	977,295	–	761,310
Separation Payment for Liquidated Damages (9)	–	–	–	977,295	–	761,310
Total	15,068,066	6,409,958	8,108,652	8,832,721	5,513,897	8,253,769

(1) Represents actual 2014 Named Executive Officer annual incentive awards, determined as described in the Compensation Discussion and Analysis.

(2) Represents performance share awards under the 2014 - 2016 Long-Term Incentive Program.

(3) Represents values of RSUs under our long-term incentive programs that, at year-end 2014, were unvested under applicable vesting schedules. Under these programs, RSUs vest pro rata based on credited service years and age at termination, and time worked during the vesting period. Under the retention program, RSUs vest fully upon termination without cause and the value is reduced by separation payments. The values were calculated by multiplying the number of RSUs by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

(4) Represents actuarial present values at year-end 2014 of amounts payable solely under employment agreements upon termination (which are in addition to amounts due under the pension program). Mr. Olivier's agreement provides for a lump sum payment of $5,304,563 offset by the value of pension program benefits. Agreements with Messrs. McHale and Butler provide for two years age and service credit under the supplemental program.

(5) Represents value of NU matching contributions under the deferred compensation program that were unvested under applicable vesting schedules (other amounts in this program represent previously vested NU matching contributions, where applicable, and earned compensation contributed by executives).

(6) Represents estimated costs to NU at year-end 2014 of providing post-employment welfare benefits beyond those available to non-executives upon involuntary termination. The amount reported in the table for Messrs. McHale and Butler represents (a) the value of two years employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) a payment to offset any taxes thereon (gross-up).

(7) Represents the cost to NU of reimbursing Messrs. McHale and Butler for two years financial planning and tax preparation fees.

(8) Represents consideration for agreements not to compete with NU following termination. Employment agreements with these executives provide for a lump-sum payment equal to the sum of their base salary plus annual incentive award. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(9) Represents severance payments in addition to any non-compete agreement payments described in the prior note.

IV. Post-Employment Compensation: Termination Upon Disability

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives (1)	2,250,000	660,000	680,000	660,000	600,000	515,000
Performance Shares (2)	6,069,829	728,740	1,509,336	728,740	515,450	505,971
RSUs and Other Awards (3)	6,748,237	5,021,218	4,653,230	4,829,027	4,398,447	3,610,521
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	–	–
Special Retirement Benefit (4)	–	–	1,266,086	–	–	–
Deferral Plan (5)	–	–	–	116,768	–	–
Other Benefits						
Health and Welfare Benefits	–	–	–	–	–	–
Perquisites	–	–	–	–	–	–
Separation Payments						
Excise Tax & Gross-Up	–	–	–	–	–	–
Separation Payment for Non-Compete Agreement	–	–	–	–	–	–
Separation Payment for Liquidated Damages	–	–	–	–	–	–
Total	15,068,066	6,409,958	8,108,652	6,334,535	5,513,897	4,631,492

(1) Represents actual 2014 Named Executive Officer annual incentive awards, determined as described in the CD&A.

(2) Represents performance share awards under the 2014 – 2016 Long-Term Incentive Program.

(3) Represents values of RSUs and other awards under our long-term incentive programs and retention awards that, at year-end 2014, were unvested under applicable vesting schedules. Under these programs and awards, upon termination due to disability, awards vest in full or on a prorated basis based on credited service years and age at termination, and time worked during the vesting period. The values were calculated by multiplying the number of RSUs by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

(4) Represents the actuarial present values at the end of 2014 of the amounts payable solely as the result of employment agreements upon termination (which are in addition to amounts payable under the pension program). Under Mr. Olivier's agreement, a disability termination results in a lump sum payment of $5,304,563 offset by the value of pension program benefits.

(5) Represents value of NU matching contributions under the deferred compensation program that were unvested under applicable vesting schedules (other amounts in this program represent previously vested NU matching contributions, where applicable, and earned compensation contributed by executives).

V. Post-Employment Compensation: Death

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives (1)	2,250,000	660,000	680,000	660,000	600,000	515,000
Performance Shares (2)	6,069,829	728,740	1,509,336	728,740	515,450	505,971
RSUs and Other Awards (3)	6,748,237	5,021,218	4,653,230	4,829,027	4,398,447	3,610,521
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	–	–
Special Retirement Benefit (4)	–	–	1,266,086	–	–	–
Deferral Plan (5)	–	–	–	116,768	–	–
Other Benefits						
Health and Welfare Benefits	–	–	–	–	–	–
Perquisites	–	–	–	–	–	–
Separation Payments						
Excise Tax & Gross-Up	–	–	–	–	–	–
Separation Payment for Non-Compete Agreement	–	–	–	–	–	–
Separation Payment for Liquidated Damages	–	–	–	–	–	–
Total	15,068,066	6,409,958	8,108,652	6,334,535	5,513,897	4,631,492

(1) Represents actual 2014 Named Executive Officer annual incentive awards, determined as described in the CD&A.

(2) Represents performance share awards under the 2014 – 2016 Long-Term Incentive Program.

(3) Represents values of RSUs and other awards under our long-term incentive programs and retention awards that, at year-end 2014, were unvested under applicable vesting schedules. Under these programs and awards, upon termination due to death, awards vest in full or are prorated based on credited service years and age at termination, and time worked during the vesting period. The values were calculated by multiplying the number of RSUs by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

(4) Represents the actuarial present values at the end of 2014 of the amounts payable to a surviving spouse solely under agreements (which are in addition to amounts due under the pension program). Under Mr. Olivier's agreement, this benefit would be a lump sum payment of $5,304,563, offset by the value of pension program benefits. Pension amounts shown in the table are year-end 2014 present values of benefits immediately payable to the spouse or estate.

(5) Represents value of NU matching contributions under the deferred compensation program that were unvested under applicable vesting schedules (other amounts in this program represent previously vested NU matching contributions, where applicable, and earned compensation contributed by executives).

Payments Made Upon a Change of Control

The agreements with Messrs. May, Judge, McHale, Schweiger and Butler include change of control benefits. Mr. Olivier participates in the Special Severance Program for Officers (SSP), which also provides change of control benefits. The agreements and the SSP are binding on NU and on certain of its majority-owned subsidiaries, including CL&P.

Pursuant to the agreements and the SSP, if an involuntary non-"cause" termination of employment occurs following a change of control (see definition of "cause" above under the heading of "POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL"), or in the event of a voluntary termination for "good reason" (as described above under such heading), then the Named Executive Officers generally will receive the benefits listed below:

- For Messrs. May, Judge and Schweiger, a lump sum severance payment of three-times (two-times for Messrs. McHale and Butler, and one-time for Mr. Olivier) the sum of the executive's base salary plus annual incentive award for the relevant year (Base Compensation), plus for Messrs. McHale and Butler consideration for two year non-compete and non-solicitation covenants (one year covenant for Mr. Olivier) in the form of a lump sum payment equal to Base Compensation;

- Three years health benefits continuation (two years for Mr. Olivier);

- For Messrs. McHale and Butler, three years additional age and service credit under the applicable supplemental pension program (a lump sum payment equal to the value of such credit under that program and the pension program for Messrs. May and Judge);

- Automatic vesting and distribution of long-term performance awards (with performance shares vesting at target) and certain other awards; and

- A lump sum equal to any excise taxes incurred under the Internal Revenue Code due to receipt of change of control payments, plus an amount to offset any taxes incurred on such payments (gross-up) except for Mr. Olivier. NU has discontinued the practice of providing such gross-up payments in contractual agreements for newly elected executives.

For Messrs. McHale and Butler, the Merger did not constitute a change of control under their agreements. For Mr. Olivier, no compensation or benefits will be payable unless employment terminates during the applicable change of control period in the circumstances described below. For Messrs. May, Judge and Schweiger, in accordance with terms established by the NSTAR Executive Personnel Committee subsequent to the execution of the Merger Agreement between NU and NSTAR, and notwithstanding the terms of the NSTAR Long Term Incentive Plan, which called for outstanding and unvested stock awards to vest upon a change of control, the 2012 NSTAR performance awards did not vest upon the closing of the Merger, but were instead converted to RSUs and were made subject to the same vesting schedule as NU RSUs. No other benefits will be payable to these executives unless employment terminates during the applicable period in the circumstances described below.

The above summaries do not purport to be complete and are qualified in their entirety by the actual terms and provisions of the agreements and programs (including component plans), copies of which have been filed as exhibits to this Annual Report on Form 10-K (where applicable).

VI. Post-Employment Compensation: Termination Following a Change of Control

Type of Payment	May ($)	Judge ($)	Olivier ($)	McHale ($)	Schweiger ($)	Butler ($)
Incentive Programs						
Annual Incentives (1)	2,250,000	660,000	680,000	660,000	600,000	515,000
Performance Shares (2)	6,069,829	1,436,063	1,509,336	1,436,063	1,013,794	996,810
RSUs and Other Awards (3)	7,005,912	1,633,477	2,660,224	2,684,237	1,237,429	1,876,286
Pension and Deferred Compensation						
Supplemental Plan	–	–	–	–	—	–
Special Retirement Benefit (4)	1,585,764	1,178,500	1,266,086	8,031,236	2,452,541	4,171,891
Deferral Plan (5)	–	–	–	116,768	—	–
Other Benefits						
Health and Welfare Benefits (6)	30,168	63,054	27,864	62,942	63,429	62,345
Perquisites (7)	17,580	18,300	–	15,000	18,084	15,000
Separation Payments						
Excise Tax and Gross-Up (8)	–	–	–	7,797,762	—	3,226,193
Separation Payment for Non-Compete Agreement (9)	–	–	1,026,465	977,295	—	761,310
Separation Payment for Liquidated Damages (10)	9,990,300	3,726,900	1,026,465	1,954,590	3,450,000	1,522,620
Total	26,949,553	8,716,294	8,196,440	23,735,893	8,835,277	13,147,455

(1) Represents actual 2014 annual incentive awards, determined as described in the CD&A.

(2) Represents performance share awards under the 2014 – 2016 Long-Term Incentive Program.

(3) Represents values of RSUs and other awards under long-term incentive programs and retention awards that, at year-end 2014, were unvested under applicable vesting schedules. Under these programs, upon termination in certain cases without cause or for good reason following a change of control, awards generally vest in full. Retention awards vest in full in such circumstances, and the payout value is reduced by any separation payments as described above. The values were calculated by multiplying the number of shares subject to awards by $53.52, the closing price of NU common shares on December 31, 2014, the last trading day of the year.

(4) Represents actuarial present value at year-end 2014 of amounts payable solely as a result of provisions in employment agreements (which are in addition to amounts payable under the pension program). For Messrs. May, Judge, McHale, Schweiger and Butler, pension benefits were calculated by adding three years of service (and a lump sum of this benefit value is payable to Messrs. May, Judge, Schweiger and Butler). Mr. Olivier's agreement provides for a lump sum payment of $5,304,563, offset by his pension program benefit value. Pension amounts shown in the table are present values at year-end 2014 of benefits payable upon termination as described with respect to the Pension Benefits Table above.

(5) Represents value of NU matching contributions under the deferred compensation program that were unvested under applicable vesting schedules (other amounts in this program represent previously vested NU matching contributions, where applicable, and earned compensation contributed by executives).

(6) Represents the cost to NU at year-end 2014 (estimated by our benefits consultants) of providing post-employment welfare benefits to Named Executive Officers beyond those benefits provided to non-executives upon involuntary termination. The amounts shown in the table for Messrs. May, Judge and Schweiger represent the value of three years continued welfare plan participation. The amounts shown in the table for Messrs. McHale and Butler represent (a) the value of three years employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) a payment to offset any taxes on the value of these benefits (gross-up), less (c) the value of one year retiree health coverage at retiree rates. The amounts reported in the table for Mr. Olivier represent (a) the value of two years employer contributions toward active health benefits, plus (b) a payment to offset any taxes on the value of these benefits (gross-up), less (c) the value of two years retiree health coverage at retiree rates.

(7) Represents cost to NU of reimbursing financial planning and tax preparation fees for three years.

(8) Represents payments made to offset costs to Messrs. McHale and Butler associated with certain excise taxes under Section 280G of the Internal Revenue Code. Executives may be subject to certain excise taxes under Section 280G if they receive payments and benefits related to a termination following a Change of Control that exceed specified Internal Revenue Service limits. Contractual agreements with the above executives provide for a grossed-up reimbursement of these excise taxes. The amounts in the table are based on the Section 280G excise tax rate of 20 percent, the statutory federal income tax withholding rate of 35 percent, the applicable state income tax rate, and the Medicare tax rate of 1.45 percent.

(9) Represents payments made under agreements or the SSP as consideration for agreement not to compete with NU following termination of employment equal to the sum of base salary plus relevant annual incentive award. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(10) Represents severance payments in addition to any non-compete agreement payments described in the prior note. For Messrs. May, Judge and Schweiger, this payment equals three-times the sum of base salary plus relevant annual incentive award (two-times the sum for Messrs. McHale and Butler, and one-time the sum for Mr. Olivier.) These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

NU

In addition to the information below under "Securities Authorized for Issuance Under Equity Compensation Plans," incorporated herein by reference is the information contained in the sections "Common Share Ownership of Certain Beneficial Owners" and "Common Share Ownership of Trustees and Management" of NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 13, 2015.

NSTAR ELECTRIC, PSNH and WMECO

Certain information required by this Item 12 has been omitted for NSTAR Electric, PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

CL&P

COMMON SHARE OWNERSHIP OF DIRECTORS AND MANAGEMENT

NU owns 100 percent of the outstanding common stock of CL&P. The table below shows the number of NU common shares beneficially owned as of February 19, 2015, by each of CL&P's directors and each Named Executive Officer of CL&P, as well as the number of NU common shares beneficially owned by all of CL&P's directors and executive officers as a group. The table also includes information about options, restricted share units and deferred shares credited to the accounts of CL&P's directors and executive officers under certain compensation and benefit plans. No equity securities of CL&P are owned by any of the Trustees, directors or executive officers of NU or CL&P. The address for the shareholders listed below is c/o Northeast Utilities, Prudential Center, 800 Boylston Street, Boston, Massachusetts 02199 for Messrs. May, Judge and Schweiger and c/o Northeast Utilities, 56 Prospect Street, Hartford, Connecticut 06103-2818 for Messrs. Butler, McHale and Olivier.

Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)(2)(3)	Percent of Class
Thomas J. May, Chairman of the Regulated Companies	1,644,902	*
Werner J. Schweiger, Chief Executive Officer, Director of the Regulated Companies	458,254	*
James J. Judge, Executive Vice President and Chief Financial Officer, Director of the Regulated Companies	308,597	*
Gregory B. Butler, Senior Vice President and General Counsel, Director of the Regulated Companies	159,446 (4)	*
David R. McHale, Executive Vice President and Chief Administrative Officer of NU and NUSCO	206,867 (5)	*
Leon J. Olivier, Executive Vice President-Enterprise Energy Strategy and Business Development of NU and NUSCO	205,483	*
All directors and executive officers as a group (10 persons)	3,275,512 (6)	1.0%

* Less than 1 percent of NU common shares outstanding.

(1) The persons named in the table have sole voting and investment power with respect to all shares beneficially owned by each of them, except as note below.

(2) Includes NU common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 19, 2015, as follows: Mr. May: 174,496 shares; and Mr. Schweiger: 171,872 shares.

Also includes restricted share units, deferred restricted share units and/or deferred shares, including dividend equivalents, as to which none of the individuals has voting or investment power, and phantom shares, representing employer matching contributions distributable only in cash, held by executive officers who participate in the Northeast Utilities Deferred Compensation Plan for Executives as follows; Mr. Butler: 84,837 shares; Mr. McHale: 115,827 shares; and Mr. Olivier: 102,118 shares. Also includes restricted share units and/or unvested and vested deferred shares, as to which none of the individuals has voting or investment power, held by executive officers who participate in the NSTAR 2007 Long Term Incentive Plan, as follows: Mr. Judge: 189,006 shares; Mr. May: 1,029,390 shares; and Mr. Schweiger: 206,140 shares.

Also includes unvested performance shares reported at target payouts, plus accumulated dividend equivalents, as to which none of the individuals has voting or investment power, as follows: Mr. Butler: 25,525 shares; Mr. Judge: 36,632 shares; Mr. May: 163,512 shares; Mr. McHale: 36,632 shares; Mr. Olivier: 38,501 shares; and Mr. Schweiger: 28,642 shares. Actual payouts of the performance shares, if any, at the conclusion of relevant performance periods will depend on the extent to which performance goals are satisfied.

(3) Includes NU common shares held as units in the 401(k) Plan invested in the NU Common Shares Fund over which the holder has sole voting and investment power (Mr. Butler: 4,862 shares; Mr. Judge: 22,598 shares; Mr. May: 66,197 shares; Mr. McHale: 7,422 shares; Mr. Olivier: 3,441 shares; and Mr. Schweiger: 8,719 shares).

(4) Includes 44,222 NU common shares owned jointly by Mr. Butler and his spouse with whom he shares voting and investment power.

(5) Includes 128 NU common shares held by Mr. McHale in the 401(k) Plan TRAESOP/PAYSOP account over which Mr. McHale has sole voting and investment power.

(6) Includes 346,368 NU common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 19, 2015, and 2,295,072 unissued NU common shares. See note 2.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth the number of NU common shares issuable under NU equity compensation plans, as well as their weighted exercise price, as of December 31, 2014, in accordance with the rules of the SEC:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	2,108,007	$26.69	3,888,995
Equity compensation plans not approved by security holders (d)	—	—	—
Total	2,108,007	$26.69	3,888,995

(a) Includes 351,616 common shares to be issued upon exercise of options, 1,380,747 common shares for distribution of restricted share units, and 375,644 performance shares issuable at target, all pursuant to the terms of our Incentive Plans.
(b) The weighted-average exercise price in Column (b) does not take into account restricted share units or performance shares, which have no exercise price.
(c) Includes 776,975 common shares issuable under our Employee Share Purchase Plan II.
(d) All of our current compensation plans under which equity securities of NU are authorized for issuance have been approved by shareholders of NU or the former shareholders of NSTAR.

Item 13. Certain Relationships and Related Transactions, and Director Independence

NU

Incorporated herein by reference is the information contained in the sections captioned "Trustee Independence" and "Certain Relationships and Related Transactions" of NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 13, 2015.

NSTAR ELECTRIC, PSNH and WMECO

Certain information required by this Item 13 has been omitted for NSTAR Electric, PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

CL&P

NU's Code of Ethics for Senior Financial Officers applies to the Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) of NU, CL&P and certain other NU subsidiaries. Under the Code, one's position as a Senior Financial Officer in the company may not be used to improperly benefit such officer or his or her family or friends. Under the Code, specific activities that may be considered conflicts of interest include, but are not limited to, directly or indirectly acquiring or retaining a significant financial interest in an organization that is a customer, vendor or competitor, or that seeks to do business with the company; serving, without proper safeguards, as an officer or director of, or working or rendering services for an organization that is a customer, vendor or competitor, or that seeks to do business with the company. Waivers of the provisions of the Code of Ethics for Trustees, executive officers or directors must be approved by NU's Board of Trustees. Any such waivers will be disclosed pursuant to legal requirements.

NU's Code of Business Conduct, which applies to all Trustees, directors, officers and employees of NU and its subsidiaries, including CL&P, contains a Conflict of Interest Policy that requires all such individuals to disclose any potential conflicts of interest. Such individuals are expected to discuss their particular situations with management to ensure appropriate steps are in place to avoid a conflict of interest. All disclosures must be reviewed and approved by management to ensure a particular situation does not adversely impact the individual's primary job and role.

NU's Related Party Transactions Policy is administered by the Corporate Governance Committee of NU's Board of Trustees. The Policy generally defines a "Related Party Transaction" as any transaction or series of transactions in which (i) NU or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any "Related Party" has a direct or indirect material interest. A "Related Party" is defined as any Trustee or nominee for Trustee, any executive officer, any shareholder owning more than 5 percent of NU's total outstanding shares, and any immediate family member of any such person. Management submits to the Corporate Governance Committee for consideration any Related Party Transaction into which NU or a subsidiary proposes to enter. The Corporate Governance Committee recommends to the NU Board of Trustees for approval only those transactions that are in NU's best interests. If management causes the company to enter into a Related Party Transaction prior to approval by the Corporate Governance Committee, the transaction will be subject to ratification by the NU Board of Trustees. If the NU Board of Trustees determines not to ratify the transaction, then management will make all reasonable efforts to cancel or annul such transaction.

The directors of CL&P are employees of CL&P and/or other subsidiaries of NU, and thus are not considered independent.

Item 14. Principal Accountant Fees and Services

NU

Incorporated herein by reference is the information contained in the section "Relationship with Independent Auditors" of NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 13, 2015.

CL&P, NSTAR ELECTRIC, PSNH and WMECO

Pre-Approval of Services Provided by Principal Auditors

None of CL&P, NSTAR Electric, PSNH or WMECO is subject to the audit committee requirements of the SEC, the national securities exchanges or the national securities associations. CL&P, NSTAR Electric, PSNH and WMECO obtain audit services from the independent auditor engaged by the Audit Committee of NU's Board of Trustees. NU's Audit Committee has established policies and procedures regarding the pre-approval of services provided by the principal auditors. Those policies and procedures delegate pre-approval of services to the NU Audit Committee Chair provided that such offices are held by Trustees who are "independent" within the meaning of the Sarbanes-Oxley Act of 2002 and that all such pre-approvals are presented to the NU Audit Committee at the next regularly scheduled meeting of the Committee.

The following relates to fees and services for the entire NU system, including NU, CL&P, NSTAR Electric, PSNH and WMECO.

Fees Billed by Principal Independent Registered Public Accounting Firm

The aggregate fees billed to NU and its subsidiaries by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, the Deloitte Entities), for the years ended December 31, 2014 and 2013 totaled $3,986,500 and $3,616,225, respectively. In addition, affiliates of Deloitte & Touche LLP as noted below provide other accounting services to NU. Fees were comprised of the following:

1. Audit Fees

The aggregate fees billed to NU and its subsidiaries by Deloitte & Touche LLP for audit services rendered for the years ended December 31, 2014 and 2013 totaled $3,775,000 and $3,493,925, respectively. The audit fees were incurred for audits of Northeast Utilities' annual consolidated financial statements and those of its subsidiaries, reviews of financial statements included in Northeast Utilities' Quarterly Reports on Form 10-Q and those of its subsidiaries, comfort letters, consents and other costs related to registration statements and financings. The fees also included audits of internal controls over financial reporting as of December 31, 2014 and 2013.

2. Audit Related Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2014 and 2013 totaled $175,000 and $100,000, respectively. The audit related fees were incurred for procedures performed in the ordinary course of business in support of certain regulatory filings.

3. Tax Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for tax services for the year ended December 31, 2013 totaled $20,800. Tax fees for 2013 related primarily to reviews of tax returns. There were no tax fees for the year ended December 31, 2014.

4. All Other Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for services other than the services described above for the years ended December 31, 2014 and 2013 totaled $36,500 and $1,500, respectively. The 2014 fees include $35,000 for an IT security assessment and both the 2014 and 2013 fees include $1,500 for a license for access to an accounting standards research tool.

NU's Audit Committee pre-approves all auditing services and permitted audit related or other services (including the fees and terms thereof) to be performed for us by our independent registered public accounting firm, subject to the de minimis exceptions for non-audit services described in Section 10A(i)(1)(B) of the Securities Exchange Act of 1934, which are approved by the Audit Committee prior to the completion of the audit. The Audit Committee may form and delegate its authority to subcommittees consisting of one or more members when appropriate, including the authority to grant pre-approvals of audit and permitted non-audit services, provided that decisions of such subcommittee to grant pre-approvals are presented to the full Audit Committee at its next scheduled meeting. During 2014, all services described above were pre-approved by the Audit Committee.

NU's Audit Committee has considered whether the provision by the Deloitte Entities of the non-audit services described above was allowed under Rule 2-01(c)(4) of Regulation S-X and was compatible with maintaining the independence of the registered public accountants and has concluded that the Deloitte Entities were and are independent of us in all respects.

PART IV
Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements:

The financial statements filed as part of this Annual Report on Form 10-K are set forth under Item 8, "Financial Statements and Supplementary Data."

2. Schedules

I.	Financial Information of Registrant: Northeast Utilities (Parent) Balance Sheets as of December 31, 2014 and 2013	S-1
	Northeast Utilities (Parent) Statements of Income for the Years Ended December 31, 2014, 2013 and 2012	S-2
	Northeast Utilities (Parent) Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012	S-2
	Northeast Utilities (Parent) Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012	S-3
II.	Valuation and Qualifying Accounts and Reserves for NU, CL&P, NSTAR Electric, PSNH and WMECO for 2014, 2013 and 2012	S-4

All other schedules of the companies for which inclusion is required in the applicable regulations of the SEC are permitted to be omitted under the related instructions or are not applicable, and therefore have been omitted.

3. Exhibit Index E-1

NORTHEAST UTILITIES

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHEAST UTILITIES

February 25, 2015

By: /s/ Jay S. Buth
Jay S. Buth
Vice President, Controller and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Gregory B. Butler, James J. Judge and Jay S. Buth and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Signature	Title	Date
/s/ Thomas J. May Thomas J. May	Chairman, President and Chief Executive Officer, and a Trustee (Principal Executive Officer)	February 25, 2015
/s/ James J. Judge James J Judge	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
/s/ Jay S. Buth Jay S. Buth	Vice President, Controller and Chief Accounting Officer	February 25, 2015
/s/ Richard H. Booth Richard H. Booth	Trustee	February 25, 2015
/s/ John S. Clarkeson John S. Clarkeson	Trustee	February 25, 2015
/s/ Cotton M. Cleveland Cotton M. Cleveland	Trustee	February 25, 2015
/s/ Sanford Cloud, Jr. Sanford Cloud, Jr.	Trustee	February 25, 2015
/s/ James S. DiStasio James S. DiStasio	Trustee	February 25, 2015
/s/ Francis A. Doyle Francis A. Doyle	Trustee	February 25, 2015

/s/ Charles K. Gifford Charles K. Gifford	Trustee	February 25, 2015
/s/ Paul A. La Camera Paul A. La Camera	Trustee	February 25, 2015
/s/ Kenneth R. Leibler Kenneth R. Leibler	Trustee	February 25, 2015
/s/ William C. Van Faasen William C. Van Faasen	Trustee	February 25, 2015
/s/ Frederica M. Williams Frederica M. Williams	Trustee	February 25, 2015
/s/ Dennis R. Wraase Dennis R. Wraase	Trustee	February 25, 2015

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY

February 25, 2015

By: /s/ Jay S. Buth
Jay S. Buth
Vice President, Controller and Chief Accounting Officer

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Signature	Title	Date
/s/ Thomas J. May Thomas J. May	Chairman and a Director (Principal Executive Officer)	February 25, 2015
/s/ Werner J. Schweiger Werner J. Schweiger	Chief Executive Officer and a Director	February 25, 2015
/s/ James J. Judge James J. Judge	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 25, 2015
/s/ Gregory B. Butler Gregory B. Butler	Senior Vice President and General Counsel and a Director	February 25, 2015
/s/ Jay S. Buth Jay S. Buth	Vice President, Controller and Chief Accounting Officer	February 25, 2015

NSTAR ELECTRIC COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NSTAR ELECTRIC COMPANY

February 25, 2015

By: /s/ Jay S. Buth
Jay S. Buth
Vice President, Controller and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

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/s/ Thomas J. May Thomas J. May	Chairman and a Director (Principal Executive Officer)	February 25, 2015
/s/ Werner J. Schweiger Werner J. Schweiger	Chief Executive Officer and a Director	February 25, 2015
/s/ James J. Judge James J. Judge	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 25, 2015
/s/ Gregory B. Butler Gregory B. Butler	Senior Vice President and General Counsel and a Director	February 25, 2015
/s/ Jay S. Buth Jay S. Buth	Vice President, Controller and Chief Accounting Officer	February 25, 2015

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

February 25, 2015

By: /s/ Jay S. Buth
Jay S. Buth
Vice President, Controller and Chief Accounting Officer

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Signature	Title	Date
/s/ Thomas J. May Thomas J. May	Chairman and a Director (Principal Executive Officer)	February 25, 2015
/s/ Werner J. Schweiger Werner J. Schweiger	Chief Executive Officer and a Director	February 25, 2015
/s/ James J. Judge James J. Judge	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 25, 2015
/s/ Gregory B. Butler Gregory B. Butler	Senior Vice President and General Counsel and a Director	February 25, 2015
/s/ Jay S. Buth Jay S. Buth	Vice President, Controller and Chief Accounting Officer	February 25, 2015

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY

February 25, 2015

By: /s/ Jay S. Buth
Jay S. Buth
Vice President, Controller and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

POWER OF ATTORNEY

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Signature	Title	Date
/s/ Thomas J. May Thomas J. May	Chairman and a Director (Principal Executive Officer)	February 25, 2015
/s/ Werner J. Schweiger Werner J. Schweiger	Chief Executive Officer and a Director	February 25, 2015
/s/ James J. Judge James J. Judge	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 25, 2015
/s/ Gregory B. Butler Gregory B. Butler	Senior Vice President and General Counsel and a Director	February 25, 2015
/s/ Jay S. Buth Jay S. Buth	Vice President, Controller and Chief Accounting Officer	February 25, 2015

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AS OF DECEMBER 31, 2014 AND 2013
(Thousands of Dollars)

	2014	2013
ASSETS		
Current Assets:		
Cash	$ 138	$ 35
Accounts Receivable from Subsidiaries	6,725	95,513
Notes Receivable from Subsidiaries	741,150	871,050
Prepayments and Other Current Assets	41,366	59,905
Total Current Assets	789,379	1,026,503
Deferred Debits and Other Assets:		
Investments in Subsidiary Companies, at Equity	8,387,976	7,733,051
Notes Receivable from Subsidiaries	106,300	62,500
Accumulated Deferred Income Taxes	177,908	205,779
Goodwill	3,231,811	3,231,811
Other Long-Term Assets	33,552	22,099
Total Deferred Debits and Other Assets	11,937,547	11,255,240
Total Assets	$ 12,726,926	$ 12,281,743
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable	$ 654,825	$ 1,014,500
Long-Term Debt - Current Portion	28,883	31,696
Accounts Payable	141	441
Accounts Payable to Subsidiaries	150,268	144,026
Other	71,778	59,559
Total Current Liabilities	905,895	1,250,222
Deferred Credits and Other Liabilities:		
Other	125,608	122,226
Total Deferred Credits and Other Liabilities	125,608	122,226
Capitalization:		
Long-Term Debt	1,718,608	1,297,767
Equity:		
Common Shareholders' Equity:		
Common Shares	1,666,796	1,665,351
Capital Surplus, Paid in	6,235,834	6,192,765
Retained Earnings	2,448,661	2,125,980
Accumulated Other Comprehensive Loss	(74,009)	(46,031)
Treasury Stock	(300,467)	(326,537)
Common Shareholders' Equity	9,976,815	9,611,528
Total Capitalization	11,695,423	10,909,295
Total Liabilities and Capitalization	$ 12,726,926	$ 12,281,743

See the *Combined Notes to Consolidated Financial Statements* in this Annual Report on Form 10-K for a description of significant accounting matters related to NU parent, including NU common shares information as described in Note 16, "Common Shares," material obligations and guarantees as described in Note 11, "Commitments and Contingencies," and debt agreements as described in Note 7, "Short-Term Debt," and Note 8, "Long-Term Debt."

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012
(Thousands of Dollars, Except Share Information)

	2014	2013	2012 [1]
Operating Revenues	$ -	$ 8	$ 2
Operating Expenses:			
Other	29,598	12,766	80,719
Operating Loss	(29,598)	(12,758)	(80,717)
Interest Expense	33,168	31,639	36,325
Other Income, Net:			
Equity in Earnings of Subsidiaries	848,435	785,650	579,221
Other, Net	1,830	5,062	6,080
Other Income, Net	850,265	790,712	585,301
Income Before Income Tax Benefit	787,499	746,315	468,259
Income Tax Benefit	(32,047)	(39,692)	(57,789)
Net Income	819,546	786,007	526,048
Net Income Attributable to Noncontrolling Interest	-	-	103
Net Income Attributable to Controlling Interest	$ 819,546	$ 786,007	$ 525,945
Basic Earnings per Common Share	$ 2.59	$ 2.49	$ 1.90
Diluted Earnings per Common Share	$ 2.58	$ 2.49	$ 1.89
Weighted Average Common Shares Outstanding:			
Basic	316,136,748	315,311,387	277,209,819
Diluted	317,417,414	316,211,160	277,993,631

STATEMENTS OF COMPREHENSIVE INCOME

	2014	2013	2012
Net Income	$ 819,546	$ 786,007	$ 526,048
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	2,037	2,049	1,971
Changes in Unrealized Gains/(Losses) on Other Securities	315	(940)	217
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	(30,330)	25,714	(4,356)
Other Comprehensive Income/(Loss), Net of Tax	(27,978)	26,823	(2,168)
Comprehensive Income Attributable to Noncontrolling Interest	-	-	(103)
Comprehensive Income Attributable to Controlling Interest	$ 791,568	$ 812,830	$ 523,777

[1] On April 10, 2012, NU acquired NSTAR and its subsidiaries. The financial information includes NSTAR and its subsidiaries' results of operations beginning April 10, 2012. See Note 21, "Merger of NU and NSTAR," for further information regarding the merger.

See the Combined Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a description of significant accounting matters related to NU parent, including NU common shares information as described in Note 16, "Common Shares," material obligations and guarantees as described in Note 11, "Commitments and Contingencies," and debt agreements as described in Note 7, "Short-Term Debt," and Note 8, "Long-Term Debt."

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 and 2012
(Thousands of Dollars)

	2014	2013	2012 [1]
Operating Activities:			
Net Income	$ 819,546	$ 786,007	$ 526,048
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:			
Equity in Earnings of Subsidiaries	(848,435)	(785,650)	(579,221)
Cash Dividends Received from Subsidiaries	609,800	407,837	374,584
Deferred Income Taxes	7,956	15,159	(15,350)
Other	9,409	29,169	(3,755)
Changes in Current Assets and Liabilities:			
Accounts Receivables from Subsidiaries	88,800	14,704	(18,321)
Taxes Receivable/Accrued, Net	23,178	13,295	(16,872)
Accounts Payable, Including Affiliate Payables	5,942	(7,058)	48,332
Other Current Assets and Liabilities, Net	14,484	(1,411)	60,182
Net Cash Flows Provided by Operating Activities	730,680	472,052	375,627
Investing Activities:			
Capital Contributions to Subsidiaries	(437,553)	(65,400)	(81,431)
Return of Investment in Subsidiaries	-	-	8,207
Decrease in Money Pool Lending	-	-	2,200
Decrease/(Increase) in Notes Receivable from Subsidiaries	86,100	5,475	(704,475)
Other Investing Activities	-	(1,862)	(608)
Net Cash Flows Used in Investing Activities	(351,453)	(61,787)	(776,107)
Financing Activities:			
Cash Dividends on Common Shares	(475,227)	(462,741)	(375,047)
Issuance of Long-Term Debt	-	750,000	300,000
Retirement of Long-Term Debt	-	(550,000)	(263,000)
Increase/(Decrease) in Short-Term Debt	86,575	(135,500)	733,500
Other Financing Activities	9,528	(12,418)	5,394
Net Cash Flows (Used in)/Provided by Financing Activities	(379,124)	(410,659)	400,847
Net Increase/(Decrease) in Cash	103	(394)	367
Cash - Beginning of Year	35	429	62
Cash - End of Year	$ 138	$ 35	$ 429
Supplemental Cash Flow Information:			
Cash Paid/(Received) During the Year for:			
Interest	$ 36,208	$ 33,822	$ 50,144
Income Taxes	$ (86,804)	$ (30,603)	$ (27,126)

[1] On April 10, 2012, NU acquired NSTAR and its subsidiaries. The financial information includes NSTAR and its subsidiaries' cash flows beginning April 10, 2012. See Note 21, "Merger of NU and NSTAR," for further information regarding the merger.

See the Combined Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a description of significant accounting matters related to NU parent, including NU common shares information as described in Note 16, "Common Shares," material obligations and guarantees as described in Note 11, "Commitments and Contingencies," and debt agreements as described in Note 7, "Short-Term Debt," and Note 8, "Long-Term Debt."

SCHEDULE II
NORTHEAST UTILITIES AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012
(Thousands of Dollars)

Column A	Column B	Column C			Column D	Column E
		Additions				
		(1)	(2)	(3)		
Description:	Balance as of Beginning of Year	Charged to Costs and Expenses	Charged to Other Accounts - Describe (a)	Impact Related to Merger With NSTAR	Deductions - Describe (b)	Balance as of End of Year
NU:						
Reserves Deducted from Assets -						
Reserves for Uncollectible Accounts:						
2014	$ 171,251	$ 55,657	$ 51,227	$ -	$ 102,818	$ 175,317
2013	165,549	55,465	37,744	-	87,507	171,251
2012	115,689	36,275	34,761	59,286	80,462	165,549
CL&P:						
Reserves Deducted from Assets -						
Reserves for Uncollectible Accounts:						
2014	$ 81,995	$ 6,598	$ 39,706	$ -	$ 44,012	$ 84,287
2013	77,571	3,947	27,258	-	26,781	81,995
2012	83,475	2,080	27,084	-	35,068	77,571
NSTAR Electric:						
Reserves Deducted from Assets -						
Reserves for Uncollectible Accounts:						
2014	$ 41,679	$ 24,740	$ 627	$ -	$ 26,376	$ 40,670
2013	44,115	28,108	-	-	30,544	41,679
2012	27,118	40,301	-	-	23,304	44,115
PSNH:						
Reserves Deducted from Assets -						
Reserves for Uncollectible Accounts:						
2014	$ 7,364	$ 6,815	$ 797	$ -	$ 7,313	$ 7,663
2013	6,760	6,608	779	-	6,783	7,364
2012	7,190	6,457	2,481	-	9,368	6,760
WMECO:						
Reserves Deducted from Assets -						
Reserves for Uncollectible Accounts:						
2014	$ 9,984	$ 2,415	$ 3,608	$ -	$ 6,127	$ 9,880
2013	8,501	2,580	4,299	-	5,396	9,984
2012	10,018	2,294	2,428	-	6,239	8,501

(a) Amounts relate to uncollectible accounts receivables reserved for that are not charged to bad debt expense. The PURA allows CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivables outstanding for greater than 90 days. The DPU allows WMECO to recover in rates amounts associated with certain uncollectible hardship accounts receivables.

(b) Amounts written off, net of recoveries.

EXHIBIT INDEX

Each document described below is incorporated by reference by the registrant(s) listed to the files identified, unless designated with a (*), which exhibits are filed herewith. Management contracts and compensation plans or arrangements are designated with a (+).

Exhibit Number Description

3. Articles of Incorporation and By-Laws

(A) Northeast Utilities

3.1 Declaration of Trust of NU, as amended through May 10, 2005 (Exhibit A.1, NU Form U-1 filed June 23, 2005, File No. 70-10315)

(B) The Connecticut Light and Power Company

3.1 Certificate of Incorporation of CL&P, restated to March 22, 1994 (Exhibit 3.2.1, 1993 CL&P Form 10-K, File No. 000-00404)

3.1.1 Certificate of Amendment to Certificate of Incorporation of CL&P, dated December 26, 1996 (Exhibit 3.2.2, 1996 CL&P Form 10-K filed March 25, 1997, File No. 001-11419)

3.1.2 Certificate of Amendment to Certificate of Incorporation of CL&P, dated April 27, 1998 (Exhibit 3.2.3, 1998 CL&P Form 10-K filed March 23, 1999, File No. 000-00404)

3.1.3 Amended and Restated Certificate of Incorporation of CL&P, dated effective January 3, 2012 (Exhibit 3(i), CL&P Current Report on Form 8-K filed January 9, 2012, File No. 000-00404)

3.2 By-laws of CL&P, as amended and restated effective September 29, 2014 (Exhibit 3.1, CL&P Current Report on Form 8-K filed October 2, 2014, File No. 000-00404)

(C) NSTAR Electric Company

3.1 Restated Articles of Organization of NSTAR Electric Company, fka Boston Edison Company (Exhibit 3.1, NSTAR Electric Form 10-Q for the Quarter Ended June 30, 1994 filed August 12, 1994, File No. 001-02301)

3.2 Bylaws of NSTAR Electric Company, as amended and restated effective September 29, 2014 (Exhibit 3.1, NSTAR Electric Current Report on Form 8-K filed October 2, 2014, File No. 000-02301)

(D) Public Service Company of New Hampshire

3.1 Articles of Incorporation, as amended to May 16, 1991 (Exhibit 3.3.1, 1993 PSNH Form 10-K filed March 25, 1994, File No. 001-06392)

3.2 By-laws of PSNH, as in effect June 27, 2008 (Exhibit 3, PSNH Form 10-Q for the Quarter Ended June 30, 2008 filed August 7, 2008, File No. 001-06392)

(E) Western Massachusetts Electric Company

3.1 Articles of Organization of WMECO, restated to February 23, 1995 (Exhibit 3.4.1, 1994 WMECO Form 10-K filed March 27, 1995, File No. 001-07624)

3.2 By-laws of WMECO, as amended to April 1, 1999 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 1999 filed August 13, 1999, File No. 000-07624)

3.2.1 By-laws of WMECO, as further amended to May 1, 2000 (Exhibit 3.1, WMECO Form 10-Q for the Quarter Ended June 30, 2000 filed August 11, 2000, File No. 000-07624)

4. Instruments defining the rights of security holders, including indentures

(A) Northeast Utilities

4.1 Indenture between NU and The Bank of New York as Trustee dated as of April 1, 2002 (Exhibit A-3, NU 35-CERT filed April 16, 2002, File No. 070-09535)

4.1.1 Fifth Supplemental Indenture between NU and The Bank of New York Trust Company N.A., as Trustee, dated as of May 1, 2013, relating to $300 million of Senior Notes, Series E, due 2018 and $400 million of Senior Notes, Series F, due 2023 (Exhibit 4.1, NU Current Report on Form 8-K filed May 16, 2013, File No. 001-05324)

4.1.2 Sixth Supplemental Indenture between NU and The Bank of New York Trust Company N.A., as Trustee, dated as of January 1, 2015, relating to $150 million of Senior Notes, Series G, due 2018 and $300 million of Senior Notes, Series H, due 2025 (Exhibit 4.1, NU Current Report on Form 8-K filed January 21, 2015, File No. 001-05324)

4.2 Indenture dated as of January 12, 2000, between NU, as successor to NSTAR LLC, as successor to NSTAR, and Bank One Trust Company N.A. (Exhibit 4.1 to NSTAR Registration Statement on Form S-3, File No. 333-94735)

4.2.1 Form of 4.50% Debenture Due 2019 (Exhibit 99.2, NSTAR Form 8-K filed November 16, 2009, File No. 001-14768)

4.3 Credit Agreement, dated July 25, 2012, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, NU Form 10-Q for the Quarter Ended September 30, 2012, filed November 7, 2012, File No. 001-05324)

4.3.1 First Amendment to Credit Agreement, dated September 6, 2013, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, NU Current Report on Form 8-K filed September 12, 2013, File No. 001-05324)

(B) The Connecticut Light and Power Company

4.1 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921 (Composite including all twenty-four amendments to May 1, 1967) (Exhibit 4.1.1, 1989 NU Form 10-K, File No. 001-05324)

4.1.1 Series D Supplemental Indentures to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of October 1, 1994 (Exhibit 4.2.16, 1994 CL&P Form 10-K filed March 27, 1995, File No. 001-11419)

4.1.2 Series A Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee, dated as of September 1, 2004 (Exhibit 99.2, CL&P Current Report on Form 8-K filed September 22, 2004, File No. 000-00404)

4.1.3 Series B Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2004 (Exhibit 99.5, CL&P Current Report on Form 8-K filed September 22, 2004, File No. 000-00404)

4.2 Composite Indenture of Mortgage and Deed of Trust between CL&P and Deutsche Bank Trust Company Americas f/k/a Bankers Trust Company, dated as of May 1, 1921, as amended and supplemented by seventy-three supplemental mortgages to and including Supplemental Mortgage dated as of April 1, 2005 (Exhibit 99.5, CL&P Current Report on Form 8-K filed April 13, 2005, File No. 000-00404)

4.2.1 Supplemental Indenture (2005 Series A Bonds and 2005 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of April 1, 2005 (Exhibit 99.2, CL&P Current Report on Form 8-K filed April 13, 2005, File No. 000-00404)

4.2.2 Supplemental Indenture (2007 Series A Bonds and 2007 Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of March 1, 2007 (Exhibit 99.2, CL&P Current Report on Form 8-K filed March 29, 2007, File No. 000-00404)

4.2.3 Supplemental Indenture (2007 Series C Bonds and 2007 Series D Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2007 (Exhibit 4, CL&P Current Report on Form 8-K filed September 19, 2007, File No. 000-00404)

4.2.4 Supplemental Indenture (2008 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of May 1, 2008 (Exhibit 4, CL&P Current Report on Form 8-K filed May 29, 2008, File No. 000-00404)

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4.2.5 Supplemental Indenture (2009 Series A Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of February 1, 2009 (Exhibit 4, CL&P Current Report on Form 8-K filed February 19, 2009, File No. 000-00404)

4.2.6 Supplemental Indenture (2011 Series A and Series B Bonds) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of October 1, 2011 (Exhibit 4.1, CL&P Current Report on Form 8-K filed October 28, 2011, File No. 000-00404)

4.2.7 Supplemental Indenture (2013 Series A Bond) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of January 1, 2013 (Exhibit 4.1, CL&P Current Report on Form 8-K filed January 22, 2013, File No. 000-00404)

4.2.8 Supplemental Indenture (2014 Series A Bond) between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of April 1, 2014 (Exhibit 4.1, CL&P Current Report on Form 8-K filed April 29, 2014, File No. 000-00404)

4.3 Amended and Restated Loan Agreement between Connecticut Development Authority and CL&P dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Pollution Control Revenue Bond - 1996A Series) (Exhibit 4.2.24, 1996 CL&P Form 10-K filed March 25, 1997, File No. 001-11419)

4.3.1 First Amendment to Amended and Restated Loan Agreement, between the Connecticut Development Authority and CL&P dated as of October 1, 2008 (Pollution Control Revenue Bond-1996A Series) (Exhibit 10.1, CL&P Form 10-Q for the Quarter Ended September 30, 2008, filed November 10, 2008, File No. 000-00404)

4.4 Amended and Restated Indenture of Trust between Connecticut Development Authority and Fleet National Bank, the Trustee dated as of May 1, 1996 and Amended and Restated as of January 1, 1997 (Pollution Control Revenue Bond-1996A Series) (Exhibit 4.2.24.1, 1996 CL&P Form 10-K, filed March 25, 1997, File No. 001-11419)

4.4.1 First Amendment to Amended and Restated Indenture of Trust between Connecticut Development Authority and U.S. Bank National Association, as Trustee dated as of October 1, 2008 (Exhibit 10.2 CL&P Form 10-Q for the Quarter Ended September 30, 2008, filed November 10, 2008, File No. 000-00404)

4.5 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Refunding Bonds – 2011A Series) dated as of October 1, 2011 (Exhibit 1.1, CL&P Current Report on Form 8-K filed October 28, 2011, File No. 000-00404)

4.6 Credit Agreement, dated July 25, 2012, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, CL&P Form 10-Q for the Quarter Ended September 30, 2012, filed November 7, 2012, File No. 001-05324)

4.6.1 First Amendment to Credit Agreement, dated September 6, 2013, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, CL&P Current Report on Form 8-K filed on September 12, 2013, File No. 001-05324)

(C) NSTAR Electric Company

4.1 Indenture between Boston Edison Company and the Bank of New York (as successor to Bank of Montreal Trust Company) (Exhibit 4.1, NSTAR Electric Form 10-Q for the Quarter Ended September 30, 1988, File No. 001-02301)

4.1.1 A Form of 5.75% Debenture Due March 15, 2036 (Exhibit 99.2, Boston Edison Company Current Report on Form 8-K filed March 17, 2006, File No. 001-02301)

4.1.2 A Form of 5.625% Debenture Due November 15, 2017 (Exhibit 99.2, NSTAR Electric Company Current Report on Form 8-K filed November 20, 2007 and filed February 17, 2009, File No. 001-02301)

4.1.3 A Form of 5.50% Debenture Due March 15, 2040 (Exhibit 99.2, NSTAR Electric Company Current Report on Form 8-K filed March 15, 2010, File No. 001-02301)

4.1.4 A Form of 2.375% Debenture Due 2022 (Exhibit 4, NSTAR Electric Company Current Report on Form 8-K filed October 18, 2012, File No. 001-02301)

4.1.5 A Form of Floating Rate Debenture Due 2016 (Exhibit 4, NSTAR Electric Company Current Report on Form 8-K filed May 22, 2013, File No. 001-02301)

4.1.6 A Form of 4.40% Debenture Due 2044 (Exhibit 4, NSTAR Electric Company Current Report on Form 8-K filed March 13, 2014, File No. 001-02301)

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4.2 Credit Agreement, dated July 25, 2012, by and between NSTAR Electric and the Banks named therein, pursuant to which Barclays Bank PLC serves as Administrative Agent and Swing Line Lender (Exhibit 4.1, NSTAR Electric Company Form 10-Q for the Quarter Ended September 30, 2012, filed November 7, 2012, File No. 001-05324)

4.2.1 First Amendment to Credit Agreement, dated September 6, 2013, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, NSTAR Electric Company Current Report on Form 8-K filed on September 12, 2013, File No. 001-05324)

(D) Public Service Company of New Hampshire

4.1 First Mortgage Indenture between PSNH and First Fidelity Bank, National Association, New Jersey, now First Union National Bank, Trustee, dated as of August 15, 1978 (Composite including all amendments effective June 1, 2011) (included as Exhibit C to the Eighteenth Supplemental Indenture filed as Exhibit 4.1 to PSNH Current Report on Form 8-K filed June 2, 2011, File No. 001-06392)

4.1.1 Fourteenth Supplemental Indenture between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee dated as of October 1, 2005 (Exhibit 99.2, PSNH Current Report on Form 8-K filed October 6, 2005, File No. 001-06392)

4.1.2 Fifteenth Supplemental Indenture between PSNH and Wachovia Bank, National Association successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee dated as of September 1, 2007 (Exhibit 4.1, PSNH Current Report on Form 8-K filed September 25, 2007, File No. 001-06392)

4.1.3 Sixteenth Supplemental Indenture between PSNH and U.S. Bank National Association, Trustee, dated as of May 1, 2008 (Exhibit 4.1 to PSNH Current Report on Form 8-K filed May 29, 2008 (File No.001-06392)

4.1.4 Seventeenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of December 1, 2009 (Exhibit 4.1, PSNH Current Report on Form 8-K filed December 15, 2009 (File No. 001-06392)

4.1.5 Eighteenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of May 1, 2011 (Exhibit 4.1, PSNH Current Report on Form 8-K filed June 2, 2011 (File No. 001-06392)

4.1.6 Nineteenth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of September 1, 2011 (Exhibit 4.1, PSNH Current Report on Form 8-K filed September 16, 2011 (File No. 001-06392)

4.1.7 Twentieth Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of November 1, 2013 (Exhibit 4.1, PSNH Current Report on Form 8-K filed November 20, 2013 (File No. 001-06392)

4.1.8 Twenty-first Supplemental Indenture, between PSNH and U.S. Bank National Association, as Trustee dated as of October 1, 2014 (Exhibit 4.1, PSNH Current Report on Form 8-K filed October 17, 2014 (File No. 001-06392)

4.2 Series A Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001 (Exhibit 4.3.4, 2001 NU Form 10-K filed March 22, 2002, File No. 001-05324)

4.3 Credit Agreement, dated July 25, 2012, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, PSNH Form 10-Q for the Quarter Ended September 30, 2012, filed November 7, 2012, File No. 001-05324)

4.3.1 First Amendment to Credit Agreement, dated September 6, 2013, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, PSNH Current Report on Form 8-K filed on September 12, 2013, File No. 001-05324)

(E) Western Massachusetts Electric Company

4.1 Loan Agreement between Connecticut Development Authority and WMECO, (Pollution Control Revenue Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993 (Exhibit 4.4.13, 1993 WMECO Form 10-K filed March 25,1994, File No. 000-07624)

4.2 Indenture between WMECO and The Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.2, WMECO Current Report on Form 8-K filed October 8, 2003, File No. 000-07624)

4.2.1 Second Supplemental Indenture between WMECO and The Bank of New York, as Trustee dated as of September 1, 2004 (Exhibit 4.1, WMECO Current Report on Form 8-K filed September 27, 2004, File No. 000-07624)

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Public Service Company of New Hampshire

4.2.2 Third Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2005 (Exhibit 4.1, WMECO Current Report on Form 8-K filed August 12, 2005, File No. 000-07624)

4.2.3 Fourth Supplemental Indenture between WMECO and The Bank of New York Trust, as Trustee, dated as of August 1, 2007 (Exhibit 4.1, WMECO Current Report on Form 8-K filed August 20, 2007, File No. 000-07624)

4.2.4 Fifth Supplemental Indenture between WMECO and The Bank of New York Trust Company, N.A., as Trustee, dated as of March 1, 2010 (Exhibit 4.1, WMECO Current Report on Form 8-K filed March 10, 2010, File No. 000-07624)

4.2.5 Sixth Supplemental Indenture between WMECO and The Bank of New York Trust Company, N.A., as Trustee, dated as of September 15, 2011 (Exhibit 4.1, WMECO Current Report on Form 8-K filed September 19, 2011, File No. 000-07624)

4.2.6 Seventh Supplemental Indenture between WMECO and The Bank of New York Trust Company, N.A., as Trustee, dated as of November 1, 2013 (Exhibit 4.1, WMECO Current Report on Form 8-K filed November 21, 2013, File No. 000-07624)

4.3 Credit Agreement, dated July 25, 2012, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent (Exhibit 4.1, WMECO Form 10-Q for the Quarter Ended September 30, 2012, filed November 7, 2012, File No. 001-05324)

4.3.1 First Amendment to Credit Agreement, dated September 6, 2013, by and among NU, CL&P, NSTAR Gas, NSTAR LLC, PSNH, WMECO, Yankee Gas Services Company and the Banks named therein, pursuant to which Bank of America, N.A. serves as Administrative Agent Exhibit 4.1, WMECO Current Report on Form 8-K filed on September 12, 2013, File No. 001-05324)

10. Material Contracts

(A) NU

10.1 Lease between The Rocky River Realty Company and Northeast Utilities Service Company dated as of April 14, 1992 with respect to the Berlin, Connecticut headquarters (Exhibit 10.29.1, 1992 NU Form 10-K, File No. 001-05324)

10.2 Amended and Restated Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and the Bank of New York Mellon Trust company, N.A. formerly Connecticut National Bank, as Trustee, dated July 1, 1989, (Composite including all amendments effective January 1, 2014) (included as Exhibit B to the Eleventh Supplemental Indenture filed as Exhibit 10, NU Form 10-Q for the Quarter Ended March 31, 2014 filed May 2, 2014, File No. 001-05324)

10.2.1 First Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Connecticut National Bank, as Trustee, dated April 1, 1992 (Yankee Energy System, Inc. Registration Statement on Form S-3, dated October 2, 1992, File No. 33-52750

10.2.2 Sixth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) dated January 1, 2004 (Exhibit 10.5.6, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.2.3 Seventh Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) dated November 1, 2004 (Exhibit 10.5.7, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.2.4 Eighth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly the Connecticut National Bank) dated July 1, 2005 (Exhibit 10.5.8, NU Form 10-Q for the Quarter Ended June 30, 2005 filed August 8, 2005, File No. 001-05324)

10.2.5 Ninth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as Trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank) dated as of October 1, 2008 (Exhibit 10-1, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

10.2.6 Tenth Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as Trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank), dated as of April 1, 2010 (Exhibit 10, NU Form 10-Q for the Quarter Ended March 31, 2010 filed May 7, 2010, File No. 001-05324)

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10.2.7 Eleventh Supplemental Indenture of Mortgage and Deed of Trust between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as Trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank), dated as of January 1, 2014 (Exhibit 10, NU Form 10-Q for the Quarter Ended March 31, 2014 filed May 2, 2014, File No. 001-05324)

* +10.3 Northeast Utilities Board of Trustees' Compensation Arrangement Summary

+10.4 Amended and Restated Northeast Utilities Deferred Compensation Plan for Trustees, effective January 1, 2009 (Exhibit 10.6, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

10.5 Composite Transmission Service Agreement, by and between Northern Pass Transmission LLC, as Owner and H.Q. Hydro Renewable Energy, Inc., as Purchaser dated October 4, 2010 and effective February 14, 2014

(B) NU, CL&P, PSNH and WMECO

10.1 Amended and Restated Form of Service Contract between each of NU, CL&P and WMECO and Northeast Utilities Service Company (NUSCO) dated as of January 1, 2014. (Exhibit 10.1, NU Form 10-K filed on February 25, 2014, File No. 001-05324)

10.2 Agreements among New England Utilities with respect to the Hydro-Quebec interconnection projects (Exhibits 10(u) and 10(v); 10(w), 10(x), and 10(y), 1990 and 1988, respectively, Form 10-K of New England Electric System, File No. 001-03446)

10.3 Transmission Operating Agreement between the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc. dated as of February 1, 2005 (Exhibit 10.29, 2004 NU Form 10-K filed March 17, 2005, File No. 001-05324)

10.3.1 Rate Design and Funds Disbursement Agreement among the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc., effective June 30, 2006 (Exhibit 10.22.1, 2006 NU Form 10-K filed March 1, 2007, File No. 001-05324)

10.4 Northeast Utilities Service Company Transmission and Ancillary Service Wholesale Revenue Allocation Methodology among The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Holyoke Water Power Company and Holyoke Power and Electric Company Trustee dated as of January 1, 2008 (Exhibit 10.1, NU Form 10-Q for the Quarter Ended March 31, 2008 filed May 9, 2008, File No. 001-05324)

+10.5 Amended and Restated Employment Agreement with Gregory B. Butler, effective January 1, 2009 (Exhibit 10.7, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.6 Amended and Restated Employment Agreement with David R. McHale, effective January 1, 2009 (Exhibit 10.8, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.7 Amended and Restated Memorandum Agreement between Northeast Utilities and Leon J. Olivier effective January 1, 2009 (Exhibit 10.9, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.8 Amended and Restated Incentive Plan Effective January 1, 2009 (Exhibit 10.3, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.9 Amended and Restated Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Company effective January 1, 2009 (Exhibit 10.5, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.10 Trust under Supplemental Executive Retirement Plan dated May 2, 1994 (Exhibit 10.33, 2002 NU Form 10-K filed March 21, 2003, File No. 001-05324)

+10.10.1 First Amendment to Trust Under Supplemental Executive Retirement Plan, effective as of December 10, 2002 (Exhibit 10 (B) 10.19.1, 2003 NU Form 10-K filed March 12, 2004, File No. 001-05324)

+10.10.2 Second Amendment to Trust Under Supplemental Executive Retirement Plan , effective as of November 12, 2008 (Exhibit 10.12.2, 2008 NU Form 10-K filed February 27, 2009, File No. 001-05324)

+10.11 Special Severance Program for Officers of NU System Companies as of January 1, 2009 (Exhibit 10.2, NU Form 10-Q for the Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.12 Amended and Restated Northeast Utilities Deferred Compensation Plan for Executives effective as of January 1, 2009 (Exhibit 10.4 NU Form 10-Q for Quarter Ended September 30, 2008 filed November 10, 2008, File No. 001-05324)

+10.13 Northeast Utilities Retention Agreement (Exhibit 10.1, NU Registration Statement on Form S-4, filed November 22, 2010, File No. 333-170754)

10.14 Northeast Utilities System's Third Amended and Restated Tax Allocation Agreement dated as of April 10, 2012. (Exhibit 10.1 NU Form 10-Q for Quarter Ended June 30, 2012 filed August 7, 2012, File No. 001-05324)

(C) NU and CL&P

10.1 CL&P Agreement Re: Connecticut NEEWS Projects by and between CL&P and The United Illuminating Company dated July 14, 2010 (Exhibit 10, CL&P Form 10-Q for the Quarter Ended June 30, 2010 filed August 6, 2010, File No. 000-00404)

(D) NU and NSTAR Electric

10.1 NSTAR Electric Company Restructuring Settlement Agreement dated July 1997, (Exhibit 10.12, Boston Edison 1997 Form 10-K filed March 30, 1998, File No. 001-02301)

10.2 Amended and Restated Power Purchase Agreement (NEA A PPA), dated August 19, 2004, by and between Boston Edison and Northeast Energy Associates L.P. (Exhibit 10.18, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.3 Amended and Restated Power Purchase Agreement (NEA B PPA), dated August 19, 2004, by and between ComElectric and Northeast Energy Associates L. P. (Exhibit 10.19, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.4 Amended and Restated Power Purchase Agreement (CECO 1 PPA), dated August 19, 2004 by and between ComElectric and Northeast Energy Associates L. P. (Exhibit 10.20, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.5 Amended and Restated Power Purchase Agreement (CECO 2 PPA), dated August 19, 2004 by and between ComElectric and Northeast Energy Associates L. P. (Exhibit 10.21, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.6 The Bellingham Execution Agreement, dated August 19, 2004 between Boston Edison, ComElectric and Northeast Energy Associates L. P. (Exhibit 10.22, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.7 Second Restated NEPOOL Agreement among NSTAR Electric and various other electric utilities operating in New England, dated August 16, 2004 (Exhibit 10.2.1.1, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.8 Transmission Operating Agreement among NSTAR Electric and various electric transmission providers in New England and ISO New England Inc., dated February 1, 2005 (Exhibit 10.2.1.2, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.9 Market Participants Service Agreement among NSTAR Electric and various other electric utilities operating in New England, NEPOOL and ISO New England Inc., dated February 1, 2005 (Exhibit 10.2.1.3, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.10 Rate Design and Funds Disbursement Agreement among NSTAR Electric and various other electric transmission providers in New England, dated February 1, 2005 (Exhibit 10.2.1.4, 2005 NSTAR Form 10-K filed February 21, 2006, File No. 001-14768)

10.11 Participants Agreement among NSTAR Electric, various electric utilities operating in New England, NEPOOL and ISO-New England, Inc., dated February 1, 2005 (Exhibit 10.2.1.4, 2006 NSTAR Form 10-K filed February 16, 2007, File No. 001-14768)

+10.12 NSTAR Excess Benefit Plan, effective August 25, 1999 (Exhibit 10.1 1999 NSTAR Form 10-K/A filed September 29, 2000, File No. 001-14768)

+10.12.1 NSTAR Excess Benefit Plan, incorporating the NSTAR 409A Excess Benefit Plan, as amended and restated effective January 1, 2008, dated December 24, 2008 (Exhibit 10.1.1 2008 NSTAR Form 10-K filed February 9, 2009, File No. 001-14768)

+10.13 NSTAR Supplemental Executive Retirement Plan, effective August 25, 1999 (Exhibit 10.2,1999 NSTAR Form 10-K/A filed September 29, 2000, File No. 001-14768)

+10.13.1 NSTAR Supplemental Executive Retirement Plan, incorporating the NSTAR 409A Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008, dated December 24, 2008 (Exhibit 10.2.1, 2008 NSTAR Form 10-K filed February 9, 2009, File No. 001-14768)

+10.14 Special Supplemental Executive Retirement Agreement between Boston Edison Company and Thomas J. May dated March 13, 1999, regarding Key Executive Benefit Plan and Supplemental Executive Retirement Plan (Exhibit 10.3, 1999 NSTAR Form 10-K/A filed September 9, 2000, File No. 001-14768)

+10.15 Amended and Restated Change in Control Agreement by and between NSTAR and Thomas J. May dated November 15, 2007 (Exhibit 10.5, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

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+10.16 NSTAR Deferred Compensation Plan, (Restated Effective August 25, 1999) (Exhibit 10.10, 1999 NSTAR Form 10-K/A filed September 29, 2000, File No. 001-14768)

+10.16.1 NSTAR Deferred Compensation Plan, incorporating the NSTAR 409A Deferred Compensation Plan, as amended and restated effective January 1, 2008, dated December 24, 2008 (Exhibit 10.6.1, 2008 NSTAR Form 10-K filed February 9, 2009, File No. 001-14768)

+10.17 NSTAR 2007 Long Term Incentive Plan, effective May 3, 2007 (Exhibit 10.2, NU Registration Statement on Form S-8 filed on May 8, 2012)

+10.17.1 Deferred Common Share/Dividend Equivalent Award, Stock Option Grant, Option Certificate and Performance Share Award/Dividend Equivalent Award Agreement Under the NSTAR 2007 Long Term Incentive Plan, by and between NSTAR and Thomas J. May, dated January 24, 2008 (Exhibit 10.8.1, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.17.2 Deferred Common Share/Dividend Equivalent Award, Stock Option Grant, Option Certificate and Performance Share Award/Dividend Equivalent Award Agreement Under the NSTAR 2007 Long Term Incentive Plan, by and between NSTAR and James J. Judge, dated January 24, 2008 (Exhibit 10.8.2, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.17.3 Deferred Common Share/Dividend Equivalent Award, Stock Option Grant, Option Certificate and Performance Share Award/Dividend Equivalent Award Agreement Under the NSTAR 2007 Long Term Incentive Plan by and between NSTAR and NSTAR's other Senior Vice Presidents and Vice Presidents, dated January 24, 2008 (in form) (Exhibit 10.8.6, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.18 Amended and Restated Change in Control Agreement by and between James J. Judge and NSTAR, dated November 15, 2007 (Exhibit 10.9, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.19 NSTAR Trustees' Deferred Plan (Restated Effective August 25, 1999), dated October 20, 2000 (Exhibit 10.4, NSTAR Form 10-Q for the quarter ended September 30, 2000 filed November 14, 2000, File No. 001-14768)

10.20.1 NSTAR Trustees' Deferred Plan, incorporating the 409A Trustees' Deferred Plan, effective January 1, 2008, dated December 24, 2008 (Exhibit 10.10.1, 2008 NSTAR Form 10-K filed February 9, 2009, File No. 001-14768)

+10.20 Master Trust Agreement between NSTAR and State Street Bank and Trust Company (Rabbi Trust), effective August 25, 1999 (Exhibit 10.5, NSTAR Form 10-Q for the Quarter Ended September 30, 2000 filed November 14, 2000, File No. 001-14768)

+10.21 Amended and Restated Change in Control Agreement by and between NSTAR's other Senior Vice Presidents and NSTAR (in form), dated November 15, 2007 (Exhibit 10.15, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.22 Amended and Restated Change in Control Agreement between NSTAR's Vice Presidents and NSTAR (in form), dated November 15, 2007 (Exhibit 10.16, 2007 NSTAR Form 10-K filed February 11, 2008, File No. 001-14768)

+10.23 Currently effective Change in Control Agreement between NSTAR's Vice Presidents and NSTAR (in form) (Exhibit 10.17, 2009 NSTAR Form 10-K filed February 25, 2010, File No. 001-14768)

+10.24 Executive Retention Award Agreement, dated November 19, 2010, by and between NSTAR and James J. Judge (Exhibit 99.2, NSTAR Current Report on Form 8-K filed November 22, 2010, File No. 001-14768)

10.25 MDTE Order approving Rate Settlement Agreement dated December 31, 2005 (Exhibit 99.2, NSTAR Current Report on Form 8-K filed January 4, 2006, File No. 001-14768)

(E) NU and WMECO

10.1 Lease and Agreement by and between WMECO and Bank of New England, N.A., with BNE Realty Leasing Corporation of North Carolina dated as of December 15, 1988 (Exhibit 10.63, 1988 NU Form 10-K, File No. 001-05324)

*12. Ratio of Earnings to Fixed Charges

(A) Northeast Utilities

(B) The Connecticut Light and Power Company

(C) NSTAR Electric Company

(D) Public Service Company of New Hampshire

(E) Western Massachusetts Electric Company

*21. Subsidiaries of the Registrant

*23. Consents of Independent Registered Public Accounting Firm

*31. Rule 13a – 14(a)/15 d – 14(a) Certifications

(A) Northeast Utilities

31 Certification of Thomas J. May, Chairman, President and Chief Executive Officer of NU required by Rule 13a – 14(a)/15d – 14 (a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

31.1 Certification of James J. Judge, Executive Vice President and Chief Financial Officer of NU required by Rule 13a – 14 (a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(B) The Connecticut Light and Power Company

31 Certification of Thomas J. May, Chairman of CL&P required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

31.1 Certification of James J. Judge, Executive Vice President and Chief Financial Officer of CL&P required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(C) NSTAR Electric Company

31 Certification of Thomas J. May, Chairman of NSTAR Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

31.1 Certification of James J. Judge, Executive Vice President and Chief Financial Officer of NSTAR Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(D) Public Service Company of New Hampshire

31 Certification of Thomas J. May, Chairman of PSNH required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

31.1 Certification of James J. Judge, Executive Vice President and Chief Financial Officer of PSNH required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(E) Western Massachusetts Electric Company

31 Certification of Thomas J. May, Chairman of WMECO required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

31.1 Certification of James J. Judge, Executive Vice President and Chief Financial Officer of WMECO required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

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*32 18 U.S.C. Section 1350 Certifications

(A) Northeast Utilities

32 Certification of Thomas J. May, Chairman, President and Chief Executive Officer of Northeast Utilities and James J. Judge, Executive Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(B) The Connecticut Light and Power Company

32 Certification of Thomas J. May, Chairman of The Connecticut Light and Power Company and James J. Judge, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(C) NSTAR Electric Company

32 Certification of Thomas J. May, Chairman of NSTAR Electric Company and James J. Judge, Executive Vice President and Chief Financial Officer of NSTAR Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(D) Public Service Company of New Hampshire

32 Certification of Thomas J. May, Chairman of Public Service Company of New Hampshire and James J. Judge, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

(E) Western Massachusetts Electric Company

32 Certification of Thomas J. May, Chairman of Western Massachusetts Electric Company and James J. Judge, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated February 25, 2015

*101.INS XBRL Instance Document

*101.SCH XBRL Taxonomy Extension Schema

*101.CAL XBRL Taxonomy Extension Calculation

*101.DEF XBRL Taxonomy Extension Definition

*101.LAB XBRL Taxonomy Extension Labels

*101.PRE XBRL Taxonomy Extension Presentation