NORTHEAST UTILITIES
Form 10-K
February 25, 2015

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

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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:

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cyber breaches, acts of war or terrorism, or grid disturbances,

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actions or inaction of local, state and federal regulatory, public policy and taxing bodies,

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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,

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fluctuations in weather patterns,

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changes in laws, regulations or regulatory policy,

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changes in levels or timing of capital expenditures,

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disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly,

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developments in legal or public policy doctrines,

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technological developments,

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changes in accounting standards and financial reporting regulations,

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actions of rating agencies, and

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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

NSTAR ELECTRIC COMPANY AND SUBSIDIARY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

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:

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The Connecticut Light and Power Company (CL&P), a regulated electric utility that serves residential, commercial and industrial customers in parts of Connecticut;

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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%

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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:

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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):

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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.

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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.

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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:

	NSTAR Electric		WMECO	
(Thousands of Dollars, except percentages)	**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:

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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.

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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.

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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.

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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.

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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.

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An energy efficiency charge that represents a legislatively-mandated charge to collect costs for energy efficiency programs.

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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*.

The following table shows the sources of PSNH's 2014 electric franchise retail revenues based on categories of customers:

		PSNH	
(Thousands of Dollars, except percentages)		**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:

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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.

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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.

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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.

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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.

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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.

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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 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:

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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;

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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

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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.

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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

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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

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

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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 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.

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.

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:					
	$ 7,741,856	$ 7,301,204	$ 6,273,787	$ 4,465,657	$ 4,898,167

Operating Revenues					
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	8.4	8.3	7.9	10.1	10.7

Average Common Equity (%) (f)					
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:

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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.

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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.

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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:

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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.

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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.

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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.

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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.

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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:

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Cash and cash equivalents totaled $38.7 million as of December 31, 2014, compared with $43.4 million as of December 31, 2013.

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Investments in property, plant and equipment totaled \$1.6 billion in 2014 and \$1.5 billion in 2013.

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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.

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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.

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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.

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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.

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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

Electric	NU Sales Volumes (GWh) 2014	2013	NU Percentage Increase/ (Decrease)	CL&P Percentage Increase/ (Decrease)	NSTAR Electric Percentage Decrease	PSNH Percentage Increase/ Decrease	WMECO Percentage 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

Firm Natural Gas	NU Sales Volumes (million cubic feet) 2014	2013	Percentage 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

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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.

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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:

	For the Years Ended December 31,		
(Millions of Dollars)	**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			**NSTAR Electric**		
	For the Years Ended December 31,			**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	**WMECO**
	For the Years Ended December 31,	**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.

<u>DPU Storm Penalties</u>: 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:

<u>Distribution Rates</u>: 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.

<u>CL&P 2014 Storm Order</u>: 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.

<u>CL&P Standard Service and Last Resort Service Rates</u>: 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:

	Increase in Pension Plan Cost		Increase in PBOP Plan Cost	
(Millions of Dollars)	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:

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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.

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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.

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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.

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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:

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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.

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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.

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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

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

	As of December 31,	
(Thousands of Dollars)	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

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

(Thousands of Dollars, Except Share Information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
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.

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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

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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

	For the Years Ended December 31,		
(Thousands of Dollars)	2014	2013	2012
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

	2014	2013	2012
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 Stock	 Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Stockholder's Equity
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

	2014	2013
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

	For the Years Ended December 31,		
(Thousands of Dollars)	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

	For the Years Ended December 31,		
(Thousands of Dollars)	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 Decem