CONNECTICUT LIGHT & POWER CO
Form 10-K
February 25, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2010
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) One Federal Street Building 111-4 Springfield, Massachusetts 01105 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
1-6392		02-0181050

	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	
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 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

Public Service Company of New Hampshire and Western Massachusetts Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are 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**
ü	

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
	ü

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
ü	

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. [**ü**]

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	ü		
The Connecticut Light and Power Company			ü
Public Service Company of New Hampshire			ü
Western Massachusetts Electric Company			ü

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

	Yes	No
Northeast Utilities		ü
The Connecticut Light and Power Company		ü
Public Service Company of New Hampshire		ü
Western Massachusetts Electric Company		ü

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, 2010) was **$4,486,982,187** based on a closing sales price of **$25.48** per share for the 176,098,202 common shares outstanding on June 30, 2010. **Northeast Utilities** holds all of the 6,035,205 shares, 301 shares, and 434,653 shares of the outstanding common stock of **The Connecticut Light and Power Company, Public Service Company of New Hampshire** and **Western Massachusetts Electric Company,** respectively.

Indicate the number of shares outstanding of each of the registrants' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding as of January 31, 2011
Northeast Utilities	
Common shares, $5.00 par value	176,504,390 shares
The Connecticut Light and Power Company	
Common stock, $10.00 par value	6,035,205 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

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated

Portions of the Northeast Utilities Proxy Statement expected to be dated March 30, 2011	Part III

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:

Boulos	E.S. Boulos Company
CL&P	The Connecticut Light and Power Company
HWP	HWP Company, formerly the Holyoke Water Power Company
NGS	Northeast Generation Services Company and subsidiaries
NGS Mechanical	NGS Mechanical, Inc.
NPT	Northern Pass Transmission LLC, a jointly owned limited liability company, held by NUTV and NSTAR Transmission Ventures, Inc. on a 75 percent and 25 percent basis, respectively
NUTV	NU Transmission Ventures, Inc.
NU or the Company	Northeast Utilities and subsidiaries
NU Enterprises	NU Enterprises, Inc., the parent company of Select Energy, NGS, NGS Mechanical, SECI and Boulos
NUSCO	Northeast Utilities Service Company
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO and other subsidiaries, including HWP, RRR (a real estate subsidiary), and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, and Yankee Energy Financial Services Company)
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's Regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH and WMECO, the generation activities of PSNH and WMECO, Yankee Gas, a natural gas local distribution company, and NPT
RRR	The Rocky River Realty Company
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc., a former subsidiary of NU Enterprises
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

CDEP	Connecticut Department of Environmental Protection
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission

SEC	Securities and Exchange Commission
USDEP	U.S. Department of Environmental Protection

OTHER:

2010 Healthcare Act	Patient Protection and Affordable Care Act
2010 Tax Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act
AFUDC	Allowance For Funds Used During Construction
AMI	Advanced metering infrastructure
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CAAA	Clean Air Act Amendments
CERCLA	The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
CfD	Contract for Differences
CO_2	Carbon dioxide
CSC	Connecticut Siting Council
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
CYAPC	Connecticut Yankee Atomic Power Company
EFSB	Massachusetts Energy Facilities Siting Board
EIA	Energy Independence Act
EMF	Electric and Magnetic Fields

EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gas
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
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	H.Q. Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
KV	Kilovolt
KWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Last resort service
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up of Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001.
MMBtu	One million British thermal units
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solution
NO_x	Nitrogen oxide
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NPDES	National Pollutant Discharge Elimination System
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NWPP	Northern Wood Power Project
PBO	Projected Benefit Obligation
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
PGA	Purchased Gas Adjustment
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 segments excluding the wholesale transmission segment
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
RTO	Regional Transmission Organization
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide

SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company
VIE	Variable interest entity
WWL Project	The construction of a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of Yankee Gas' LNG plant
YAEC	Yankee Atomic Electric Company
Yankee Companies	Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company and Maine Yankee Atomic Power Company

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

2010 Form 10-K Annual Report
Table of Contents

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

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," "we," "our," and "us" refer to Northeast Utilities and its consolidated subsidiaries.

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, 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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actions or inaction by local, state and federal regulatory 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

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changes in weather patterns

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changes in laws, regulations or regulatory policy

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changes in levels and 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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fluctuations in the value of our remaining competitive contracts

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actions of rating agencies

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The expected timing and likelihood of completion of the proposed merger with NSTAR, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, as well as the ability to successfully integrate the businesses, and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect 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 management to predict all of such factors, nor can it 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 and estimates in the accompanying *Management s Discussion and Analysis* and *Combined Notes to Consolidated Financial Statements*. We encourage you to review these items.

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

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 Annual Report on Form 10-K.

PROPOSED MERGER WITH NSTAR

On October 18, 2010, we and NSTAR announced that each company s Board of Trustees unanimously approved a Merger Agreement (the merger agreement) to combine the two companies. The transaction was structured as a merger of equals in a tax-free exchange. Upon the terms and subject to the conditions set forth in the merger agreement, at closing, NSTAR will become a wholly-owned subsidiary of NU. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England.

Under the terms of the merger agreement, NSTAR shareholders would receive 1.312 NU common shares for each common share of NSTAR that they own (the "exchange ratio"). The exchange ratio was structured to result in a no premium merger and is based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Following completion of the merger, common shares of the post-transaction company will be owned approximately 56 percent by NU shareholders and approximately 44 percent by former NSTAR shareholders. We anticipate that we will issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Following the closing of the merger, our next quarterly dividend per common share will be increased to an amount that is equivalent to NSTAR s last quarterly dividend per common share paid prior to the closing, divided by the exchange ratio. Based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, that would result in NU s quarterly dividend being increased by approximately 18 percent to approximately $0.325 per share, or approximately $1.30 per share on an annualized basis as compared to NU's current annualized dividend of $1.10 per share. NU filed its joint proxy statement/prospectus with the SEC on January 5, 2011 and scheduled a special meeting of shareholders for March 4, 2011, at which shareholders will vote on whether to approve the merger.

Completion of the merger is subject to various customary conditions, including approval by holders of two-thirds of the outstanding common shares of each company and receipt of all required regulatory approvals, including those of the Massachusetts DPU, the FERC and the NRC. We received approval from the FCC on January 4, 2011, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. Several intervening parties have applied to participate in the regulatory review of the merger and have raised various issues that they believe the regulatory agencies should examine in the course of the proceedings.

In November 2010, the DPUC issued a draft decision stating it lacked jurisdiction over the merger. In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC to reconsider its draft decision. In January 2011, the DPUC issued an Administrative Order stating that it plans to hold a hearing to determine if it has jurisdiction over the merger. Oral arguments surrounding the draft decision were held in February 2011. The DPUC plans to hold an informational hearing at a date to be determined. In addition, legislation proposing to give the DPUC jurisdiction over the merger may be introduced in the Connecticut legislature.

THE COMPANY

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by FERC under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned utility subsidiaries:

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

Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire and continues to own 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

Yankee Gas Services Company (Yankee Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut.

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises. As of December 31, 2010, NU Enterprises business consisted of (i) Select Energy s few remaining energy wholesale marketing contracts, which are being wound down, and (ii) NU Enterprises electrical contracting business.

Although NU, CL&P, PSNH and WMECO each report their financial results separately, we also include information in this report on a segment, or line-of-business, basis - the distribution segment (which also includes the generation businesses of PSNH and WMECO and our natural gas distribution business) and the transmission segment. Our Regulated companies accounted for approximately 99 percent of our total earnings of $387.9 million for 2010, with electric distribution representing approximately 45 percent, natural gas distribution representing approximately 8 percent and electric transmission representing approximately 46 percent of consolidated earnings. The remaining 1 percent of our 2010 earnings comes from our competitive businesses.

REGULATED ELECTRIC DISTRIBUTION

General

NU s electric distribution segment consists of the distribution businesses of CL&P, PSNH and WMECO, which are primarily engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts, respectively, plus PSNH s regulated electric generation business and WMECO s solar generation. The following table shows the sources of 2010 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	59%
Commercial	33%
Industrial	7%
Other	1%
Total	100%

A summary of changes in the Regulated companies retail electric sales (GWh) for 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

	2010	2009	Percentage Increase/ (Decrease)	Weather Normalized Percentage (Decrease)
Residential	14,913	14,412	3.5%	(0.7)%
Commercial	14,506	14,474	0.2%	(2.8)%
Industrial	4,481	4,423	1.3%	(1.5)%
Other	330	336	(1.4)%	(1.4)%
Total	34,230	33,645	1.7%	(1.7)%

Total retail electric sales for all three electric companies were higher in 2010 compared to 2009 due primarily to warmer than normal weather in the summer of 2010 and colder than normal weather in December 2010. Residential sales benefitted the most from the weather in 2010 and were higher for all three electric companies in 2010 compared to 2009.

On a weather normalized basis, retail sales for all three electric companies were lower in 2010 compared to 2009. We believe the decrease was due in part to increased conservation efforts by our customers and the continuing effects of the weak economy.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

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, 2010, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut. CL&P does not own any electric generation facilities. In 2010, CL&P had contracts to purchase the electric output from eighteen IPP generators. The term of two of these contracts ended in 2010. In 2011 the sixteen remaining generators are anticipated to provide approximately two million MWh per year through March 2015, with purchase quantities dropping significantly from 2015 through 2024, when the term of the last IPP contract ends. CL&P sells the output of these contracts into the ISO New England market, crediting customer energy charges with the proceeds. CL&P has entered into eleven contracts with renewable energy generators under a state program known as Project 150, and UI has entered into 2 other similar contracts under Project 150. CL&P and UI will share the costs and benefits of these contracts on an 80 percent and 20 percent basis, respectively. This cost sharing split is independent of the specific utility that is the counterparty to the contract. It is currently projected that the first of these renewable energy projects will commence commercial operation in 2011.

The following table shows the sources of 2010 electric franchise retail revenues for CL&P based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	61%
Commercial	32%
Industrial	6%
Other	1%
Total	100%

Rates

CL&P is subject to regulation by the Connecticut DPUC, which, among other things, has jurisdiction over its rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency 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.

The CTA is a charge assessed to recover stranded costs associated with electric industry restructuring as well as various IPP contracts. The SBC recovers costs associated with various hardship and low income programs as well as payments to municipalities to compensate them for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring. The CTA and SBC are annually reconciled to actual costs incurred, with any difference refunded to, or recovered from, customers.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains their electric distribution company. Under "Standard Service" rates for customers with less than 500 KW of demand and "Supplier of Last Resort Service" rates for customers with 500 KW of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes the cost to such customers through a combined GSC and FMCC on customers' bills. The combined GSC and FMCC charges for both types of service recover all of the costs of procuring energy from CL&P's wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of the DPUC.

Although more CL&P customers chose competitive energy suppliers in 2010 than in 2009, CL&P continues to supply approximately 40 percent of its customer load at Standard Service or Supplier of Last Resort Service rates while the other 60 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 delivery business or its operating income.

Distribution Rates: On June 30, 2010, the DPUC issued a final order in CL&P s most recent retail rate case approving annualized distribution rate increases of $63.4 million effective July 1, 2010 and an incremental $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the final payment of CL&P s RRBs. In its decision, the DPUC also maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent. In 2010, CL&P earned a distribution segment regulatory ROE of 7.9 percent, compared to 7.3 percent in 2009, and expects to earn a distribution segment regulatory ROE of approximately 9 percent in 2011.

In May 2010, the Connecticut Legislature approved a state budget for the 2010-2011 fiscal year, which calls for the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds (ERRBs) that would be amortized over eight years. These bonds will be repaid through a charge on the bills of customers of CL&P and other Connecticut electric distribution companies. For CL&P, the revenue to pay interest and principal on the bonds would come from a continuation of a portion of its CTA, which would have otherwise ended by December 31, 2010 with the final payment of the principal and interest on its RRBs, and the diversion of about one-third of the annual funding for C&LM programs beginning in April 2012. A lawsuit pending against the DPUC to prevent the issuance of the ERRBs is pending and several bills seeking to modify or prevent the issuance have been proposed before the state legislature.

On March 31, 2010, CL&P filed with the DPUC an AMI and dynamic pricing plan concluding that a full deployment of AMI meters accompanied by dynamic pricing options for all CL&P customers would be cost beneficial under a set of reasonable assumptions, identified as the "base case scenario." Under the base case scenario, capital expenditures associated with the installation of the meters are estimated at $296 million. CL&P has proposed beginning installation of meters in late 2012 and finishing in 2016.

CL&P has a transmission adjustment clause as part of its retail distribution rates, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, thereby recovering all of its transmission expenses on a timely basis.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy to serve its Standard Service and Supplier of Last Resort Service loads from a variety of competitive sources through periodic RFPs. CL&P enters into supply contracts for Standard Service periodically for periods of up to three years to mitigate price volatility for its residential and small and medium load commercial and industrial customers. CL&P enters into supply contracts for Supplier of Last Resort service for larger commercial and industrial

customers every three months. Currently, CL&P has contracts in place with various suppliers for all of its Standard Service loads through 2011, 40 percent of expected load for 2012, and 10 percent of expected load for 2013. CL&P s contracts for its Supplier of Last Resort Service loads extend through the second quarter of 2011.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH s distribution business (which includes its generation business) consists primarily of the generation, purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2010, PSNH furnished retail franchise electric service to approximately 497,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of primarily fossil-fueled electricity generation assets. Included in those generation assets is its 50 MW wood-burning Northern Wood Power Project at its Schiller Station in Portsmouth, New Hampshire, and approximately 70 MW of hydroelectric generation. PSNH also has contracts with 18 IPPs, the output of which it either uses to serve its customer load or sells into the market.

PSNH is constructing its Clean Air Project, a sulfur dioxide and mercury scrubber at its Merrimack coal-fired generation station, which is currently expected to cost $430 million. The project is scheduled for completion in mid-2012. PSNH will recover all related costs through its ES rates described below.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	54%
Commercial	36%
Industrial	9%
Other	1%
Total	100%

Rates

PSNH is subject to regulation by the NHPUC, which has jurisdiction over, among other things, rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of facilities.

PSNH s ES rate recovers its generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs, including expenses incurred under mandated power contracts and other long-term investments and obligations. PSNH has 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 time and recovers the costs of these bonds through the SCRC rate.

On an annual basis, PSNH files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. The difference between ES/SCRC revenues and ES/SCRC costs are included in the ES/SCRC rate calculations and refunded to/recovered from customers in the subsequent period approved by the NHPUC.

The TCAM allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted July 1 of each year.

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement of PSNH s rate case that had commenced in 2009, allowing a net distribution rate increase of $45.5 million on an annualized basis to be effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years, respectively. PSNH agreed not to file a new distribution rate request that would be effective prior to July 1, 2015. During the term of the settlement, PSNH can only propose changes to its permanent distribution rate level when its 12-month distribution ROE falls below 7 percent for two consecutive quarters or certain specified external events, such as major storms, occur. If PSNH s 12-month ROE rolling average is greater than 10 percent, anything over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent. PSNH s distribution segment regulatory ROE was 10.2 percent (including generation) in 2010, compared to 7.2 percent in 2009. We expect PSNH s distribution segment regulatory ROE will be approximately 9 percent in 2011.

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 elect to use a third party supplier. Prior to 2009, PSNH experienced only a minimal amount of customer migration. However, customer migration levels began to increase significantly in 2009 as energy costs decreased from their historic high levels and competitive energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. By the end of 2010, approximately 2 percent of all of PSNH s customers (approximately 32 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs of PSNH s generation assets must be spread over a smaller group of customers and lower sales volume. The customers that did not switch to a third party supplier, predominately residential and small commercial and industrial customers, are now paying a larger proportion of these fixed costs.

The NHPUC opened a proceeding in 2010 to consider the effect of customer migration on ES rates for customers, principally residential and small commercial and industrial customers, remaining on PSNH default energy service. As part of this docket, the NHPUC stated its intention to explore the interplay of customer choice, migration issues and power procurement options for PSNH.

PSNH cannot predict if the upward pressure on ES rates will continue into the future, as future customer migration levels, which are dependent on market prices and supplier alternatives, are uncertain. If future market prices once more exceed the average ES rate level, some or all of these customers on third party supply may migrate back to PSNH.

Sources and Availability of Electric Power Supply

During 2010, about 88 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 third parties. The remaining 12 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 2011 in a similar manner.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO s distribution business consists primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2010, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western third of Massachusetts. Following electric industry restructuring in the 1990s, WMECO sold all of its generating facilities and now purchases its energy requirements from competitive suppliers. In 2009, pursuant to the Massachusetts Green Communities Act, WMECO was authorized to install 6 MW of solar energy generation in its service territory. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility at a site in Pittsfield, Massachusetts, which began producing electricity in late 2010. In January 2011, WMECO announced its plans to develop a second solar generation facility at a site in Springfield, Massachusetts. This facility will accommodate 17,000 solar panels, producing up to 4.2 MW of solar energy. WMECO will sell all energy and other products from its solar generation facilities into the ISO New England market. WMECO had a contract with one IPP generator in 2010, the output of which WMECO sold into the ISO New England market. The term of this contract ended on December 31, 2010.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	57%
Commercial	33%
Industrial	9%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts DPU, which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, acquisition of securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities. WMECO's present general rate structure 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 operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under state law, WMECO's customers are entitled to choose their energy suppliers, while WMECO remains their distribution company. WMECO purchases electric power from competitive suppliers for, and passes through the cost to, those customers who do not choose a competitive energy supplier (basic service). Basic service charges are adjusted and reconciled on an annual basis. Most of WMECO's residential and small commercial and industrial customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and industrial customers have opted for a competitive energy supplier.

WMECO continues to supply approximately 50 percent of its customer load at basic service rates while the other 50 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 WMECO s delivery business or its operating income.

WMECO recovers certain costs through various tracking mechanisms in its retail rates, including transmission costs, pension costs and prudently incurred stranded costs (a portion of which have been financed through securitization by issuing RRBs) with periodic true-up adjustments.

6

Distribution Rates: On January 31, 2011, the DPU issued a final decision in WMECO s July 2010 rate application, granting a $16.8 million annualized rate increase in distribution revenues and an allowed ROE of 9.6 percent effective February 1, 2011. The DPU also authorized a full decoupling mechanism, whereby actual revenue billed by WMECO would be reconciled with WMECO s target revenue on an annual basis, WMECO s request to recover balances of certain active hardship account balances and the recovery of certain storm costs over five years. The DPU did not authorize rate recovery of a proposed $20 million average increase in WMECO s capital spending plan. WMECO s distribution segment regulatory ROE was 4.6 percent in 2010 compared to 8.4 percent in 2009. We expect WMECO s distribution segment regulatory ROE will be approximately 9 percent in 2011.

WMECO is subject to SQ metrics that measure safety, reliability and customer service, and WMECO pays any charges incurred for failure to meet such metrics to customers. WMECO will not be required to pay an assessment charge for its 2010 performance results as WMECO performed at target for all of its SQ metrics in 2010.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. However, the Company does not expect it will conduct a pilot prior to 2012.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets (other than its recently constructed solar generation) and purchases its energy requirements from a variety of competitive sources through periodic RFPs. For basic service power supply, WMECO issues RFPs periodically, consistent with DPU regulations.

REGULATED GAS DISTRIBUTION YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 206,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in both 2010 and 2009 was approximately 52.5 Bcf. Yankee Gas provides 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 gas for their heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase natural gas from Yankee Gas. Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas service territory buy gas supply and delivery only from Yankee Gas while commercial and industrial customers have choice in their gas suppliers. Yankee Gas offers firm transportation service to its commercial and industrial customers who purchase gas from sources other than Yankee Gas as well as interruptible transportation and interruptible gas sales service to those commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice. Yankee Gas can interrupt service to these customers during peak demand periods or at any other time to maintain distribution system integrity. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which enables the company to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher.

The following table shows the sources of 2010 gas operating revenues based on categories of customers:

Sources of Revenue	**% of Total Revenues**
Residential	51%
Commercial	30%
Industrial	16%
Other	3%
Total	100%

A summary of firm natural gas sales in million cubic feet for Yankee Gas for 2010 and 2009 and the percentage changes in 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

Firm Natural Gas Sales (Mcf)

	2010	**2009**	**Percent Decrease/ Increase**	**Weather Normalized Percentage (Decrease)**
Residential	13,403	13,562	(1.2)%	4.9%
Commercial	14,982	14,063	6.6%	12.1%
Industrial	14,866	14,825	0.3%	1.7%
Total	43,251	42,450	1.9%	6.2%

Yankee Gas firm natural gas sales are subject to many of the same influences as our retail electric sales, but they have recently benefitted from a favorable price for natural gas relative to competing fuels resulting in commercial and industrial customers switching from interruptible service to firm service, and the addition of gas-fired distributed generation in Yankee Gas service territory. Actual firm natural gas sales in 2010 were higher than 2009 despite the milder weather during the first quarter 2010 heating season. Firm natural gas sales benefitted from these trends and from a large commercial customer who began to take service from Yankee Gas mid-way through the third quarter of 2009 and continued to take service throughout all of 2010.

In April 2010, Yankee Gas commenced construction of its WWL project, a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut coupled with the increase of vaporization output of its LNG plant. The project is expected to cost approximately $57.6 million. In 2010, approximately $26.6 million was spent on construction of the WWL project, which included construction of a segment of pipeline connecting the Cheshire and Wallingford distribution systems. The remainder of the pipeline construction and the expansion of the vaporization capacity of the LNG facility are expected to be completed in the fourth quarter of 2011

Rates

Yankee Gas is subject to regulation by the DPUC, which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities.

Distribution Rates: On January 7, 2011, Yankee Gas filed an application with the DPUC to raise natural gas distribution rates by $32.8 million, or 7.3 percent, to be effective July 1, 2011, and by an additional $13 million, or 2.8 percent, to be effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized ROE of 10.1 percent, that $57.6 million of costs associated with the WWL project be placed into rates, and that a substantial increase in capital funding to replace bare steel and cast iron pipe on Yankee Gas' system. A final decision is expected in June 2011. Yankee Gas regulatory ROE was 8.6 percent in 2010 compared to 6.6 percent in 2009. We expect Yankee Gas distribution segment regulatory ROE to be approximately 9 percent in 2011.

Sources and Availability of Natural Gas Supply

The DPUC requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its 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 LNG facility enables Yankee Gas to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher. 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 currently 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. Yankee Gas considers such transportation arrangements adequate for its needs.

ELECTRIC TRANSMISSION

General

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the rules by which they participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent of all market participants, has served since 2005 as the RTO of the New England transmission system. ISO-NE works to ensure the reliability of the system, administers, subject to FERC approval, the independent system operator tariff, oversees the efficient and competitive functioning of the regional wholesale power market and determines which costs of all regional major transmission facilities are shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through formula rates that are approved by the FERC. Our transmission revenues are recovered from New England customers through ISO-NE charges which recover costs of transmission and other transmission-related services provided by all regional transmission owners, with a portion of those revenues collected from the distribution segments of CL&P, PSNH and WMECO.

FERC ROE Decision

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects. All appeals of FERC's orders on the ROE for New England transmission owners have been denied.

8

On November 17, 2008, the FERC issued an order granting certain incentives and rate amendments to National Grid and us for certain components of the proposed NEEWS project, which is described below. The approved incentives include (1) an ROE of 12.89 percent; (2) inclusion of 100 percent CWIP costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our control. Several parties have sought rehearing of this FERC order on which FERC has not yet acted.

Transmission Projects

NEEWS

CL&P and WMECO are continuing to develop and build the NEEWS project, which is comprised of GSRP, the Interstate Reliability Project and the Central Connecticut Reliability Project, and is estimated to cost $1.52 billion in the aggregate (approximately $1.45 billion reflecting the impact of UI s potential investment of up to approximately $69 million as discussed below). CL&P and WMECO commenced substation construction on GSRP in December 2010 and expect to begin overhead line construction in the first half of 2011. We expect GSRP to be placed in service in late 2013 at a cost of approximately $795 million.

CL&P is designing and building the Interstate Reliability Project in coordination with National Grid USA, whose segment of this phase will interconnect with CL&P s at the Connecticut-Rhode Island border. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project. We expect CL&P's share of the costs of this project to be $301 million and that the project will be placed in service in late 2015.

The timing of the Central Connecticut Reliability Project is expected to be twelve months behind the Interstate Reliability Project and cost approximately $338 million. ISO-NE continues to assess the need date for the Central Connecticut Reliability Project and we expect that ISO-NE will conclude its evaluation by mid-2011.

Included as part of NEEWS are $84 million of expenditures for associated reliability related projects, all of which have received siting approval and most are under construction. The in-service dates for these projects range from later this year through 2013.

Northern Pass Transmission Line Project

NPT is a limited liability company jointly formed by NU and NSTAR to construct, own and operate the Northern Pass transmission line, a new HVDC transmission line from the border of Canada and the United States to Franklin, New Hampshire that will interconnect at the border with a new HVDC transmission line being developed by HQ

TransEnergie, the transmission subsidiary of HQ. NUTV, a subsidiary of NU, holds a 75 percent interest in NPT, with NSTAR Transmission Ventures, Inc., a subsidiary of NSTAR, holding the remaining 25 percent. Consistent with FERC's February 11, 2011 order accepting the TSA between NPT and Hydro Renewable Energy that was filed December 15, 2011, NPT will charge Hydro Renewable Energy cost-based rates for firm transmission service over the Northern Pass line for a 40-year term. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project. Upon commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent based on a deemed capital structure for NPT of 50 percent debt and 50 percent equity.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE. The DOE application seeks permission for NPT to construct and maintain facilities that cross the U.S. border and connect to HQ TransEnergie's facilities in Canada. Assuming timely regulatory review and siting approvals, NPT expects to commence construction of the Northern Pass in 2013, with power flowing across the line in late 2015.

We currently estimate that our 75 percent share of the costs to build the Northern Pass transmission project will be approximately $830 million out of total expected costs of approximately $1.1 billion (including capitalized AFUDC).

Other Transmission Transactions

In July 2010, CL&P and UI entered into an agreement under which UI would acquire certain transmission assets within CL&P's portion of each of the NEEWS segments. Under the terms of the agreement, which has received approval from the FERC and the DPUC, UI will have the option to invest up to $69 million or an amount equal to 8.4 percent of CL&P's costs for the assets, which are expected to aggregate approximately $828 million.

On December 17, 2010, CL&P and CTMEEC, a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric companies, entered into an agreement , subject to DPUC approval, under which CTMEEC would acquire a segment of CL&P s high voltage transmission lines in the town of Wallingford, Connecticut. The transaction was approved by FERC on January 31, 2011. The purchase price will be based on the net book value of the assets at the time of the closing of the sale in May 2011, projected to be approximately $42.3 million. CL&P will continue to operate and maintain the lines for CTMEEC.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects generally enter rate base once they are placed in commercial operation. However, 100 percent of the NEEWS projects will enter rate base during their construction period. At the end of 2010, our transmission rate base was approximately $2.8 billion, including approximately $2.1 billion at CL&P, $341 million at PSNH and $269 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.8 billion by the end of 2015, including approximately $830 million at NPT.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding our existing electric generation, transmission and distribution systems and our natural gas distribution system. Our consolidated capital expenditures in 2010 totaled approximately $1 billion, almost all of which ($967 million) was expended by the Regulated companies. The capital expenditures of these companies in 2011 are estimated to total approximately $1.2 billion, $477 million by CL&P, $284 million by PSNH, $287 million by WMECO and $113 million by Yankee Gas. This capital budget includes anticipated costs for all committed capital projects (i.e., generation, transmission, distribution, environmental compliance and others) and those we expect to become committed projects in 2011.

In 2010, CL&P s transmission capital expenditures totaled approximately $107 million, and its distribution capital expenditures totaled approximately $305 million. For 2011, CL&P projects transmission capital expenditures of approximately $137 million and distribution capital expenditures of approximately $337 million. During the period 2011 through 2015, CL&P plans to invest approximately $1 billion in transmission projects, the majority of which will be for NEEWS and $1.9 billon on distribution projects. If all of the distribution and transmission projects are built as proposed, CL&P s rate base for electric transmission is projected to increase from approximately $2.1 billion at the end of 2010 to approximately $2.6 billion by the end of 2015, and its rate base for distribution assets is projected to increase from approximately $2.3 billion to approximately $3.3 billion over the same period.

In 2010, PSNH's transmission capital expenditures totaled approximately $49 million, its distribution capital expenditures totaled approximately $84 million and its generation capital expenditures totaled $177 million. For 2011, PSNH projects transmission capital expenditures of approximately $59 million, distribution capital expenditures of approximately $113 million and generation capital expenditures of approximately $112 million. The bulk of the generation capital expenditures is for the Clean Air Project. During the period 2011 through 2015, PSNH plans to spend approximately $293 million on transmission projects, approximately $621 million on distribution projects, and $274 million on generation projects. If all of the distribution, generation and transmission projects are built as proposed, PSNH s rate base for electric transmission is projected to increase from approximately $341 million at the end of 2010 to approximately $540 million by the end of 2015, and its rate base for distribution and generation assets is projected to increase from approximately $1.2 billion to approximately $1.9 billion over the same period.

In 2010, WMECO's transmission capital expenditures totaled approximately $95 million, its distribution capital expenditures totaled approximately $33.1 million and solar generation expenditures were $10 million. In 2011, WMECO projects transmission capital expenditures of approximately $229 million, distribution capital expenditures of approximately $36 million and $22 million on solar generation. During the period 2011 through 2015, WMECO plans to spend approximately $732 million on transmission projects, with the bulk of that amount to be spent on GSRP, approximately $194 million on distribution projects and $46 million on solar generation. If all of the generation, distribution and transmission projects are built as proposed, WMECO s rate base for electric transmission is projected to increase from approximately $269 million at the end of 2010 to approximately $803 million by the end of 2015 and its rate base for distribution and generation assets is projected to increase from approximately $423 million to approximately $488 million over the same period.

In 2010, Yankee Gas capital expenditures totaled approximately $95 million. For 2011, Yankee Gas projects total capital expenditures of approximately $113 million, approximately $30 million of which is expected to be related to the WWL project, $37 million related to basic business activities such as relocation of conflicting gas facilities and the purchase of meters, tools and information technology; $30 million related to reliability improvements; and $16 million for load growth and new business requests. During the period 2011 through 2015, Yankee Gas plans on making approximately $587 million of capital expenditures, including approximately $30 million on the WWL project. Future capital spending will likely be affected by price differences between the cost of natural gas with respect to home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements. Excluding non-recurring major projects, NU expects that approximately 28 percent of Yankee Gas capital expenditures over the 2011-2015 period to be related to basic business activities, approximately 28 percent related to load growth and new business, and approximately 39 percent related to reliability initiatives, with the balance related to the WWL project. If all of Yankee Gas projects are built as proposed, Yankee Gas investment in its regulated assets is projected to increase from approximately $682 million at the end of 2010 to approximately $969 million by the end of 2015.

FINANCING

NU subsidiaries issued a total of $145 million in long-term debt in 2010. On March 8, 2010, WMECO issued $95 million of senior unsecured notes due March 1, 2020 carrying a coupon rate of 5.1 percent and on April 22, 2010, Yankee Gas issued $50 million of first mortgage bonds through a private placement with a maturity date of April 1, 2020 carrying a coupon rate of 4.87 percent.

In addition, on April 1, 2010, CL&P completed the remarketing of $62 million of tax-exempt secured PCRBs. The PCRBs carry a coupon rate of 1.4 percent until April 1, 2011, at which time CL&P expects to remarket the bonds.

On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, and CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, both replacing five-year credit facilities on similar terms and conditions that were scheduled to expire on November 6, 2010. Like the previous facility, NU s new revolving credit facility allows NU parent to borrow on a short-term or long-term basis, or issue LOCs, up to $500 million in the aggregate. Under their new revolving credit facility, CL&P and PSNH are each able to draw up to $300 million, with WMECO and Yankee Gas each able to draw up to $200 million, all subject to the $400 million maximum aggregate borrowing limit.

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, 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 such companies currently are, and expect to remain in compliance with these covenants.

We have annual sinking fund requirements of $4.3 million continuing in 2011 through 2012, the mandatory tender of $62 million of tax-exempt PCRBs by CL&P on April 1, 2011, at which time CL&P expects to remarket the bonds in the ordinary course. Neither NU nor any of its subsidiaries have any debt maturities until April 1, 2012.

In light of the 2010 Tax Act and the related cash flow benefits, we are currently reevaluating the timing of our previously planned NU common equity issuance. If we complete the proposed merger with NSTAR, we would no longer need to undertake the previously planned $300 million NU common equity issuance in 2012 nor issue any additional equity in the foreseeable future.

NUCLEAR DECOMMISSIONING

General

CL&P, 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 collects decommissioning and closure costs through wholesale FERC-approved rates charged under power purchase agreements with CL&P, PSNH and WMECO and several other New England utilities. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The ownership percentages of CL&P, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	Total
CYAPC	34.5%	5.0%	9.5%	49.0%

MYAPC	12.0%	5.0%	3.0%	20.0%
YAEC	24.5%	7.0%	7.0%	38.5%

Our share of the obligations to support the Yankee Companies under FERC-approved contracts is the same as the ownership percentages above.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including the 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 DPUC, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has jurisdiction over 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, our 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. PSNH owns approximately 1,200 MW of generation assets and expects to spend approximately $430 million on its Clean Air Project, the installation of a wet flue gas desulphurization system at its Merrimack coal station to reduce its mercury and sulfur dioxide emissions. Compliance with additional environmental laws and regulations, particularly air and water pollution control requirements may cause changes in operations or require further investments in new equipment at existing facilities.

Water Quality Requirements

The federal Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a 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 obtaining or renewing all required NPDES or state discharge permits in effect for our facilities. In each of the last three years, the costs incurred by the Company related to compliance with NPDES and state discharge permits have not been material. The Company expects to incur additional costs related to these permits in the future; however, due to uncertainty regarding the imposition of new or additional requirements, the Company is unable to accurately estimate such costs.

Air Quality Requirements

The 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. Installation of continuous emissions monitors and expanded permitting provisions also are included.

In New Hampshire, the Multiple Pollutant Reduction Program capped NO_X, SO_2 and CO_2 emissions beginning in 2007. In addition, a 2006 New Hampshire law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions of its coal fired plants by at least 80 percent (with the co-benefit of reductions in SO_2 emissions as well). The Clean Air Project addresses this requirement. PSNH began site work for this project in November 2008 and is scheduled to complete it by mid-2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generating plants. Because CO_2 allowances issued by any participating state will be usable across all ten RGGI state programs, the individual state CO_2 trading programs, in the aggregate, will 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 began in 2009.

Because neither CL&P nor WMECO currently own any generating assets (other than the solar facilities owned by WMECO, which do not emit CO_2), neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators that provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs are then recoverable from customers.

PSNH anticipates that its generating units will emit between four million and five million tons of CO_2 per year after taking into effect the operation of PSNH s Northern Wood Power Project. Under the RGGI formula, this Project decreased PSNH s responsibility for reducing fossil-fired CO_2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled generating plants during the 2009 through 2011 compliance period. These banked CO_2 allowances will initially comprise approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants to comply with RGGI. Such banked allowances will decrease over time. PSNH expects to satisfy 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.

Each of the states in which we do business also has RPS requirements, which generally require fixed percentages of 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, beginning in 2008 at four percent and ultimately reaching 23.8 percent by 2025. In 2010, the total RPS obligation was 7.5 percent of total generation supplied to customers. 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 both internally generated RECs and purchased 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 do not impact earnings, as these costs are recovered by PSNH through its ES rates charged to customers.

Connecticut's RPS statute requires electricity suppliers to meet renewable energy standards, beginning with a four percent RPS in 2004. This percentage increases each year. For 2010, the requirement was 14 percent with goals of 19.5 percent by 2015 and 27 percent by 2020. CL&P is permitted to pass any costs incurred in complying with RPS on to customers through rates.

Massachusetts RPS program required electricity suppliers to meet a one percent renewable energy standard in 2003 and has a goal of 15 percent by 2015. For 2010, the requirement was five percent. WMECO is permitted to pass any costs incurred in complying with RPS on to customers through rates.

In addition, many states and environmental groups have challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. As a result, it is possible that state and federal regulations could be developed that will impose more stringent limitations on emissions than are currently in effect.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws 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 is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal 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. At December 31, 2010, the liability recorded by us 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 $37.1 million, representing 58 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, through our subsidiaries, currently have partial or full ownership responsibilities at 28 former MGP sites.

HWP, a wholly-owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal electric utility, in 1902. HWP is at least partially responsible for this site and has already conducted substantial investigative and remediation activities. HWP's share of the remediation costs related to this site is not recoverable from customers.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from 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.

We have closely monitored research and government policy developments for many years and will continue to do so. 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, particularly in recent years. The EPA has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and 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 GHG emission reporting beginning in 2012 for 2011 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 risks presented by climate change concerns and issues. 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. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal "cap and trade" laws, or regulations requiring additional capital expenditures at our generating facilities. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers.

Global climate change could potentially impact weather patterns such as increasing the frequency and severity of storms or altering temperatures. These changes could affect our facilities and infrastructure and could also impact energy usage by our 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, or (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.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision that expressly permits the FERC to order decommissioning during the license term. However, the FERC has taken the position that under appropriate circumstances it may order decommissioning of hydroelectric projects at relicensing or may require the establishment of decommissioning trust funds as a condition of relicensing. The FERC may also require project

decommissioning during a license term if a hydroelectric project is abandoned, the project license is surrendered or the license is revoked. PSNH is not presently encountering any of these challenges.

EMPLOYEES

As of December 31, 2010, we employed a total of 6,182 employees, excluding temporary employees, of which 1,847 were employed by CL&P, 1,240 by PSNH, 354 by WMECO, 429 by Yankee Gas and 2,307 were employed by NUSCO. Approximately 2,212 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers and The United Steelworkers and are covered by 11 union agreements.

INTERNET INFORMATION

Our website address is www.nu.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, WMECO's and PSNH'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. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Northeast Utilities, 56 Prospect Street, Hartford, CT 06103.

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 directly 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.

The actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our Regulated companies charge their respective retail and wholesale 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 of 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 or processes (especially due to age); labor disputes; disruptions in the delivery of electricity, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; information security risk, such as a breach of our systems on which sensitive utility customer data and account information are stored; catastrophic events such as fires, explosions, or other similar occurrences; and other unanticipated operations and maintenance expenses and liabilities. The failure of our transmission, distributions and generation systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in operation and maintenance costs. At PSNH, outages at generating stations may be deemed imprudent by state regulators resulting in disallowance of replacement power 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.

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.

We are exposed to the risk that counterparties to various arrangements who owe us money, or 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 or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of 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.

Changes in regulatory or legislative policy and/or regulatory decisions, difficulties in obtaining siting, design or other approvals, global demand for critical resources, environmental or other concerns, or construction of new generation may delay completion of or displace our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected rates of return.

Our transmission construction plans could be affected by new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions, delays in obtaining approvals or difficulty in obtaining critical resources required for construction. Any of such events could cause delays in our construction schedule adversely affecting our ability to achieve forecasted earnings.

The regulatory approval process for our transmission projects requires extensive permitting, design and technical activities. Various factors could result in increased costs and delay construction schedules. These include environmental and community concerns and design and siting issues. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all 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 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 level presently anticipated.

Increases in electric and gas prices and/or a weak economy, can lead to changes in legislative and regulatory policy promoting 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 gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, 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.

Connecticut, New Hampshire and Massachusetts have each investigated revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. In Connecticut, the DPUC authorized decoupling through a rate design that is intended to recover greater distribution revenue through fixed charges, and proportionately less distribution revenue through usage-based charges. In New Hampshire, the NHPUC conducted a decoupling docket and determined that utilities were free to propose decoupling in the context of a rate case and demonstrate the effect decoupling would have on its risk profile and ROE. PSNH has not yet commenced such a proceeding. In Massachusetts, the DPU has required WMECO to adopt full decoupling in its January 31, 2011 rate decision. At this time it is uncertain what impact these decoupling mechanisms will have on our companies.

As a way to promote self-generation and reduce energy costs, Connecticut, Massachusetts, and New Hampshire have taken a greater interest in allowing customers to receive credit for generation produced at a customer-owned generating facility that exceeds their energy needs. In Massachusetts, in accordance with the Green Communities Act, the DPU adopted rules and regulations concerning net metering that will have this effect. Such rules provide a cost recovery mechanism for affected utilities to recover lost revenues. The Massachusetts DPU is expected to hold further proceedings to address net metering in early 2011. In Connecticut, the DPUC opened a docket to review existing state statutes and determine what limitations currently exist in state law concerning net metering. In addition, any legislation in Connecticut to promote self-generation and net metering could impact CL&P   s financial position, results of operations or cash flows. In New Hampshire, new legislation dramatically changed the net metering rules in 2010. This new legislation is meant to encourage net metering from customers with small generators and also provides PSNH a cost recovery mechanism for lost distribution revenue.

Changes in regulatory and/or legislative policy could negatively impact regional transmission 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 relative benefits received. This regional cost allocation is set forth in the Transmission Operating Agreement signed by all of the New England transmission owning utilities. Effective February 1, 2010, this agreement can be modified with the approval of a majority of the transmission owning utilities and 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 is also considering policies to encourage the construction of transmission for renewable generation that could have the effect of imposing costs of inter-regional investment on New England customers.

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. Increases in these costs, 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 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 and WMECO receive approval to recover the costs of these contracts from the DPUC 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.

Migration of customers from PSNH energy service to competitive energy suppliers could increase the cost to the remaining customers of energy produced by PSNH generation assets and decrease our revenues.

PSNH s ES rates have been higher than competitive energy prices offered to some customers in recent years, primarily due to lower natural gas prices. As a result, by the end of 2010, approximately 2 percent of PSNH s retail customers (representing approximately 32 percent of load), mostly large commercial and industrial customers, were buying their energy from competitive suppliers rather than from PSNH. The remaining retail customers are experiencing an increase in the cost of energy service supplied by PSNH by 5 percent to 7 percent due to migration of large commercial and industrial customers and the lower base in which to recover PSNH's fixed generation costs. This increase may in turn cause further migration and further increasing of PSNH energy service rates. This trend could lead to PSNH continuing to lose retail customers and increasing the burden of supporting the cost of its generation facilities on remaining customers and being unable to support the cost of its generation facilities through an ES rate.

The NHPUC is examining this issue in a proceeding in which hearings ended on December 1, 2010. PSNH has suggested transferring some fixed costs of the generation facilities into a nonbypassable charge while intervening competitive suppliers have proposed taking over the purchased power portion of the load not supplied by PSNH s generation. Others have also proposed having PSNH bid all of its generation facilities into the market while an RFP process supplies all of the power for PSNH s energy service. The NHPUC is considering further proceedings to explore these and other issues as well as the NHPUC authority to require PSNH to divest its generation facilities. It is not known what the results of such a proceeding would be, what PSNH may realize as a result of the sale or retirement of one or more of its generation facilities, or to what extent or manner the NHPUC would provide for recovery of any investment in its generation facilities.

Judicial or regulatory proceedings or changes in regulatory or legislative policy could jeopardize completion of, or full recovery of costs incurred by PSNH in constructing, the Clean Air Project.

Pursuant to New Hampshire law, PSNH is building the Clean Air Project at its Merrimack Station in Bow, New Hampshire. Several parties initiated legal proceedings challenging the project. These proceedings, or new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could result in increased costs to the project.

In addition, PSNH s investment in the project after it is completed is subject to prudence review by the NHPUC at the time the project is placed in service. 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 prudency reviews should they occur. 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 condition 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.

Grid disturbances, severe weather, or acts of war or terrorism could negatively impact our business.

Because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business continuity due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage, solar storm activity or terrorist action) on an interconnected system or the actions of another utility. In addition, we are subject to the risk that acts of war or terrorism, including cyber-terrorism could negatively impact the operation of our system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition, results of operations or cash flows.

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. The effect of the failure of our facilities to operate as planned would be particularly burdensome during a peak demand period, such as during the hot summer months.

Market performance or changes in assumptions could require us to make significant contributions to our pension and other post-employment benefit plans.

We provide a defined benefit pension plan and other post-retirement 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, 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 2008 and 2009, due to the financial crisis, the value of our pension assets declined. As a result, we made a contribution of $45 million in 2010 and expect to make an approximate $145 million contribution in 2011. 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, 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," in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent is dependent on dividends from its subsidiaries, primarily the Regulated companies, its bank facility, 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 financial obligations associated with the debt service obligations on its debt and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or to repay borrowings from NU parent; and/or NU parent s ability to access its credit

facility 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 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 to or repay funds due to NU parent or if NU parent cannot access its bank facilities 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.

Risks Related to the Proposed Merger with NSTAR

We may be unable to satisfy the conditions or obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions.

The merger is subject to approval by the shareholders of both NU and NSTAR and numerous other conditions, including the approval of various government agencies. Governmental agencies may not approve the merger or such approvals may impose conditions on the completion, or require changes to the terms of the merger, including restrictions on the business, operations or financial performance of the combined company, which could be adverse to the company's interests. These conditions or changes could also delay or increase the cost of the merger or limit the net income or financial prospects of the combined company.

We will be subject to business uncertainties and contractual restrictions while the merger is pending.

The work required to complete the merger may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the merger instead of on day-to-day management activities, including pursuing other opportunities beneficial to NU. In addition, while the merger is pending our business operations are restricted by the Agreement and Plan of merger to ordinary course of business activities consistent with past practice, which may cause us to forgo otherwise beneficial business opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees.

Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results and we could face litigation concerning the merger, whether or not the merger is consummated.

Failure to complete the merger could negatively affect NU's share price, as well as our future business and financial results. In addition, purported class actions have been brought against us, NSTAR and others on behalf of holders of NSTAR common shares. If these actions or similar actions that may be brought are successful, the costs of completing the merger could increase, or the merger could be delayed or prevented. We cannot make any assurances that we will succeed in any litigation brought in connection with the merger. See Item 3, *Legal Proceedings*, in this Annual Report on Form 10-K for discussion of pending litigation related to the merger.

If the merger is not completed for certain reasons specified in the merger agreement, we may be required to pay NSTAR a termination fee of $135 million plus up to $35 million of certain expenses incurred by NSTAR. In addition, we must pay our own costs related to the merger including, among others, legal, accounting, advisory, financing and filing fees and printing costs, whether the merger is completed or not. Further, if the merger is not completed, we could be subject to litigation related to the failure to complete the merger or other factors, which may adversely affect our business, financial results and share price.

If completed, the merger may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits. If the merger is completed, our ability to achieve the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Item 1B.

Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

18

Item 2.

Properties

Transmission and Distribution System

As of December 31, 2010, our electric operating subsidiaries owned 31 transmission and 422 distribution substations that had an aggregate transformer capacity of 5,302,000 kilovolt amperes (kVa) and 29,861,000 kVa, respectively; 3,094 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 433 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,957 pole miles of overhead and 3,054 conduit bank miles of underground distribution lines; and 539,379 underground and overhead line transformers in service with an aggregate capacity of 37,703,193 kVa.

Electric Generating Plants

As of December 31, 2010, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	5 units	1952-74	947,980
Total - Hydro-Conventional	20 units	1901-83	71,105
Total - Internal Combustion	5 units	1968-70	102,959
Total - Biomass - Steam Plant	1 unit	1954	45,816
Total PSNH Generating Plant	31 units		1,167,860

*

Claimed capability represents winter ratings as of December 31, 2010. The combined nameplate capacity of the generating plants is approximately 1,200 MW.

As of December 31, 2010, WMECO owned the following electric generating plant:

Type of Plant

	Number of Units	Year Installed	Claimed Capability** (kilowatts)
Total - Solar Fixed Tilt, Photovoltaic	1 unit	2010	1,800,000

** Claimed capability represents the direct current nameplate capacity of the plant.

CL&P did not own any electric generating plants during 2010.

Yankee Gas

As of December 31, 2010, Yankee Gas owned 28 active gate stations, approximately 200 district regulator stations and 3,239 miles of natural gas main pipeline. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, a propane facility in Kensington, Connecticut, and three additional propane facilities that are no longer in service and are expected to be sold in 2011.

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 in Title 16 of the Connecticut General Statutes 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. Title 16 of the Connecticut General Statutes was amended by Public Act 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," to prohibit an electric distribution company from owning or operating generation assets. However, Public Act 05-01, "An Act Concerning Energy Independence," allows CL&P to own up to 200 MW of peaking facilities if the DPUC determines that such facilities will be more cost effective than other options for mitigating FMCCs and Locational Installed Capacity (LICAP) costs. In addition, Section 83 of Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency," states that if an existing electric generating plant located in Connecticut is offered for sale, then an electric distribution company, such as CL&P, would be eligible to purchase the generation plant upon obtaining prior approval from the DPUC and a determination by the DPUC that such purchase is in the public interest.

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. The distribution and transmission franchises of PSNH include the power of eminent domain.

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 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 WMECO. 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.

Yankee Gas. Yankee Gas holds valid franchises to sell gas in the areas in which Yankee Gas supplies 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 gas utility under a valid franchise of its own or are not subject to an exclusive franchise of another 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 DPUC 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 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

The Yankee Companies (YAEC, MYAPC, and CYAPC) commenced litigation in 1998 against the DOE charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982 to begin removing spent nuclear fuel from the respective nuclear plants no later than January 31, 1998 in return for payments by each company into the Nuclear Waste Fund. The funds for those payments were collected from regional electric customers. The Yankee Companies initially claimed damages for incremental spent nuclear fuel storage, security, construction and other costs through 2010.

In 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. In December 2006, the DOE appealed the decision and the Yankee Companies filed cross-appeals. The Court of Appeals disagreed with the trial court s method of calculation of the amount of the DOE s liability, among other things, and vacated the decision of the Court of Federal Claims and remanded the case to make new findings consistent with its decision. On September 7, 2010, the trial court issued its decision following remand and awarded CYAPC $39.7 million, YAEC $21.2 million and MYAPC $81.7 million. The DOE filed an appeal and the Yankee Companies cross-appealed. Briefs are due in the first quarter of 2011. The application of any damages that are ultimately recovered to benefit customers, is established in the Yankee Companies' FERC-approved rate settlement agreements, although implementation will be subject to the final determination of the FERC.

In December 2007, the Yankee Companies filed a second round of lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001 and 2002.

2.

Connecticut MGP Cost Recovery

In September 2006, CL&P and Yankee Gas (the NU Companies) filed a complaint against UGI Utilities, Inc. (UGI) in the U.S. District Court for the District of Connecticut seeking past and future remediation costs related to historic MGP operations on thirteen sites currently or formerly owned by the NU Companies (Yankee Gas is responsible for ten of the sites, CL&P for two of the sites, and both companies share responsibility for one site) in a number of different locations throughout the State of Connecticut. The NU Companies allege that UGI controlled operations of the plants at various times throughout the period 1883 to 1941, when UGI was forced to divest its interests.

Investigations and remediation activity and expenditures at the sites are ongoing. A trial was held in April 2009.

On May 22, 2009, the court granted judgment in favor of the NU Companies with respect to the Waterbury-North site, and granted judgment in favor of UGI with respect to the remaining sites. Judgment was entered on March 31, 2010. On April 23, 2010, the NU Companies filed a Notice of Appeal with respect to the court s decision, which has been fully briefed. The Phase II trial, which would determine what portion of the remediation costs at the Waterbury-North site are attributable to UGI's control, is scheduled for August 31, 2011. Any recovery resulting from the case (following the appeal and the Waterbury-North complaint) would flow back to the NU Companies' customers, and the NU Companies would continue to seek recovery as appropriate of remediation and other associated costs with regard to the sites for which no recovery from UGI will be forthcoming.

3.

Litigation Related to the Proposed Merger with NSTAR

In October 2010, NSTAR, the members of the NSTAR board of trustees, NU, and two wholly-owned NU subsidiaries, NU Holding Energy 1 LLC and NU Holding Energy 2 LLC, were named defendants in eight lawsuits (since consolidated) filed in the Superior Court for Suffolk County, Massachusetts, and one lawsuit filed in federal court in the district of Massachusetts. The lawsuits, each of which was brought by a single shareholder, purport to be brought on behalf of classes of NSTAR shareholders opposed to the terms of the merger agreement. The original complaints made virtually identical allegations that, among other things, NSTAR s trustees breached their fiduciary duties by failing to maximize the value to be received by NSTAR s shareholders, and that the other defendants aided and abetted the NSTAR trustees breaches of fiduciary duties. Both the state and federal complaints sought and continue to seek, among other things, to enjoin defendants from consummating the merger and either rescission of the merger, to the extent it is completed, or monetary damages. On December 10, 2010, the state-court plaintiffs filed their consolidated amended complaint, which, in addition to the already-pending claims, alleged that the disclosures in the preliminary joint proxy statement/prospectus NU filed jointly with NSTAR, were insufficiently detailed, pointing to various aspects of the section entitled "The Merger." On January 6, 2011, NU and NSTAR each moved to dismiss the claims asserted against them for failure to state a claim. In addition, NU and NSTAR jointly moved for a protective order staying the discovery that some of the Plaintiffs had served contemporaneously with their complaints. On January 13, 2011, Plaintiffs moved the Court to expedite proceedings in anticipation of their making a subsequent motion for preliminary injunction to enjoin the March 4, 2011 shareholder vote. Plaintiffs also filed a purported "emergency" motion to obtain discovery from Lexicon Partners, NSTAR's financial advisors. NU and NSTAR opposed both motions, which the Court subsequently denied and scheduled a "litigation control" conference for February 28, 2011 "to address proper scheduling of any and all related motions anticipated by the parties." On February 11, 2011, Plaintiffs filed a motion for preliminary injunction seeking to enjoin the March 4, 2011 shareholder vote. NU and NSTAR will file their opposition to the motion on or before February 22, 2011 on the grounds that it lacks any legal or evidentiary basis. There have been no developments in the federal case, in which the plaintiff has never served NSTAR, NU, or any other defendant with his complaint. NU and NSTAR believe both the federal and state lawsuits are without merit and are defending the lawsuits vigorously.

4.

Bankruptcy of Independent Power Producer

On February 1, 2011, an independent power producer, AES Thames, L.L.C. (Thames), which is the counterparty to a CL&P electricity purchase agreement, filed a voluntary petition for bankruptcy in the U.S. Bankruptcy Court in Delaware (Case No. 11-10334). Thames owns and operates a 181 MW coal fired generation plant in Montville, Connecticut providing electric energy to CL&P and process steam to a nearby paperboard manufacturer. Citing market conditions and regulatory and legislative uncertainties, Thames had advised CL&P on January 24, 2011 that it was shutting the plant down for an undetermined period. Under an amendment to the electricity purchase agreement entered into in 1999, Thames agreed to supply CL&P with energy from the plant for a reduced price in exchange for a substantial prepayment. The electricity purchase agreement was due to expire in 2015. CL&P has appeared in the Delaware bankruptcy proceeding and intends to assert all available legal rights to protect its customers interests. Management cannot estimate the effects of this proceeding, but does not believe there will be a material impact on CL&P s financial position, results or operations or cash flows.

5.

Other Legal Proceedings

For further discussion of legal proceedings see the following sections of Item 1, *Business:* "- Regulated Electric Distribution," "-Regulated Gas Distribution - Yankee Gas Services Company," and "- Electric Transmission," 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 Decommissioning" 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, EMF, licensing of hydroelectric projects, and other matters. In addition, see Item 1A, *Risk Factors*, for general information about several significant risks.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the executive officers of NU as of February 24, 2011. 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	41	Vice President - Accounting and Controller.
Gregory B. Butler	53	Senior Vice President and General Counsel.
Jean M. LaVecchia*	59	Vice President - Human Resources of NUSCO.
David R. McHale	50	Executive Vice President and Chief Financial Officer of NU.
Leon J. Olivier	62	Executive Vice President and Chief Operating Officer of NU.
James B. Robb*	50	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	65	Chairman of the Board, President and Chief Executive Officer of NU.

*

Deemed executive officer of NU pursuant to Rule 3b-7 under the Securities Exchange Act of 1934.

Jay S. Buth. Mr. Buth was elected Vice President - Accounting and Controller of NU, CL&P, PSNH and WMECO, effective June 9, 2009. Previously, Mr. Buth served as Controller, and Vice President and Controller at NJR Service Corporation, a subsidiary of New Jersey Resources Corporation, a gas utility holding company, from June 2006 to January 2009. He also served as Director - Finance at Allegheny Energy, Inc. from May 2004 to May 2006.

Gregory B. Butler. Mr. Butler was elected Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, subsidiaries of NU, effective March 9, 2006, and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and a Director of Northeast Utilities Foundation, Inc. effective December 1, 2002. Previously Mr. Butler served as Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005 and Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009 and a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007. Previously Ms. LaVecchia served as Vice President - Human Resources and Environmental Services from May 1, 2001 to December 31, 2004.

David R. McHale. Mr. McHale was elected Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO, effective January 1, 2009, elected a Director of PSNH and WMECO, effective January 1, 2005, of CL&P effective January 15, 2007 and of Northeast Utilities Foundation, Inc. effective January 1, 2005. Previously, Mr. McHale served as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO from January 1, 2005 to December 31, 2008 and Vice President and Treasurer of NU, PSNH and WMECO from July 1998 to December 31, 2004.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008; He also has served as Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; a Director of PSNH and WMECO since January 17, 2005 and a Director of CL&P since September 2001. Previously, Mr. Olivier served as Executive Vice President - Operations of NU from February 13, 2007 to May 12, 2008; Executive Vice President of NU from December 1, 2005 to February 13, 2007; President - Transmission Group of NU from January 17, 2005 to December 1, 2005; and President and Chief Operating Officer of CL&P from September 2001 to January 2005.

James B. Robb. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007 and was elected a Director of CL&P, PSNH and WMECO April 22, 2009. Previously, Mr. Robb served as Managing Director, Russell Reynolds Associates from December 2006 to August 2007; Entrepreneur in Residence, Mohr Davidow Ventures from March 2006 to November 2006; Senior Vice President, Retail Marketing, Reliant Energy, Inc. from December 2003 to December 2006; and Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.

Charles W. Shivery. Mr. Shivery was elected Chairman of the Board, President and Chief Executive Officer of NU effective March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO effective January 19, 2007 and a Director of Northeast Utilities Foundation effective March 3, 2004. Previously, Mr. Shivery served as President (interim) of NU from January 1, 2004 to March 29, 2004; and President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

Item 4.

[RESERVED]

PART II

Item 5.

Market for the Registrants' Common Equity and Related Stockholder Matters

NU. Our common shares are listed on the New York Stock Exchange. The ticker symbol is "NU," although it is frequently presented as "Noeast Util" and/or "NE Util" in various financial publications. The high and low sales prices for the past two years, by quarter, are shown below.

Year	Quarter	High	Low
2010	First	$ 28.00	$ 24.68
	Second	28.21	24.83
	Third	30.25	25.24
	Fourth	32.21	29.51
2009	First	$ 25.05	$ 19.45
	Second	22.40	19.99
	Third	24.72	21.38
	Fourth	26.33	22.54

There were no purchases made by or on behalf of our company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of common stock during the fourth quarter of the year ended December 31, 2010.

As of January 31, 2011, there were 40,210 registered common shareholders of our company on record. As of the same date, there were a total of 195,808,704 common shares issued. There were no unallocated ESOP shares held in the ESOP trust as of December 31, 2010.

Pursuant to NU parent's Shareholder Rights Plan (the "Plan"), NU parent distributed to shareholders of record as of May 7, 1999, a dividend in the form of one common share purchase right (a "Right") for each common share owned by the shareholder. The Rights and the Plan expired at the end of the 10-year term on February 23, 2009.

On February 8, 2011, our Board of Trustees declared a dividend of 27.5 cents per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011.

On October 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on December 31, 2010 to shareholders of record as of December 1, 2010.

On July 12, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on September 30, 2010 to shareholders of record as of September 1, 2010.

On April 13, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on June 30, 2010 to shareholders of record as of June 1, 2010.

On February 9, 2010, our Board of Trustees declared a dividend of 25.625 cents per share, payable on March 31, 2010 to shareholders of record as of March 1, 2010.

On October 13, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on December 31, 2009 to shareholders of record as of December 1, 2009.

On July 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on September 30, 2009 to shareholders of record as of September 1, 2009.

On April 14, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on June 30, 2009 to shareholders of record as of June 1, 2009.

On February 10, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on March 31, 2009 to shareholders of record as of March 1, 2009.

Information with respect to dividend restrictions for us, CL&P, 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, PSNH and WMECO. All of the common stock of CL&P, PSNH and WMECO is held solely by NU.

During 2010 and 2009, CL&P approved and paid $217.7 million and $113.8 million, respectively, of common stock dividends to NU.

During 2010 and 2009, PSNH approved and paid $50.6 million and $40.8 million, respectively, of common stock dividends to NU.

During 2010 and 2009, WMECO approved and paid $14.9 million and $18.2 million, respectively, of common stock dividends to NU.

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.

Item 6.

Selected Consolidated Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and common share information)		**2010**		**2009**		**2008**		**2007**		**2006**
Balance Sheet Data:										
Property, Plant and Equipment, Net	$	9,567,726	$	8,839,965	$	8,207,876	$	7,229,945	$	6,242,186
Total Assets		14,522,042		14,057,679		13,988,480		11,581,822		11,303,236
Total Capitalization (a)		8,627,985		8,253,323		7,293,960		6,667,920		5,879,691
Obligations Under Capital Leases (a)		12,236		12,873		13,397		14,743		14,425
Income Statement Data:										
Operating Revenues	$	4,898,167	$	5,439,430	$	5,800,095	$	5,822,226	$	6,877,687
Income from Continuing Operations		394,107		335,592		266,387		251,455		138,495
Income from Discontinued Operations		-		-		-		587		337,642
Net Income Attributable to Noncontrolling Interests		6,158		5,559		5,559		5,559		5,559
Net Income Attributable to Controlling Interests	$	387,949	$	330,033	$	260,828	$	246,483	$	470,578
Common Share Data:										
Basic Earnings Per Common Share:										

Income from Continuing Operations	$ 2.20	$ 1.91	$ 1.68	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	-	-	2.20
Net Income Attributable to Controlling Interests	$ 2.20	$ 1.91	$ 1.68	$ 1.59	$ 3.06
Diluted Earnings Per Common Share:					
Income from Continuing Operations	$ 2.19	$ 1.91	$ 1.67	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	-	-	2.19
Net Income Attributable to Controlling Interests	$ 2.19	$ 1.91	$ 1.67	$ 1.59	$ 3.05
Weighted Average Common Shares Outstanding					
Basic	176,636,086	172,567,928	155,531,846	154,759,727	153,767,527
Diluted	176,885,387	172,717,246	155,999,240	155,304,361	154,146,669
Dividends Declared Per Share	$ 1.03	$ 0.95	$ 0.83	$ 0.78	$ 0.73
Market Price - Closing (high) (b)	$ 32.05	$ 26.33	$ 31.15	$ 33.53	$ 28.81
Market Price - Closing (low) (b)	$ 24.78	$ 19.45	$ 19.15	$ 26.93	$ 19.24
Market Price - Closing (end of year) (b)	$ 31.88	$ 25.79	$ 24.06	$ 31.31	$ 28.16
Book Value Per Share (end of year)	$ 21.60	$ 20.37	$ 19.38	$ 18.79	$ 18.14
Tangible Book Value Per Share (end of year) (c)	$ 19.97	$ 18.74	$ 17.54	$ 16.93	$ 16.28
Rate of Return Earned on Average Common Equity (%) (d)	10.7	10.2	8.8	8.6	18.0
Market-to-Book Ratio (end of year) (e)	1.5	1.3	1.2	1.7	1.6
Capitalization:					
Total Equity	44%	44%	41%	44%	48%
Preferred Stock, not subject to mandatory redemption	1	1	2	2	2
Long-Term Debt (a)	55	55	57	54	50
	100%	100%	100%	100%	100%

(a)

Includes portions due within one year, but excludes RRBs for Long-Term Debt.

(b)

Market price information reflects closing prices as reflected by the New York Stock Exchange.

(c)

Common Shareholders' Equity adjusted for goodwill and intangibles divided by total common shares outstanding.

(d)

Net Income divided by the average change in Common Shareholders' Equity.

(e)

The closing market price divided by the book value per share.

See the *Combined Notes to the Consolidated Financial Statements* for a description of any accounting changes materially affecting the comparability of the information reflected in the table above**.**

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 2,999,102	$ 3,424,538	$ 3,558,361	$ 3,681,817	$ 3,979,811
Net Income	244,143	216,316	191,158	133,564	200,007
Cash Dividends on Common Stock	217,691	113,848	106,461	79,181	63,732
Property, Plant and Equipment, Net	5,586,504	5,340,561	5,089,124	4,401,846	3,634,370
Total Assets	8,287,585	8,364,564	8,336,118	7,018,099	6,321,294
Rate Reduction Bonds	-	195,587	378,195	548,686	743,899
Long-Term Debt (a)	2,583,102	2,582,361	2,270,414	2,028,546	1,519,440
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	10,613	10,956	11,207	13,602	14,264

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 1,033,439	$ 1,109,591	$ 1,141,202	$ 1,083,072	$ 1,140,900
Net Income	90,067	65,570	58,067	54,434	35,323
Cash Dividends on Common Stock	50,584	40,844	36,376	30,720	41,741
Property, Plant and Equipment, Net	2,053,281	1,814,714	1,580,985	1,388,405	1,242,378
Total Assets	2,889,840	2,697,191	2,628,833	2,106,969	2,071,276
Rate Reduction Bonds	138,247	188,113	235,139	282,018	333,831
Long-Term Debt (a)	836,365	836,255	686,779	576,997	507,099
Obligations Under Capital Leases (a)	1,428	1,670	1,931	1,141	1,356

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2010	2009	2008	2007	2006
Operating Revenues	$ 395,161	$ 402,413	$ 441,527	$ 464,745	$ 431,509
Net Income	23,090	26,196	18,330	23,604	15,644
Cash Dividends on Common Stock	14,882	18,203	39,706	12,779	7,946
Property, Plant and Equipment, Net	817,146	705,760	624,205	559,357	526,094
Total Assets	1,199,559	1,101,800	1,048,489	991,088	988,693
Rate Reduction Bonds	43,325	58,735	73,176	86,731	99,428
Long-Term Debt (a)	400,288	305,475	303,868	303,872	261,777
Obligations Under Capital Leases (a)	83	105	126	-	-

(a)

Includes portions due within one year, but excludes RRBs for Long-Term Debt.

Item 7.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 to "NU," the "Company," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a diluted basis.

Refer to the Glossary of Terms included in this Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the consolidated financial statements.

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 allocated to 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 or loss attributable to controlling interests of each business by the weighted average diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to provide details of earnings results and guidance by business. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our businesses. This non-GAAP financial measure should not be considered as an alternative to our consolidated diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes non-GAAP financial measures referencing our 2010 earnings and EPS excluding expenses related to NU's proposed merger with NSTAR and certain non-recurring benefits from the settlement of tax issues as well as our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation. We use these non-GAAP financial measures to more fully compare and explain the 2010, 2009 and 2008 results without including the impact of these non-recurring items. Due to the nature and significance of these items on Net Income, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to readers of this report in analyzing historical and future performance. These non-GAAP financial measures should not be considered as alternatives to reported Net Income Attributable to Controlling Interests or EPS determined in accordance with GAAP as indicators 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 Interests are included under "Financial Condition and Business Analysis-Overview-Consolidated" and "Financial Condition and Business Analysis-Future Outlook" in *Management's Discussion and Analysis*, herein. All forward-looking information for 2011 and thereafter provided in this *Management s Discussion and Analysis* assumes we will operate on a stand-alone basis, excluding the impacts of the proposed merger with NSTAR, unless otherwise indicated.

Financial Condition and Business Analysis

Proposed Merger with NSTAR:

On October 18, 2010, we and NSTAR announced that each company's Board of Trustees unanimously approved a Merger Agreement (the "agreement") to create a combined company that will be called Northeast Utilities. The transaction was structured as a merger of equals in a tax-free exchange. The post-transaction company will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England.

Under the terms of the agreement, NSTAR shareholders would receive 1.312 NU common shares for each NSTAR common share that they own (the "exchange ratio"). The exchange ratio was structured to result in a no premium merger based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Based on the number of NU common shares and NSTAR common shares estimated to be outstanding immediately prior to the closing of the merger, upon such closing, NU shareholders will own approximately 56 percent of the post-transaction company and former NSTAR shareholders will own approximately 44 percent of the post-transaction company. It is anticipated that we would issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger.

Subject to the conditions in the agreement, our first quarterly dividend per common share declared after the completion of the merger will be increased to an amount that is equivalent, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. Based on the last quarterly dividend paid by NSTAR, and assuming there are no changes to such dividend prior to the closing of the merger, this anticipated amount would be approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

Completion of the merger is subject to various customary conditions, including, among others, approval by holders of two-thirds of the outstanding common shares of each company and receipt of all required regulatory approvals. The companies anticipate that the regulatory approvals can be obtained to permit the merger to close in the second half of 2011. Special meetings of shareholders of both companies to approve the merger are scheduled for March 4, 2011. On November 24, 2010, NU and NSTAR filed a joint petition requesting Massachusetts DPU approval of their proposed merger by May 15, 2011. On January 5, 2011, a public hearing and procedural conference were held before the DPU. The schedule has subsequently been suspended pending a decision on the appropriate standard of review for the merger. On January 4, 2011, we received approval from the FCC, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. On January 7, 2011, NU and NSTAR filed an application with the FERC, requesting approval of the merger by May 10, 2011.

In November 2010, the DPUC issued a draft decision stating that it lacked jurisdiction over the merger. In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC to reconsider its draft decision. In January 2011, the DPUC issued an Administrative Order stating that it plans to hold a hearing to determine if it has jurisdiction over the merger. Oral arguments surrounding the draft decision were held in February 2011. The DPUC plans to hold an informational hearing at a date to be determined. In addition, legislation proposing to give the DPUC jurisdiction over the merger may be introduced in the Connecticut legislature.

Executive Summary

The following items in this executive summary are explained in more detail in this Annual Report:

Results:

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We earned $387.9 million, or $2.19 per share, in 2010, compared with $330 million, or $1.91 per share, in 2009. Improved results were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010, higher retail electric sales due to weather impacts, the non-recurring benefits from the settlement of tax issues in the fourth quarter of 2010, and our continued success in managing operation and maintenance costs. These benefits were partially offset by higher pension and storm-related expenses and expenses related to our proposed merger with NSTAR.

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Our Regulated companies earned $384 million, or $2.16 per share, in 2010, compared with $323.5 million, or $1.87 per share, in 2009.

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Earnings from the distribution segment of our Regulated companies (which also includes the generation businesses of PSNH and WMECO and the natural gas distribution business of Yankee Gas) totaled $206.2 million, or $1.16 per share, in 2010, compared with $159.2 million, or $0.92 per share, in 2009. Earnings from the transmission segment of our Regulated companies totaled $177.8 million, or $1.00 per share, in 2010, compared with $164.3 million, or $0.95 per share, in 2009.

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Our competitive businesses, which are held by NU Enterprises, earned $8.3 million, or $0.05 per share, in 2010, compared with $15.8 million, or $0.09 per share, in 2009. NU Enterprises recorded $0.7 million of after-tax mark-to-market gains in 2010, compared with $3.8 million of after-tax mark-to-market gains in 2009.

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NU parent and other companies recorded net expenses of $4.4 million, or $0.02 per share, in 2010, compared with net expenses of $9.3 million, or $0.05 per share, in 2009. The 2010 results include a fourth quarter non-recurring benefit of $15.7 million, or $0.09 per share, associated with the settlement of tax issues and a fourth quarter after-tax charge of $9.4 million, or $0.06 per share, associated with expenses related to NU s proposed merger with NSTAR.

Outlook:

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Excluding certain non-recurring costs related to our proposed merger with NSTAR of approximately $0.15 per share, we project consolidated 2011 earnings of between $2.25 per share and $2.40 per share. This projection includes distribution segment earnings of between $1.25 per share and $1.35 per share, transmission segment earnings of between $1.05 per share and $1.10 per share, and net expenses at NU parent and other companies of approximately $0.05 per share, excluding merger-related costs of approximately $0.15 per share. The number of outstanding NU common shares used to calculate this guidance is approximately 177 million shares. Results from our competitive businesses are factored into the NU parent and other companies results. This projection assumes we will operate on a stand-alone basis in 2011, although our proposed merger with NSTAR is expected to close in the second half of 2011.

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We project a compound average annual EPS growth rate through 2015 of between 6 percent and 9 percent using 2009 EPS of $1.91 per share as the base level. Assuming completion of our proposed merger with NSTAR, we expect our EPS growth rate will be at the higher end of this range.

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We project capital expenditures for 2011 through 2015 of approximately $6.6 billion (approximately $1.2 billion in 2011). During that time period, we expect our Regulated company rate base to increase from approximately $7.3 billion at the end of 2010 to approximately $11.4 billion at the end of 2015, excluding any impacts from the merger.

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On February 8, 2011, our Board of Trustees declared a quarterly common dividend of $0.275 per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011, which equates to $1.10 per share on an annualized basis. Assuming completion of our proposed merger with NSTAR, based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, our first quarterly dividend per common share declared would be approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

Strategy, Regulatory and Other Items:

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On June 30, 2010, the DPUC issued a final decision in CL&P's distribution rate case that approved annualized rate increases of $63.4 million effective July 1, 2010 and an additional $38.5 million effective July 1, 2011. The decision approved CL&P s proposal to defer implementation of the first increase by six months until January 1, 2011 and maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent.

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On June 28, 2010, the NHPUC approved the distribution rate case settlement agreement among PSNH, the NHPUC staff and the Office of Consumer Advocate. Under the agreement, the settling parties agreed to a net annualized distribution rate increase of $45.5 million, effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years. PSNH s authorized distribution business regulatory ROE remained at 9.67 percent.

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On January 31, 2011, the DPU issued a final decision in WMECO's distribution rate case that approved an annualized rate increase of $16.8 million effective February 1, 2011 and an authorized distribution segment regulatory ROE of 9.6 percent.

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On January 7, 2011, Yankee Gas filed an application with the DPUC to increase distribution rates by $32.8 million effective July 1, 2011 and by an additional $13 million effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized regulatory ROE of 10.1 percent. A final decision is expected in June 2011.

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On February 11, 2011, the FERC accepted without modification the TSA that NPT and Hydro Renewable Energy entered into in connection with the Northern Pass transmission project. Assuming timely receipt of other regulatory reviews and siting approvals, NPT expects to place the project in service in late 2015.

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CL&P and WMECO have received siting approvals in Connecticut and Massachusetts, respectively, for the first and largest component of our NEEWS project, GSRP, which involves the construction of 115 KV and 345 KV lines from Ludlow, Massachusetts, to Bloomfield, Connecticut. We commenced substation construction in December 2010, and expect to begin overhead line construction in the first half of 2011. We expect the cost of this project to be $795 million and to place the project in service in late 2013.

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Construction of PSNH s Clean Air Project at Merrimack Station was approximately 80 percent complete as of December 31, 2010 and is projected to cost approximately $430 million, which is approximately $27 million below the project s previously announced cost of $457 million. The project must be operational by July 1, 2013, but PSNH expects it will commence operations by mid-2012.

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On December 17, 2010, President Obama signed into law the 2010 Tax Act. We expect the 2010 Tax Act to provide NU with cash flow benefits of approximately $250 million in 2011 and approximately $450 million to $550 million over the period 2011 through 2013.

Liquidity:

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Cash capital expenditures totaled $954.5 million in 2010, compared with $908.1 million in 2009.

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Cash flows provided by operating activities in 2010 totaled $832.6 million, compared with $745 million in 2009 (amounts are net of RRB payments). The improved cash flows were due primarily to the absence in 2010 of costs incurred at PSNH and WMECO related to the major storm in December 2008 that were paid in the first quarter of 2009, a decrease in Fuel, Materials and Supplies attributable to a $31.8 million reduction in coal inventory levels at PSNH, and increases in amortization on regulatory deferrals within PSNH s ES and CL&P s CTA tracking mechanisms. Offsetting these favorable cash flow impacts was a $–––45 million contribution to our Pension Plan. Excluding the impact of our proposed merger with NSTAR, we project 2011 cash flows provided by operating activities, net of RRB payments, of approximately $950 million to $1 billion. The increase over 2010 is due primarily to the accelerated depreciation provisions of the 2010 Tax Act and the impact of the 2010 distribution rate case decisions. Those benefits are partially offset by projected 2011 contributions to our Pension Plan of approximately $145 million.

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Cash and cash equivalents totaled $23.4 million as of December 31, 2010, compared with $27 million as of December 31, 2009.

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On September 24, 2010, CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, replacing a five-year $400 million credit facility that was scheduled to expire on November 6, 2010. On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, replacing a five-year $500 million credit facility that was scheduled to expire on November 6, 2010. Both new revolving credit facilities expire on September 24, 2013. As of December 31, 2010, we had $600.9 million of aggregate borrowing availability on our revolving credit lines, as compared to $702.8 million as of December 31, 2009.

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We issued $145 million of new long-term debt in 2010, consisting of $95 million by WMECO and $50 million by Yankee Gas. Additionally, CL&P remarketed $62 million of tax-exempt PCRBs. In 2011, in addition to remarketing the CL&P $62 million PCRBs, we expect to issue approximately $260 million of long-term debt comprised of $160 million by PSNH and $100 million by WMECO in the second half of 2011. We have no debt maturities until April 2012.

Overview

Consolidated: We earned $387.9 million, or $2.19 per share, in 2010, compared with $330 million, or $1.91 per share, in 2009 and $260.8 million, or $1.67 per share, in 2008. Improved results were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010, higher retail electric sales due to warmer than normal summer weather and colder than normal December 2010 weather, the non-recurring benefits from the settlement of tax issues in the fourth quarter of 2010, lower uncollectibles expense, our continued success in managing operation and maintenance costs, and increased earnings in the transmission segment. These benefits were partially offset by higher pension and storm-related expenses, expenses related to our proposed merger with NSTAR, charges associated with the enactment of the 2010 Healthcare Act, and lower earnings at our competitive businesses. Due primarily to weather impacts, retail electric sales were up 1.7 percent in 2010 compared with 2009.

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 Interests and diluted EPS, for 2010, 2009 and 2008 is as follows:

	For the Years Ended December 31,					
	2010		**2009**		**2008**	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interests (GAAP)	$ 387.9	$ 2.19	$ 330.0	$ 1.91	$ 260.8	$ 1.67
Regulated Companies	$ 384.0	$ 2.16	$ 323.5	$ 1.87	$ 289.1	$ 1.85
Competitive Businesses	8.3	0.05	15.8	0.09	13.1	0.08
NU Parent and Other Companies	(10.7)	(0.05)	(9.3)	(0.05)	(11.6)	(0.07)
Non-GAAP Earnings	381.6	2.16	330.0	1.91	290.6	1.86
Non-Recurring Tax Settlements	15.7	0.09	-	-	-	-
Merger-Related Costs (after-tax)	(9.4)	(0.06)	-	-	-	-
Litigation Charge (after-tax)	-	-	-	-	(29.8)	(0.19)
Net Income Attributable to Controlling Interests (GAAP)	$ 387.9	$ 2.19	$ 330.0	$ 1.91	$ 260.8	$ 1.67

Regulated Companies: Our Regulated companies consist of the distribution and electric transmission segments, with Yankee Gas natural gas distribution segment and PSNH and WMECO generation activities included in the distribution segment. A summary of our Regulated companies' earnings by segment for 2010, 2009 and 2008 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2010**	**2009**	**2008**

CL&P Transmission	$	143.9	$	136.8	$	115.6
PSNH Transmission		20.7		18.0		16.7
WMECO Transmission		13.0		9.5		6.0
NUTV		0.2		-		-
Total Transmission	$	177.8	$	164.3	$	138.3
CL&P Distribution	$	94.1	$	74.0	$	70.0
PSNH Distribution		69.3		47.5		41.4
WMECO Distribution		10.1		16.7		12.3
Yankee Gas		32.7		21.0		27.1
Total Distribution	$	206.2	$	159.2	$	150.8
Net Income - Regulated Companies	$	384.0	$	323.5	$	289.1

The higher 2010 and 2009 transmission segment earnings reflect increasing investment in transmission infrastructure to meet the reliability needs of our customers and the region. Our transmission rate base totaled $2.76 billion at the end of 2010, compared with $2.6 billion at the end of 2009.

CL&P s 2010 distribution segment earnings were $20.1 million higher than 2009 due primarily to the DPUC distribution rate case decision that was effective July 1, 2010. The decision allowed CL&P to defer operating and maintenance expenses for the last six months of 2010 in lieu of cash rate relief until new rates begin on January 1, 2011. CL&P s 2010 earnings also benefitted from lower depreciation expense as authorized in the distribution rate case decision, lower interest expense as a result of the favorable resolution of state tax audits in the fourth quarter of 2010, and lower uncollectibles expenses. Partially offsetting these favorable items were higher storm restoration costs and higher pension costs. CL&P s 2010 retail electric sales were 1.8 percent higher than 2009 due primarily to warmer than normal weather during the summer of 2010. CL&P s distribution segment regulatory ROE was 7.9 percent in 2010 compared to 7.3 percent in 2009. We expect CL&P s distribution segment regulatory ROE will be approximately 9 percent in 2011.

PSNH s 2010 distribution segment earnings were $21.8 million higher than 2009. The improved performance in 2010 was due primarily to higher revenues as a result of distribution rate increases effective August 1, 2009 and July 1, 2010, higher AFUDC earnings related to the Clean Air Project capital expenditures, and higher retail electric sales of 1.3 percent due primarily to warmer than normal weather during the summer of 2010. The permanent distribution rate case settlement approved on June 28, 2010 allowed for certain costs to be recovered retroactive to August 1, 2009. These favorable items were partially offset by higher expenses, including employee benefit costs, storm restoration costs, depreciation, interest expense and income taxes as a result of a higher effective tax rate in 2010. PSNH s distribution segment regulatory ROE was 10.2 percent (including generation) in 2010, compared to 7.2 percent in 2009. We expect PSNH s distribution segment regulatory ROE will be approximately 9 percent in 2011.

WMECO s 2010 distribution segment earnings were $6.6 million lower than 2009 due primarily to higher operating costs including storm restoration costs, employee benefit costs, depreciation and property taxes as well as a net $2.1 million after-tax charge primarily related to uncollectibles expense as a result of the outcome of the distribution rate case decision from the DPU on January 31, 2011. These

29

unfavorable items were partially offset by stronger retail distribution revenues. WMECO s 2010 retail electric sales were 2.4 percent higher than 2009 due primarily to warmer than normal weather during the summer of 2010. WMECO s distribution segment regulatory ROE was 4.6 percent in 2010 compared to 8.4 percent in 2009. On January 31, 2011, the DPU authorized a distribution segment regulatory ROE of 9.6 percent as part of its distribution rate case decision. We expect WMECO s distribution segment regulatory ROE will be approximately 9 percent in 2011.

Yankee Gas 2010 earnings were $11.7 million higher than 2009 due primarily to lower uncollectibles expenses, higher revenues attributable to a 1.9 percent increase in firm sales as compared to 2009, and lower depreciation expense. Partially offsetting these favorable items were higher employee benefit costs. Yankee Gas regulatory ROE was 8.6 percent in 2010 compared to 6.6 percent in 2009. In June 2011 we anticipate the DPUC will issue a decision on Yankee Gas request to raise its distribution rates effective July 1, 2011. Yankee Gas request includes a recommendation to maintain its authorized regulatory ROE of 10.1 percent.

For the distribution segment of our Regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric GWh sales and Yankee Gas firm natural gas sales for 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Electric								
	CL&P		PSNH		WMECO		Total		
	Percentage Increase	Weather Normalized Percentage Decrease	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Decrease	Pe In (D
Residential	3.5%	(1.0)%	2.5%	(0.5)%	5.1%	1.4%	3.5%	(0.7)%	
Commercial	0.1%	(3.0)%	(0.1)%	(3.0)%	1.5%	(1.4)%	0.2%	(2.8)%	
Industrial	1.7%	(1.0)%	1.6%	(1.9)%	(0.6)%	(2.4)%	1.3%	(1.5)%	
Other	-	-	0.4%	0.4%	(19.9)%	(19.9)%	(1.4)%	(1.4)%	
Total	1.8%	(1.8)%	1.3%	(1.8)%	2.4%	(0.6)%	1.7%	(1.7)%	

A summary of our retail electric sales in GWh for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for 2010 and 2009 is as follows:

	Electric			Firm Natural Gas		
	2010	2009	Percentage Increase/ (Decrease)	2010	2009	Percentage Increase/ (Decrease)
Residential	14,913	14,412	3.5%	13,403	13,562	(1.2)%
Commercial	14,506	14,474	0.2%	14,982	14,063	6.6 %
Industrial	4,481	4,423	1.3%	14,866	14,825	0.3 %
Other	330	336	(1.4)%	-	-	-

Total	34,230	33,645	1.7%	43,251	42,450	1.9 %

Actual retail electric sales for all three electric companies were higher in 2010 compared to 2009 due primarily to warmer than normal summer weather and colder than normal weather in December 2010. Residential sales benefitted the most from the favorable impacts of the weather in 2010 and were higher for all three electric companies in 2010 compared to 2009. Cooling degree days in 2010 for Connecticut and Western Massachusetts were 77 percent higher than 2009 and 41 percent above normal. In New Hampshire, cooling degree days in 2010 were 107 percent higher than 2009 and 42 percent above normal.

On a weather normalized basis, retail electric sales for all three electric companies were lower in 2010 compared to 2009. We believe the decrease in weather normalized residential sales was due in part to increased conservation efforts by our customers and continuing effects of the weak economy on our customers. The decline in commercial sales in 2010 compared to 2009 can be attributed in part to relatively weak employment growth, higher vacancy rates and uncertainty in consumer confidence. Industrial sales were also lower in 2010 compared to 2009 due to a lack of manufacturing sector hiring although industrial sales benefitted from increased manufacturing hours worked. Our commercial and industrial sales continue to be negatively impacted by additional installation of gas-fired distributed generation and utilization of C&LM programs.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from a favorable price for natural gas and the addition of gas-fired distributed generation in Yankee Gas service territory. Actual firm natural gas sales in 2010 were higher than 2009 despite the milder weather during the first quarter 2010 heating season. Heating degree days in 2010 for Connecticut were 11 percent below 2009 levels and 11 percent below normal levels. Firm natural gas sales benefitted from commercial and industrial customers switching from interruptible service to firm service, additional gas-fired distributed generation, and a large commercial customer who began to take service from Yankee Gas mid-way through the third quarter of 2009 and continued to take service throughout all of 2010.

Our expense related to uncollectible receivable balances (our uncollectibles expense) is influenced by the economic conditions of our region. Fluctuations in our uncollectibles expense are mitigated from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated for recovery to the respective company's energy supply rate and recovered through its tariffs. Additionally, for CL&P and Yankee Gas, write-offs of uncollectible receivable balances attributable to qualified customers under financial or medical duress (hardship customers) are fully recovered through their respective tariffs. In 2010, our total pre-tax uncollectibles expense that impacts earnings was $23.4 million as compared to $46.5 million in 2009.

The improvement in 2010 uncollectibles expense was due in part to continued accounts receivable collection efforts and we expect our 2011 uncollectibles expense to be consistent with 2010.

Competitive Businesses: NU Enterprises, which continues to manage to completion Select Energy's remaining wholesale marketing contracts and to manage its electrical contracting business and other operating and maintenance services contracts, earned $8.3 million, or $0.05 per share, in 2010, compared with $15.8 million, or $0.09 per share, in 2009 and $13.1 million, or $0.08 per share, in 2008. In 2010, NU Enterprises recorded $0.7 million of after-tax mark-to-market gains, compared with after-tax mark-to-market gains of $3.8 million in 2009 and $1.1 million in 2008.

NU Parent and Other Companies: NU parent and other companies recorded net expenses of $4.4 million, or $0.02 per share, in 2010, compared with net expenses of $9.3 million, or $0.05 per share, in 2009 and net expenses of $41.4 million, or $0.26 per share, in 2008. The 2010 results include a fourth quarter non-recurring benefit of $15.7 million, or $0.09 per share, associated with the settlement of tax issues and a fourth quarter after-tax charge of $9.4 million, or $0.06 per share, associated with expenses related to NU s proposed merger with NSTAR. Excluding these impacts, 2010 net expenses increased by $1.4 million as compared to 2009 due primarily to a $0.9 million after-tax unfavorable change in the HWP environmental reserve and a $0.6 million net after-tax charge associated with the 2010 Healthcare Act, partially offset by lower interest expense at NU parent. The net expenses in 2008 included a $29.8 million, or $0.19 per share, after-tax charge resulting from the payment of $49.5 million made in March 2008 associated with the settlement of litigation.

Future Outlook

EPS Guidance: Following is a summary of our projected 2011 EPS by business, which also reconciles consolidated diluted EPS to the non-GAAP financial measure of EPS by business. Non-GAAP EPS by business also excludes a $0.15 per share charge related to expected non-recurring merger costs we will incur relating to financial advisor costs, legal, accounting and consulting fees, which will affect NU parent and other companies' results.

	2011 EPS Range			
(Approximate amounts)		**Low**		**High**
Diluted EPS (GAAP)	$	2.10	$	2.25
Regulated Companies:				
Distribution Segment	$	1.25	$	1.35
Transmission Segment		1.05		1.10
Total Regulated Companies		2.30		2.45
NU Parent and Other Companies		(0.05)		(0.05)
Non-GAAP EPS	$	2.25	$	2.40
Merger-Related Costs		(0.15)		(0.15)
Diluted EPS (GAAP)	$	2.10	$	2.25

This projection assumes we will operate on a stand-alone basis in 2011, although our proposed merger with NSTAR is expected to close in the second half of 2011. We have included the impacts of the CL&P, PSNH, and WMECO electric distribution rate case decisions received as well as an anticipated reasonable outcome in the Yankee Gas rate case decision expected in June 2011 in the assumptions used to develop our 2011 earnings guidance. The 2011 distribution and transmission earnings guidance reflects the impact of a higher rate base as well as $1.2 billion of projected capital expenditures in 2011. The 2011 distribution segment earnings guidance assumes that total weather-normalized retail electric sales are essentially unchanged from 2010 and weather-normalized firm natural gas sales, excluding special contracts as fluctuations in their usage do not impact earnings, are approximately 4 percent higher than 2010. Offsetting these favorable items are assumed increases in pension costs and certain operation and maintenance costs.

In 2010, the NU effective tax rate was 34.8 percent. For 2011, we estimate that the effective tax rate for NU will be approximately 35 percent.

Long-Term Growth Rate: We project that we will achieve a compound average annual EPS growth rate for the five-year period from 2011 to 2015 of between 6 percent and 9 percent using 2009 EPS of $1.91 per share as the base level. Assuming completion of our proposed merger with NSTAR in the second half of 2011, we expect to achieve an EPS growth rate at the higher end of the range of 6 percent and 9 percent.

Liquidity

Consolidated: Cash and cash equivalents totaled $23.4 million as of December 31, 2010, compared with $27 million as of December 31, 2009.

NU subsidiaries issued a total of $145 million in long-term debt in 2010. On March 8, 2010, WMECO issued $95 million of senior unsecured notes due March 1, 2020 carrying a coupon rate of 5.1 percent. On April 22, 2010, Yankee Gas issued $50 million of first mortgage bonds through a private placement with a maturity date of April 1, 2020 carrying a coupon rate of 4.87 percent. The proceeds from these financings were used to repay short-term borrowings incurred in the ordinary course of business and to fund ongoing capital investment programs.

On April 1, 2010, CL&P remarketed $62 million of tax-exempt PCRBs that were subject to a mandatory tender on April 1, 2010. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.4 percent for a one-year period and are subject to a mandatory tender for purchase on April 1, 2011, at which time CL&P expects to remarket them.

On November 1, 2010, the DPUC approved CL&P's application requesting authority to issue up to $900 million in long-term debt through 2014. Proceeds will be used to refinance CL&P's short-term debt previously incurred in the ordinary course of business, to finance capital expenditures, to provide working capital and to pay issuance costs.

On November 10, 2010, the DPUC approved Yankee Gas application to issue up to $300 million in long-term debt through 2014. Proceeds will be used to refinance Yankee Gas short-term debt previously incurred in the ordinary course of business, to refinance its Series G first mortgage bonds due in 2014, to finance capital expenditures, to provide working capital and to pay issuance costs.

On November 12, 2010, PSNH filed an application with the NHPUC requesting authority to issue securities for the purpose of refinancing certain series of PCRBs totaling $209 million. A public hearing for this application was held February 4, 2011 and a decision is pending.

On December 17, 2010, the NHPUC authorized PSNH to issue up to $160 million of long-term debt through 2011. Proceeds will be used to refinance PSNH's short-term debt previously incurred in the ordinary course of business, to finance capital expenditures, to provide working capital and to pay issuance costs.

On January 28, 2011, the DPU authorized WMECO to issue up to $330 million in long-term debt through December 31, 2012 to be used to refinance WMECO s short-term debt previously incurred in the ordinary course of business, to finance capital expenditures, to provide working capital and to pay issuance costs.

On September 24, 2010, CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, which expires on September 24, 2013. This facility replaced a five-year $400 million credit facility on similar terms and conditions that was scheduled to expire on November 6, 2010. CL&P and PSNH are each able to draw up to $300 million under this facility, and WMECO and Yankee Gas are each able to draw up to $200 million, subject to the $400 million maximum aggregate borrowing limit. This total commitment may be increased to $500 million at the request of the borrowers, subject to lender approval. Under this facility, each company can borrow either on a short-term or a long-term basis, subject to regulatory approval. As of December 31, 2010, PSNH had $30 million of short-term borrowings outstanding under this facility, leaving $370 million of aggregate borrowing capacity available. The weighted-average interest rate on these short-term borrowings as of December 31, 2010 was 2.05 percent, which is based on a variable rate plus an applicable margin based on PSNH's credit ratings.

On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, which expires on September 24, 2013. This facility replaced a five-year $500 million credit facility on similar terms and conditions that was scheduled to expire on November 6, 2010. Like the previous facility, the new revolving credit facility allows NU parent to borrow up to $500 million at any one time on a short-term or long-term basis and allows for the issuance of LOCs up to $500 million in the aggregate (net of the amount of borrowings then outstanding) on behalf of NU or any of its subsidiaries for periods up to 364 days. This total commitment may be increased to $600 million at the request of NU parent, subject to lender approval. As of December 31, 2010, NU parent had $32.1 million of LOCs issued primarily for the benefit of PSNH and $237 million of short-term borrowings outstanding, leaving $230.9 million of borrowing capacity available. The weighted-average interest rate on these short-term borrowings as of December 31, 2010 was 2.85 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings.

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH and WMECO, comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to total capitalization ratio. As of December 31, 2010, all such companies were in compliance with these covenants. Refer to Note 8, "Short-Term Debt," and Note 9, "Long-Term Debt," to our consolidated financial statements included in this Annual Report on Form 10-K for further discussion of material terms and conditions of these agreements.

In 2011, in addition to remarketing the CL&P $62 million PCRBs, we expect to issue approximately $260 million of long-term debt comprised of $160 million by PSNH and $100 million by WMECO in the second half of 2011. We have annual sinking fund requirements of $4.3 million continuing in 2011 through 2012, the mandatory tender of $62 million of tax-exempt PCRBs by CL&P on April 1, 2011, at which time CL&P expects to remarket the bonds in the ordinary course, and no debt maturities until April 1, 2012. In light of the 2010 Tax Act and the related cash flow benefits, we are currently reevaluating the timing of our previously planned NU common equity issuance. If we complete the proposed merger with NSTAR, we would no longer need to undertake the previously planned $300 million NU common equity issuance in 2012 nor issue any additional equity in the foreseeable future.

Cash flows provided by operating activities in 2010 totaled $832.6 million, compared with operating cash flows of $745 million in 2009 and $424.1 million in 2008 (all amounts are net of RRB payments, which are included in financing activities on the accompanying consolidated statements of cash flows). The improved cash flows were due primarily to the absence in 2010 of costs incurred at PSNH and WMECO related to the major storm in December 2008 that were paid in the first quarter of 2009, a decrease in Fuel, Materials and Supplies attributable to a $31.8 million reduction in coal inventory levels at the PSNH generation business as ordered by the NHPUC, and increases in amortization on regulatory deferrals primarily attributable to 2009 activity within PSNH s ES and CL&P s CTA tracking mechanisms where such costs exceeded revenues resulting in an unfavorable cash flow impact in 2009. Offsetting these favorable cash flow impacts was a $–––45 million contribution made into our Pension Plan in September 2010. The increase in operating cash flows from 2008 to 2009 was due primarily to higher transmission revenues at CL&P after significant projects were placed in service in late 2008, as well as cost management efforts; a decrease of approximately $225 million related primarily to amounts spent on CL&P's

FMCC and GSC, the costs of which are passed on to customers; approximately $100 million less in cash expenditures on Fuel, Materials and Supplies in 2009 due primarily to the lower cost of natural gas being stored by Yankee Gas for the winter heating season; and the absence in 2009 of the litigation settlement payment of $49.5 million made in 2008.

Excluding the impact of our proposed merger with NSTAR, we project 2011 cash flows provided by operating activities of approximately $950 million to $1 billion, net of RRB payments. The increase over 2010 is due primarily to the accelerated depreciation provisions of the 2010 Tax Act, which is expected to result in a cash flow benefit of approximately $250 million in 2011, and the impact of the 2010 distribution rate case decisions. Those benefits are partially offset by projected 2011 contributions to our Pension Plan of approximately $145 million.

On December 30, 2010, CL&P made its final principal and interest payment on approximately $1.4 billion of RRBs that were issued in 2001. As a result, CL&P will no longer recover any payments from customers associated with these RRBs. A total of $203.2 million of principal and interest payments were made on these RRBs in 2010. The full amortization of these RRBs in 2010 will reduce CL&P s cash flows provided by operating activities in 2011, compared with previous years, but will have no material impact on CL&P s operating cash flows net of RRB payments. PSNH and WMECO RRBs do not fully amortize until 2013, therefore the RRBs do not have an impact on their respective operating cash flows in 2011 when compared to 2010.

A summary of the current credit ratings and outlooks by Moody's, S&P and Fitch for senior unsecured debt of NU parent 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	Baa2	Stable	BBB-	Watch-Positive	BBB	Watch-Positive
CL&P	A2	Stable	BBB+	Watch-Positive	A-	Stable
PSNH	A3	Stable	BBB+	Watch-Positive	BBB+	Stable
WMECO	Baa2	Stable	BBB	Watch-Positive	BBB+	Stable

On October 18, 2010, following the announcement of the proposed merger of NU and NSTAR, Moody's announced that it had reaffirmed the ratings and "stable" outlooks of NU parent, CL&P, PSNH and WMECO, and S&P announced that it had placed NU parent, CL&P, PSNH and WMECO's ratings outlooks on credit watch with "positive" implications. On October 19, 2010, also due to the announcement of the proposed merger, Fitch announced that it had reaffirmed the ratings and "stable" outlooks of CL&P, PSNH and WMECO and placed NU parent's ratings outlook on credit watch with "positive" implications. Assuming completion of the proposed merger with NSTAR, we expect our credit ratings will improve.

On January 22, 2010, Fitch downgraded CL&P s preferred stock rating from BBB to BBB- as a result of revised guidelines for rating preferred stock and hybrid securities in general.

If the senior unsecured debt ratings of NU parent were to be reduced to below investment grade level by either Moody's or S&P, a number of Select Energy's supply contracts would require Select Energy to post additional collateral in the form of cash or LOCs. If such an event had occurred as of December 31, 2010, Select Energy would have been required to provide additional cash or LOCs in an aggregate amount of $24 million to various unaffiliated counterparties and additional cash or LOCs in the aggregate amount of $7.4 million to independent system operators. NU parent would have been and remains able to provide that collateral on behalf of Select Energy.

If the unsecured debt ratings of PSNH were to be reduced by either Moody's or S&P, certain supply contracts could require PSNH to post additional collateral in the form of cash or LOCs with various unaffiliated counterparties. As of December 31, 2010, if the unsecured debt ratings of PSNH had been reduced by one level or to below investment grade, PSNH had an adequate amount of collateral posted and would not have been required to post additional amounts.

We paid common dividends of $180.5 million in 2010, compared with $162.4 million in 2009 and $129.1 million in 2008. The increase reflects a 7.9 percent increase in our common dividend rate that took effect in the first quarter of 2010, as well as a higher number of shares outstanding as a result of the March 2009 issuance of nearly 19 million common shares. On February 8, 2011, our Board of Trustees declared a quarterly common dividend of $0.275 per share, payable on March 31, 2011 to shareholders of record as of March 1, 2011, which equates to $1.10 per share dividend on an annualized basis. This increase represented an approximately 7.3 percent increase over the previous dividend rate.

Assuming completion of our proposed merger with NSTAR and subject to the conditions in the merger agreement, our first quarterly dividend per common share declared after the completion of the proposed merger will be increased to an amount that is equivalent, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing. Based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, that would result in NU s quarterly dividend being increased by approximately 18 percent to approximately $0.325 per share, or approximately $1.30 per share on an annualized basis.

Our ability to pay common dividends is subject to approval by our Board of Trustees and our future earnings and cash flow requirements and may be limited by state statute, the leverage restrictions in our revolving credit agreement and the ability of our subsidiaries to pay common dividends to NU parent. The Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances unless a higher amount is approved by FERC; PSNH is required to reserve an additional amount of retained earnings under its FERC hydroelectric license conditions. In addition, relevant state statutes may impose

additional limitations on the payment of dividends by the Regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions. We do not expect the restrictions to prevent NU from meeting its obligations under the merger agreement.

In general, the Regulated companies pay approximately 60 percent of their earnings to NU parent in the form of common dividends. In 2010, CL&P, PSNH, WMECO, and Yankee Gas paid $217.7 million, $50.6 million, $14.9 million, and $18.8 million, respectively, in common dividends to NU parent. In 2010, NU parent made equity contributions to CL&P, PSNH and WMECO of $2.5 million, $159 million and $102.5 million, respectively.

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in this "Liquidity" section 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 and PBOP expense or income. A summary of our cash capital expenditures by company for the years ended December 31, 2010, 2009 and 2008 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)		**2010**		**2009**		**2008**
CL&P	$	380.3	$	435.7	$	849.5
PSNH		296.3		266.4		238.9
WMECO		115.2		105.4		78.3
Yankee Gas		82.5		54.8		58.3
NPT		7.5		-		-
Other		72.7		45.8		30.4
Total	$	954.5	$	908.1	$	1,255.4

The increase in our cash capital expenditures was the result of higher distribution segment capital expenditures of $66.3 million, particularly at PSNH and Yankee Gas, and an increase in Other of $26.9 million primarily related to technology and facility projects at NUSCO, one of our corporate service companies. These increases were offset by a $46.8 million decrease in transmission segment capital expenditures primarily by CL&P.

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 and PBOP expense or income (all of which are non-cash factors), totaled $1 billion in 2010, $969.2 million in 2009 and $1.3 billion in 2008. These amounts included $68.7 million in 2010, $52.7 million in 2009 and $33.2 million in 2008 related to our corporate service companies, NUSCO and RRR.

Regulated Companies: Capital expenditures for the Regulated companies totaled $967 million ($412.6 million for CL&P, $310 million for PSNH, and $138.4 million for WMECO) in 2010.

Transmission Segment: Transmission segment capital expenditures decreased by $30.9 million in 2010, as compared with 2009, due primarily to reductions in expenditures at CL&P and PSNH, partially offset by increases at WMECO and capital expenditures incurred by NPT for the Northern Pass project. A summary of transmission segment capital expenditures by company in 2010, 2009 and 2008 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2010**	**2009**	**2008**
CL&P	$ 107.2	$ 163.0	$ 586.3
PSNH	49.1	59.4	81.9
WMECO	95.2	67.7	46.1
NPT	9.4	1.7	-
Total	$ 260.9	$ 291.8	$ 714.3

CL&P and WMECO have received siting approvals in Connecticut and Massachusetts, respectively, for the first and largest component of our NEEWS project, GSRP, which involves the construction of 115 KV and 345 KV lines from Ludlow, Massachusetts, to Bloomfield, Connecticut. We commenced substation construction in December 2010 and expect to begin overhead line construction in the first half of 2011. We expect the cost of GSRP to be $795 million and to place the project in service in late 2013. In June 2010, residents living near the proposed Connecticut route of the GSRP appealed the CSC approval in New Britain Superior Court, claiming that the CSC acted improperly by approving an overhead route for the line. We do not expect the appeal to have a material impact on the timing of construction.

Our second major NEEWS project is the Interstate Reliability Project, which is being designed and built in coordination with National Grid USA. CL&P's share of this project includes an approximately 40-mile, 345 KV all overhead line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid USA is designing in Rhode Island and Massachusetts. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project, which is now expected to be placed in service in late 2015. This in-service date assumes that siting applications are filed in all three states in late 2011, with orders received in mid/late 2013 and construction commencing in late 2013 or early 2014. We expect CL&P's share of the costs of this project to be $301 million.

The third major part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide another 345 KV all overhead connection to move power across the state of Connecticut. The timing of this project is expected to be twelve months behind the Interstate Reliability Project. We expect the cost of this project to be $338 million. ISO-NE continues to assess the need date for the Central Connecticut Reliability Project and we expect that ISO-NE will conclude its evaluation by mid-2011.

Included as part of NEEWS are $84 million of expenditures for associated reliability related projects, all of which have received siting approval and most of which are under construction. The in-service dates for these projects range from later this year through 2013.

Since inception of NEEWS through December 31, 2010, CL&P and WMECO have capitalized approximately $105.9 million and $136.9 million, respectively, in costs associated with NEEWS, of which $38.4 million and $62.6 million, respectively, were capitalized in 2010. The total cost estimate for the NEEWS projects is $1.52 billion. As these projects are completed and put in service, actual costs may differ from these estimates.

On October 4, 2010, NPT and Hydro Renewable Energy entered into a TSA in connection with the Northern Pass transmission project. Northern Pass is comprised of a planned HVDC transmission line from the U.S./Canadian border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire that will be constructed by NPT. Northern Pass will interconnect at the U.S./Canadian border with a planned HVDC transmission line that HQ TransÉnergie, the transmission division of HQ, will construct in Québec.

Consistent with the FERC's February 11, 2011 order accepting without modification the TSA between NPT and Hydro Renewable Energy that was filed on December 15, 2010, NPT will sell to Hydro Renewable Energy 1,200 MW of firm electric transmission rights over the Northern Pass for a 40-year term and charge cost-based rates. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project, and upon commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent. The TSA rates will be based on a deemed capital structure for NPT of 50 percent debt and 50 percent equity. During the development and the construction phases under the TSA, NPT will be recording non-cash AFUDC earnings.

On October 13, 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and on October 14, 2010, NPT filed a presidential permit application with the DOE, which seeks permission to construct and maintain facilities that cross the U.S. border and connect to HQ TransÉnergie's facilities in Canada. NPT anticipates filing additional state and federal permit and siting applications in 2011. Assuming timely regulatory review and siting approvals, NPT expects to commence construction of Northern Pass in 2013 and complete the line with power flowing in late 2015.

We currently estimate that NU's 75 percent share of the Northern Pass transmission project will be approximately $830 million and NSTAR s 25 percent share of the Northern Pass transmission project will be approximately $280 million, for a combined total expected cost of approximately $1.1 billion (including capitalized AFUDC).

In July 2010, CL&P and UI entered into an agreement providing UI an option to make quarterly payments to CL&P in exchange for ownership of specific Connecticut based NEEWS transmission assets as they come into commercial operation. Under the agreement, which has received approval of the FERC and the DPUC, UI will have the right to invest up to $69 million or an amount equal to 8.4 percent of CL&P's costs for the Connecticut portion of these projects, which are expected to aggregate to approximately $828 million. On December 30, 2010, CL&P received the first of these deposits in the amount of $7.2 million. The impact of the UI transaction is reflected in the 2010 capital expenditures and our five-year capital expenditures and rate base forecasts.

On December 17, 2010, CL&P and the Connecticut Transmission Municipal Electric Energy Cooperative (CTMEEC), a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric companies, filed with the DPUC and the FERC a joint application seeking regulatory approval of the transfer of a segment of high voltage transmission lines built by CL&P in the town of Wallingford, Connecticut. FERC approval for the transfer was received on January 31, 2011. The purchase price will be based on the net book value of the assets at the time of the closing of the sale, plus any additional closing adjustments. This segment of lines is projected to have a value of $42.3 million at the anticipated time of closing in May of 2011. CL&P will continue to operate and maintain the lines for CTMEEC. The transaction does not include the transfer of land or equipment not related to electric transmission service. The transaction will not impact our five-year capital plan and is already reflected in CL&P s transmission rate base forecasts.

Distribution Segment: Distribution segment capital expenditures increased by $81.4 million in 2010, as compared with 2009, due to expenditures related primarily to the PSNH Clean Air Project, the WMECO solar generation project, and the Yankee Gas WWL Project.

A summary of distribution segment capital expenditures by company for 2010, 2009 and 2008 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2010**	**2009**	**2008**
CL&P:			
Basic business	$ 126.2	$ 104.6	$ 114.7
Aging infrastructure	104.0	104.1	95.4
Load growth	75.2	74.3	86.5
Total CL&P	305.4	283.0	296.6
PSNH:			
Basic business	41.2	55.5	41.6
Aging infrastructure	19.5	17.8	19.6
Load growth	23.1	25.5	37.0
Total PSNH	83.8	98.8	98.2
WMECO:			
Basic business	17.5	21.5	18.1
Aging infrastructure	10.5	12.2	12.9
Load growth	5.1	4.0	6.8
Total WMECO	33.1	37.7	37.8
Totals - Electric Distribution (excluding Generation)	422.3	419.5	432.6
Yankee Gas	94.6	59.6	44.0
Other	2.0	0.6	0.5
Total Distribution	518.9	479.7	477.1
PSNH Generation:			
Clean air project	149.7	119.3	24.8
Other	27.4	25.7	49.2
Total PSNH Generation	177.1	145.0	74.0
WMECO Generation	10.1	-	-
Total Distribution Segment	$ 706.1	$ 624.7	$ 551.1

For the electric distribution business, basic business includes the relocation of plant, the purchase of meters, tools, vehicles, and information technology. Aging infrastructure relates to the planned replacement of overhead lines, plant substations, transformer replacements, and underground cable replacement. Load growth includes requests for new business and capacity additions on distribution lines and substation overloads. For the natural gas business, basic business includes the relocation of conflicting natural gas facilities due to municipal and state road work and the purchase of meters, tools, and information technology. Aging infrastructure relates to the planned replacement of natural gas facilities. Load growth includes requests for new natural gas service, new service mains and new distributed generation service.

PSNH's Clean Air Project is a wet scrubber project under construction at its Merrimack coal station, the cost of which will be recovered through PSNH's ES rates under New Hampshire law. Construction costs are running below their previously announced cost of $457 million and the project is expected to be completed in mid-2012, about a year ahead of schedule. We currently expect the project to cost approximately $430 million, including capitalized interest and equity returns. Since inception of the project, PSNH has capitalized $296.5 million associated with this project, of which $149.7 million was capitalized in 2010. Construction of the project was approximately 80 percent complete as of December 31, 2010.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the Massachusetts Attorney General concerning WMECO's proposal, under the Massachusetts Green Communities Act, to install 6 MW of solar energy generation in its service territory at an estimated cost of $41 million by the end of 2012. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts. The full cost of this project was approximately $9.4 million, all of which WMECO has capitalized as of December 31, 2010. On January 17, 2011, WMECO announced its plans to develop a second project on a site in Springfield, Massachusetts. WMECO believes this site is capable of accommodating a 4.2 MW solar generation facility. The major permitting and procurement activities for this project are underway and, assuming their favorable and timely completion, WMECO would expect to begin construction during the second quarter of 2011.

In April 2010, Yankee Gas commenced construction of its WWL Project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of its LNG plant. The project is now expected to cost $57.6 million, down from our previously announced cost of approximately $63 million. Construction during 2010, which cost $26.6 million, included the completion of Phase I, a seven-mile segment of pipeline connecting the Cheshire and Wallingford distribution systems, and four miles of Phase II. The remainder of the Phase II pipeline construction (approximately five miles) and the expansion of the vaporization capacity of the LNG facility are expected to be completed by the fourth quarter of 2011. Construction of the project was 46 percent complete as of December 31, 2010 and is currently on schedule.

Strategic Initiatives: We continue to evaluate a number of development projects that will benefit our customers, some of which are detailed below.

Over the past three years, we have participated in discussions with other utilities, policymakers, and prospective developers of renewable energy projects in the New England region regarding a framework whereby renewable power projects built in rural areas of northern New England could be connected to the electric load centers of New England. We believe there are significant opportunities for developers to build wind and biomass projects in northern New England that could help the region meet its renewable portfolio standards. We believe that a collaborative approach among project developers and transmission owners is necessary to be able to construct needed projects and bring their electrical output into the market. We have not yet included any capital expenditures associated with potential projects in our five-year capital program and these discussions are continuing.

On March 31, 2010, CL&P filed with the DPUC an AMI and dynamic pricing plan that included a cost benefit analysis. CL&P concluded that a full deployment of AMI meters accompanied by dynamic pricing options for all CL&P customers would be cost beneficial under a set of reasonable assumptions, identified as the "base case scenario." Under the base case scenario, capital expenditures associated with the installation of the meters are estimated at $296 million, which are included in the Company's five-year capital program. Under CL&P's proposal, installation of meters is proposed to begin in late 2012 and continue through 2016. The DPUC procedural review began in late October 2010 and is scheduled to end in April 2011.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. On July 27, 2010, the DPU approved a settlement agreement between WMECO, the Attorney General and other stakeholders to postpone implementation of a dynamic pricing smart meter pilot program until results of smart meter pilots conducted by three other Massachusetts utilities are gathered and WMECO's meter data management system is operational. WMECO does not expect it will conduct a pilot program prior to 2012.

Projected Capital Expenditures and Rate Base Estimates: Excluding the impacts of the proposed merger with NSTAR, a summary of the projected capital expenditures for the Regulated companies' electric transmission segment and their distribution segment (including generation) by company for 2011 through 2015, including our corporate service companies' capital expenditures on behalf of the Regulated companies, is as follows:

			Year			
(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**2011-2015 Total**
CL&P transmission	$ 137	$ 194	$ 169	$ 229	$ 280	$ 1,009
PSNH transmission	59	75	58	45	56	293
WMECO transmission	229	260	161	75	7	732
NPT	19	23	241	298	241	822
Subtotal transmission	$ 444	$ 552	$ 629	$ 647	$ 584	$ 2,856
CL&P distribution:						
Basic business	$ 135	$ 146	$ 137	$ 218	$ 276	$ 912
Aging infrastructure	131	108	116	116	118	589
Load growth	71	66	65	78	75	355
Total CL&P distribution	337	320	318	412	469	1,856
PSNH distribution:						
Basic business	49	48	48	51	52	248

Aging infrastructure		26		28		40		41		35		170
Load growth		38		41		39		40		45		203
Total PSNH distribution		113		117		127		132		132		621
WMECO distribution:												
Basic business		15		16		16		17		17		81
Aging infrastructure		15		13		13		14		14		69
Load growth		6		10		10		9		9		44
Total WMECO distribution		36		39		39		40		40		194
Subtotal electric distribution	$	486	$	476	$	484	$	584	$	641	$	2,671
PSNH generation:												
Clean air project	$	77	$	34	$	22	$	-	$	-	$	133
Other		35		18		30		29		29		141
Total PSNH generation		112		52		52		29		29		274
WMECO generation		22		9		5		5		5		46
Subtotal generation	$	134	$	61	$	57	$	34	$	34	$	320
Yankee Gas distribution:												
Basic business	$	37	$	31	$	30	$	31	$	33	$	162
Aging infrastructure		30		48		50		51		52		231
Load growth		16		20		46		47		35		164
WWL project		30		-		-		-		-		30
Total Yankee Gas distribution	$	113	$	99	$	126	$	129	$	120	$	587
Corporate service companies	$	32	$	28	$	35	$	34	$	28	$	157
Total	$	1,209	$	1,216	$	1,331	$	1,428	$	1,407	$	6,591

Yankee Gas determines the amount of capital spending by category based on business needs and opportunities. Future capital spending will likely be affected by price differences between the cost of natural gas with respect to home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements.

Actual capital expenditures could vary from the projected amounts for the companies and periods above. Economic conditions in the northeast could impact the timing of our major transmission projects. Most of these capital investment projections, including those for NPT, assume timely regulatory approval, which in most cases requires extensive review. Delays in or denials of those approvals could reduce the levels of expenditures, associated rate base, and anticipated EPS growth.

Based on the 2010 actual and 2011 through 2015 projected capital expenditures, the 2010 actual and 2011 through 2015 projected transmission, distribution and generation rate base as of December 31 of each year are as follows:

	Year					
(Millions of Dollars)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
CL&P transmission	$ 2,149	$ 2,114	$ 2,178	$ 2,234	$ 2,394	$ 2,552
PSNH transmission	341	360	406	406	505	540
WMECO transmission	269	459	650	730	834	803
NPT	-	-	-	-	-	830
Total transmission	2,759	2,933	3,234	3,370	3,733	4,725
CL&P distribution	2,273	2,382	2,540	2,736	3,007	3,297
PSNH distribution	803	866	947	1,006	1,070	1,143
WMECO distribution	412	422	425	429	439	453
Total electric distribution	3,488	3,670	3,912	4,171	4,516	4,893
PSNH generation	394	399	727	742	740	728
WMECO generation	11	27	31	31	33	35
Total generation	405	426	758	773	773	763
Yankee Gas distribution	682	743	756	790	847	969
Total	$ 7,334	$ 7,772	$ 8,660	$ 9,104	$ 9,869	$ 11,350

Transmission Rate Matters and FERC Regulatory Issues

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the rules by which these parties participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent from all market participants, has served as the RTO for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff, subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines the portion of the costs of our major transmission facilities that are regionalized throughout New England.

Transmission - Wholesale Rates: NU's transmission rates recover total transmission revenue requirements, ensuring that we recover all regional and local revenue requirements. These rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from, or refund to, customers. As of December 31, 2010, NU was in a total overrecovery position of $40.9 million ($37.2 million for CL&P, $3 million for PSNH, and $0.7 million for WMECO), which will be refunded to customers in June 2011.

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects. All appeals of FERC's orders on the ROE for New England transmission owners have been denied.

NEEWS Incentives: On November 17, 2008, the FERC issued an order granting incentives and rate amendments to us and National Grid USA for the NEEWS projects. The approved incentives included (1) an ROE of 12.89 percent, representing an incentive of 125 basis points; (2) 100 percent inclusion of CWIP in rate base; and (3) full recovery of prudently incurred costs if NEEWS, or any portion thereof, is cancelled as a result of factors beyond NU's or National Grid USA's control. Several parties have sought rehearing of this yet to be acted upon FERC order.

Legislative Matters

2010 Federal Legislation: On March 23, 2010, President Obama signed into law the 2010 Healthcare Act. The 2010 Healthcare Act was amended by a Reconciliation Bill signed into law on March 30, 2010. The 2010 Healthcare Act includes a provision that eliminated the tax deductibility of certain PBOP contributions equal to the amount of the federal subsidy received by companies like NU, which sponsor retiree health care benefit plans with a prescription drug benefit that is actuarially equivalent to Medicare Part D. The tax deduction eliminated by this legislation represented a loss of previously recognized deferred income tax assets established through 2009 and as a result, these assets were written down by approximately $18 million in the first quarter of 2010. Since the electric and natural gas distribution companies are cost-of-service and rate-regulated, a portion of the $18 million was able to be deferred and recovered through future rates. For the year ended December 31, 2010, NU deferred approximately $15 million of recoverable write-offs related to these businesses and reduced 2010 earnings on a net basis by approximately $3 million of non-recoverable costs. In addition, as a result of the elimination of the tax deduction in 2010, NU was not able to recognize approximately $2 million of net annual benefits.

On September 27, 2010, President Obama signed into law the Small Business Jobs and Credit Act of 2010, which extends the bonus depreciation provisions of the American Recovery and Reinvestment Act of 2009 to small and large businesses through 2010. This extended stimulus provided NU with cash flow benefits of approximately $100 million.

On December 17, 2010, President Obama signed into law the 2010 Tax Act, which, among other things, provides 100 percent bonus depreciation for tangible personal property placed in service after September 8, 2010, and through December 31, 2011. For tangible personal property placed in service after December 31, 2011, and through December 31, 2012, the 2010 Tax Act provides for 50 percent bonus depreciation. We expect the 2010 Tax Act to provide NU with cash flow benefits of approximately $250 million in 2011 and approximately $450 million to $550 million over the period 2011 through 2013.

2010 Connecticut Legislation: In May 2010, the Connecticut Legislature approved a state budget for the 2010-2011 fiscal year, which calls for the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds that would be amortized over eight years. These bonds will be repaid through a charge on the bills of customers of CL&P and other Connecticut electric distribution companies. For CL&P, the revenue to pay interest and principal on the bonds would come from a continuation of a portion of its CTA, which would have otherwise ended by December 31, 2010 with the final principal and interest payment on its RRBs, and the diversion of about one-third of the annual funding for C&LM programs beginning in April 2012. On September 29, 2010, the DPUC approved a financing order for the bonds. A lawsuit filed by a state senator against the DPUC could delay the issuance. By order dated December 21, 2010, the trial court dismissed the state senator s suit on jurisdictional grounds, and the state senator promptly appealed that order to the Connecticut Appellate Court. The DPUC has requested that the case be transferred to the Connecticut Supreme Court and decided on an expedited schedule. In addition, several bills have been introduced by the state senator and other state lawmakers to rescind the law authorizing these bonds. Unlike the RRBs issued in 2001, the revenues, interest expense and amortization expense associated with these bonds, should they be issued, will not be reflected on CL&P s financial statements.

Regulatory Developments and Rate Matters

Connecticut - CL&P:

Distribution Rates: On January 8, 2010, CL&P filed an application with the DPUC to raise distribution rates by $133.4 million (later revised to $129 million) to be effective July 1, 2010 and by an additional $44.2 million (later revised to $41.4 million) to be effective July 1, 2011. On June 30, 2010, the DPUC issued a final order in the distribution rate case, which approved annualized rate increases of $63.4 million effective July 1, 2010 and an additional $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the amortization of the aforementioned CL&P RRBs, which more than offset the revenue requirements associated with the January 1, 2011 distribution rate increase. While CL&P s earnings benefitted in the second half of 2010 from the rate decision as a result of declines in depreciation and maintenance expense, cash flow benefits will not begin until early 2011 when customer bills begin to reflect an approximately $110 million increase in distribution rates. That $110 million increase reflects the two distribution rate increases and the recovery of approximately $32 million in maintenance expense that was deferred for recovery from the second half of 2010 to 2011 and the first half of 2012. In its decision, the DPUC also maintained CL&P s authorized distribution segment regulatory ROE of 9.4 percent.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under SS rates, and large commercial and industrial customers who do not choose competitive suppliers are served under LRS rates. CL&P is fully recovering from customers the costs of its SS and LRS services. Effective January 1, 2011, the DPUC approved a decrease to CL&P s total average SS rate of approximately 7.8 percent and a slight increase to CL&P s total average LRS rate of approximately 0.8 percent. The energy supply portion of the total average SS rate decreased from 11.282 cents per KWh to 9.732 cents per KWh while the energy supply portion of the total average LRS rate increased from 7.062 cents per KWh to 7.193 cents per KWh.

CTA and SBC Reconciliation: On March 31, 2010, CL&P filed with the DPUC its 2009 CTA and SBC reconciliation, which compared CTA and SBC revenues charged to customers to revenue requirements and allows for full recovery of revenue requirements. For the 12 months ended December 31, 2009, total CTA revenue requirements exceeded CTA revenues by $46.9 million. For the 12 months ended December 31, 2009, the SBC revenues exceeded SBC revenue requirements by $23.7 million.

On November 10, 2010, a decision in the 2009 CTA and SBC docket was issued approving the 2009 CTA and SBC reconciliations as filed. The decision stated that the CTA and SBC rates would need to be reset effective January 1, 2011 based on current projections. On December 22, 2010, the DPUC approved new CTA and SBC rates, effective January 1, 2011, using updated information provided by CL&P. Based on that updated information, the CTA rate decreased from 1.054 cents per KWh to 0.332 cents per KWh and the SBC rate decreased from 0.207 cents per KWh to 0.037 cents per KWh.

FMCC Filing: On February 5, 2010, CL&P filed with the DPUC its semi-annual filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2009 through December 31, 2009, and also included the previously filed revenues and expenses for the January 1, 2009 through June 30, 2009 period. The filing identified a total net underrecovery of $6.5 million, which includes the remaining uncollected portions from previous filings. On November 10, 2010, the DPUC issued a final decision accepting CL&P's calculations of GSC, bypassable FMCC and nonbypassable FMCC revenues and expenses for the period July 1, 2009 through December 31, 2009. On August 5, 2010, CL&P filed with the DPUC its semi-annual FMCC filing for the period January 1, 2010 through June 30, 2010. The filing identified a total net underrecovery of $7 million for the period, which includes the remaining uncollected portions from previous filings. On January 6, 2011, the DPUC issued a decision accepting CL&P's calculations of GSC, bypassable FMCC and nonbypassable FMCC revenues and expenses for the period January 1, 2010 through June 30, 2010.

On February 4, 2011, CL&P filed with the DPUC its semi-annual filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2010 through December 31, 2010, and also included the previously filed revenues and expenses for the January 1, 2010 through June 30, 2010 period. The filing identified a total net overrecovery of $0.3 million, which includes the remaining uncollected portions from previous filings. We do not expect the outcome of the DPUC's review of this filing to have a material adverse impact on CL&P's financial position, results of operations or cash flows.

Procurement Fee Rate Proceedings: In prior years, CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its transition service procurement fee, which was effective for the years 2004, 2005 and 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 and 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings, through a CTA reconciliation process. On January 15, 2009, the DPUC issued a final decision in this docket reversing its December 2005 draft decision and stated that CL&P was not eligible for the procurement incentive compensation for 2004. A $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers was established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009. On February 4, 2010, the Connecticut Superior Court reversed the DPUC decision. The Court remanded the case back to the DPUC for the correction of several specific errors. On February 22, 2010, the DPUC appealed the Connecticut Superior Court s February 4, 2010 decision to the Connecticut Appellate Court, which then transferred the appeal to the Connecticut Supreme Court. A decision is expected from the Connecticut Supreme Court in late 2011 or early 2012.

Connecticut Yankee Gas

Distribution Rates: On January 7, 2011, Yankee Gas filed an application with the DPUC to increase its distribution rates by $32.8 million, or 7.3 percent, to be effective July 1, 2011, and by an additional $13 million, or 2.8 percent, to be effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized regulatory ROE of 10.1 percent, that $57.6 million of costs associated with the WWL Project be placed into rates, and a substantial increase in capital funding to replace bare steel and cast iron pipe throughout its natural gas distribution system. A final decision is expected in June 2011.

New Hampshire:

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement agreement of PSNH s permanent distribution rate case, effective July 1, 2010, reached in April 2010 among PSNH, the NHPUC staff and the Office of Consumer Advocate. Under the agreement, the settling parties agreed to a net annualized distribution rate increase of $45.5 million, effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years. The $45.5 million increase was in addition to the $25.6 million temporary increase that became effective August 1, 2009 and includes $13.7 million to reconcile the difference between the temporary rates and the permanent rates back to August 1, 2009. The projected decrease of $2.9 million on July 1, 2011 reflects primarily the end of the one year recovery of the $13.7 million reconciliation on that date. PSNH also agreed not to file a new distribution rate request prior to July 1, 2015. During the term of the settlement, PSNH s ability to propose changes to its permanent distribution rate level will be limited to situations where its 12-month distribution ROE falls below 7 percent for two consecutive quarters or certain specified external events occur, as described in the settlement. If PSNH's 12-month distribution ROE rolling average is greater than 10 percent, anything over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent.

ES and SCRC Filings: On June 11, 2010, PSNH petitioned the NHPUC to change the 2010 ES and SCRC rates. On June 28, 2010, the NHPUC issued orders approving ES and SCRC rates of 8.78 cents per KWh and 1.20 cents per KWh, respectively, effective July 1, 2010. On September 21, 2010, PSNH filed petitions with the NHPUC requesting changes in both its ES and SCRC annual rates for the period January 1, 2011 through December 31, 2011. On December 16, 2010, PSNH submitted final proposed ES and SCRC rates of 8.67 cents per KWh and 1.17 cents per KWh, respectively. On December 29, 2010, the NHPUC issued orders approving the ES and SCRC rate petitions as filed.

TCAM Filing: On June 3, 2010, PSNH filed a petition with the NHPUC requesting reconciliation of the TCAM revenues and costs for 2009, and recovery of forecasted retail transmission costs for the period July 1, 2010 through June 30, 2011. On June 11, 2010, PSNH petitioned the NHPUC for a TCAM rate of 1.501 cents per KWh. On June 28, 2010, the NHPUC issued an order approving the TCAM rate as filed.

ES and SCRC Reconciliation: On an annual basis, PSNH files with the NHPUC an ES/SCRC cost reconciliation filing for the preceding year. On April 30, 2010, PSNH filed its 2009 ES/SCRC reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation and power purchase activities. As of December 31, 2009 PSNH had an ES regulatory asset and an SCRC regulatory asset of $4.4 million and $3.9 million, respectively, which is being recovered from customers in the 2010 ES/SCRC rate period.

Merrimack Clean Air Project: On July 7, 2009, the New Hampshire Site Evaluation Committee determined that PSNH's Clean Air Project to install wet scrubber technology at its Merrimack Station was not subject to the Committee's review as a "sizeable" addition to a power plant under state law. That Committee upheld its decision in an order dated January 15, 2010, denying requests for rehearing. This order was appealed on February 23, 2010. On April 15, 2010, the New Hampshire Supreme Court determined that it would accept the appeal. Briefs have been filed and the Court has scheduled oral arguments for March 10, 2011. We do not believe that the appeal will have a material impact on the timing or costs of the project. PSNH is continuing with construction of this project and has capitalized $296.5 million since inception of the project through December 31, 2010.

Massachusetts:

Distribution Rates: On July 16, 2010, WMECO filed an application with the DPU, requesting approval of a $28.4 million increase in distribution rates and a decoupling plan to be effective February 1, 2011. Among other items, WMECO sought a distribution segment regulatory ROE of 10.5 percent, recovery over five years of its remaining deferred December 2008 and 2010 major storm costs and recovery of its hardship receivable costs. On January 31, 2011, the DPU issued a final decision approving an annualized rate increase of $16.8 million effective February 1, 2011, an authorized distribution segment regulatory ROE of 9.6 percent, a decoupling plan with no inflation adjustment, recovery of certain 2008 and 2010 major storm costs over five years, and recovery of certain hardship receivable costs.

Basic Service Rates: In 2010, fixed basic service rates ranged from 7.647 cents per KWh to 8.237 cents per KWh for residential customers, 8.44 cents per KWh to 8.972 cents per KWh for small commercial and industrial customers, and 7.052 cents per KWh to 8.893 cents per KWh for medium and large commercial and industrial customers. Effective January 1, 2011, the rates for all basic service customers changed to reflect the basic service solicitations conducted by WMECO in November 2010. Fixed basic service rates for residential customers decreased to 6.993 cents per KWh, rates for small commercial and industrial customers decreased to 8.006 cents per KWh and rates for large commercial and industrial customers decreased to 7.405 cents per KWh. The fixed price increased by 0.063 cents per KWh for street lighting customers to 5.822 cents per KWh.

Transition Cost Reconciliation: On May 12, 2010, WMECO filed its 2009 cost reconciliation for transition, transmission, basic/default service, basic/default service adder, and capital projects scheduling list. A public hearing was held on July 12, 2010. An evidentiary hearing was held on November 12, 2010. The briefing period ended on December 17, 2010. We do not expect the outcome of the DPU's review of this filing to have a material adverse impact on WMECO's financial position, results of operations or cash flows.

Pension Factor Reconciliation Filing: On July 2, 2009, WMECO filed the 2008 reconciliation for its pension factor revenues and expenses. An evidentiary hearing was held on March 26, 2010 and the briefing period ended on May 20, 2010. On August 31, 2010, the DPU issued an approval order. The order did not have a material adverse impact on WMECO's financial position, results of operations or cash flows.

Deferred Contractual Obligations

Refer to Note 12D, "Commitments and Contingencies   Deferred Contractual Obligations," to the consolidated financial statements and also Part I, Item 3, "Legal Proceedings," for discussion of recent changes with regard to the CYAPC, YAEC, and MYAPC litigation against the DOE.

Enterprise Risk Management

We have implemented an Enterprise Risk Management methodology for identifying the principal risks of the Company. Enterprise Risk Management involves the application of a well-defined, enterprise-wide methodology that enables our Risk and Capital Committee, comprised of our senior officers, to oversee the identification, management and reporting of the principal risks of the business. 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 condition, results of operations or cash flows. The findings of this process are periodically discussed with our Board of Trustees.

Critical Accounting Policies and Estimates

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 our Audit Committee of the Board of Trustees significant matters relating to critical accounting policies and estimates. Our critical accounting policies and estimates are discussed below. See the combined notes to our consolidated financial statements for further information concerning the accounting policies, estimates and assumptions used in the preparation of our consolidated financial statements.

Regulatory Accounting: The accounting policies of the Regulated companies conform to GAAP applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process.

The application of accounting guidance applicable to 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. 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 consolidated 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 if we could not

conclude that it is probable that costs would be recovered or reflected in future rates, the costs would be charged to earnings in the period in which they were incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then we would record the charge in earnings at that time.

For further information, see Note 2, "Regulatory Accounting," to the consolidated financial statements.

Unbilled Revenues: The determination of retail energy sales to residential, commercial and industrial customers is based on the reading of meters, which occurs on a systematic basis throughout the month. Billed revenues are based on these meter readings and the majority of recorded revenues is based on actual billings. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and an estimated amount of unbilled revenues is recorded.

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 changes in estimating methodology occur and under other circumstances. There were no changes in estimating methodology in 2010.

The Regulated companies estimate unbilled revenues monthly using the daily load cycle (DLC) method. The DLC 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 calendar month sales to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective rate classes and then applying an average rate to the estimate of unbilled 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.

For further information, see Note 1M, "Summary of Significant Accounting Policies - Revenues," to the consolidated financial statements.

Pension and PBOP: Our subsidiaries participate in a Pension Plan covering certain of our regular employees and in a PBOP Plan to provide certain health care benefits, primarily medical and dental, and life insurance benefits to retired employees. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions. 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 pension expense for the Pension Plan was $80.4 million, $39.7 million and $2.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. The pre-tax net PBOP Plan expense was $41.6 million,

$37.2 million and $36.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

We develop key assumptions for purposes of measuring the plans liabilities as of December 31 and expenses for the subsequent year. These assumptions include the long-term rate of return on plan assets, discount rate, compensation/progression rate, and health care cost trend rates and are discussed below.

Long-Term Rate of Return on Plan Assets: In developing this assumption, we consider historical and expected returns and input from our actuaries and 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. We used aggregate expected long-term rate of return assumptions of 8.25 percent and 8.75 percent on Pension Plan assets and PBOP Plan life and non-taxable health assets and a 6.45 percent and 6.85 percent for PBOP taxable health assets as of December 31, 2010 and 2009, respectively.

Discount Rate: Payment obligations related to the Pension Plan and PBOP Plan are discounted at interest rates applicable to the timing of the plans cash flows. The discount rate that is utilized in determining the pension and PBOP obligations is based on a yield-curve approach. The yield curve is developed from the top quartile of "AA-rated" Moody s and S&P s bonds without callable features outstanding as of December 31, 2010. The discount rates determined on this basis are 5.57 percent for the Pension Plan and 5.28 percent for the PBOP Plan as of December 31, 2010 and 5.98 percent and 5.73 percent for the respective plans as of December 31, 2009.

Compensation/Progression Rate: This assumption reflects the expected long-term salary growth rate, which impacts the estimated benefits that pension plan participants receive in the future. We used a compensation/progression rate of 3.5 percent and 4.0 percent as of December 31, 2010 and 2009, respectively. The 3.5 percent rate reflects our current expectation of future salary increases and promotions, including consideration of the levels of increases built into union contracts.

Actuarial Determination of Expense: Pension and PBOP expense are determined by our actuaries and consist 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, offset by the expected return on plan assets. Actuarial gains and losses represent differences between assumptions and actual information or updated assumptions.

We determine the expected return on plan assets by applying our assumed rate of return to a calculation of plan assets that recognizes investment gains or losses over a four-year period after the year in which they occur, which reduces year-to-year volatility. Investment gains or losses for this purpose are the difference between the calculated expected return using our long-term rate of return assumption

and the actual return or loss based on the change in the fair value of assets during the year. As of December 31, 2010, investment losses that remain to be reflected in the calculation of plan assets over the next four years were $238.9 million and $1.8 million for the Pension Plan and PBOP Plan, respectively. These asset losses will be subject to amortization with other unrecognized actuarial gains or losses as they are reflected in the calculation of plan assets. The plans currently amortize unrecognized actuarial gains or losses as a component of pension and PBOP expense over the average future employee service period of approximately 10 and 9 years, respectively. As of December 31, 2010, the net unrecognized actuarial losses on the Pension and PBOP Plan liabilities, subject to amortization, were $676.7 million and $171.3 million, respectively.

Forecasted Expenses and Expected Contributions: Based upon the assumptions and methodologies discussed above, we estimate that forecasted expense for the Pension Plan and PBOP Plan will be $124.9 million and $42.8 million, respectively, in 2011, which is included in our earnings guidance. 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.

We expect to continue our policy to contribute to the PBOP Plan at the amount of PBOP expense, excluding curtailments and special benefit amounts and adding contributions for the amounts received from the federal Medicare subsidy. NU's policy is to annually fund the Pension Plan in an amount at least equal to what will satisfy the requirements of ERISA and the Internal Revenue Code. NU's Pension Plan has historically been well funded, and a contribution was not required to be made from 1991 until the third quarter of 2010, when PSNH made a contribution to the plan of $45 million. Using the segment rate approach as allowed under PPA guidelines, our Pension Plan funded ratio (the value of plan assets divided by the funding target in accordance with the requirement of the PPA) was 92 percent as of January 1, 2010. We currently estimate that quarterly contributions aggregating to a total of approximately $145 million will be made in 2011.

Sensitivity Analysis: The following represents the increase to the Pension Plan s and PBOP Plan s reported cost as a result of a change in the following assumptions by 50 basis points (in millions):

	As of December 31,							
	Pension Plan Cost				Postretirement Plan Cost			
Assumption Change		**2010**		**2009**		**2010**		**2009**
Lower long-term rate of return	$	10.7	$	11.1	$	1.2	$	1.7
Lower discount rate	$	13.4	$	12.0	$	2.2	$	1.5
Higher compensation increase	$	6.1	$	6.0		N/A		N/A

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 7.5 percent for determining 2010 PBOP Plan expense. For 2011 through 2013, the rate is 7 percent, subsequently decreasing one half percentage point per year to an ultimate rate of 5 percent in 2017. The effect of increasing the health care cost trend by one percentage point would have increased service and interest cost components of PBOP Plan expense by $1.2 million in 2010, with a $14.5 million impact on the postretirement benefit obligation.

See Note 10A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements for more information.

Goodwill and Intangible Assets: We are required to test goodwill balances for impairment at least annually by applying a fair value-based test that requires us to use estimates and judgment. We have selected October 1st of each year as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount of the goodwill. If goodwill is deemed to be impaired, it is written down in the current period to the extent of the impairment.

We performed an impairment analysis as of October 1, 2010 for the Yankee Gas goodwill balance of $287.6 million. We determined that no triggering events occurred in 2010 that would have required testing before or after October 1st. We determined that the fair value of Yankee Gas substantially exceeds its carrying value and no impairment exists. In performing the evaluation, we estimated the fair value of the Yankee Gas reporting unit and compared it to the carrying amount of the reporting unit, including goodwill. We estimated the fair value of Yankee Gas using a discounted cash flow methodology and two market approaches that analyze comparable companies or transactions. This evaluation requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, long-term earnings and merger multiples of comparable companies.

We determined the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the ROE is developed using risk-free rates, equity premiums and a beta representing Yankee Gas' volatility relative to the overall market. The resulting discount rate is intended to be comparable to a rate that would be applied by a market participant. The discount rate may change from year to year as it is based on external market conditions. The discount rate decreased in 2010, as compared to 2009, as a result of lower beta and risk-free treasury rates.

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. Such differences are the result of timing of the deduction for expenses, as well as any impact of permanent differences resulting from tax credits, non-tax deductible expenses, in addition to various 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 consolidated 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. Adjustments to these estimates can significantly impact our consolidated financial statements.

A reconciliation of expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in Note 11, "Income Taxes," to the consolidated financial statements.

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. We follow generally accepted accounting principles to address the methodology to be used in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties. The determination of whether a tax position meets the recognition threshold under this guidance is based on facts, circumstances and information 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, 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:

Accounting for Environmental Reserves: Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to environmental reserves 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 options (ranging from no action 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. 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.

For further information, see Note 12A, "Commitments and Contingencies- Environmental Matters," to the consolidated financial statements.

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 the Company's derivative contracts that are recorded at fair value, marketable securities held in NU s supplemental benefit trust and WMECO s spent nuclear fuel trust, our valuations of investments in our pension and PBOP plans, and nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs.

Derivative assets are a large portion of our total assets measured at fair value (excluding assets held in our external pension and PBOP trusts), and derivative liabilities comprise almost all of our total liabilities measured at fair value as of December 31, 2010. Changes in fair value of the regulated company derivative contracts are recorded as Regulatory assets or liabilities, as we expect to recover the costs of these contracts in rates. 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. A significant portion of our derivative liabilities relate to the Regulated companies, for which changes in fair value do not affect our earnings and are not material to our liquidity or capital resources because the costs and benefits of the contracts are recoverable from or refundable to customers on a timely basis.

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, future contract quantities under full requirements and supplemental sales 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.

For further information see Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," included in this Annual Report on Form 10-K for a sensitivity analysis of how changes in the prices of energy and energy related products would impact earnings.

For further information on derivative contracts and marketable securities, see Note 1J, "Summary of Significant Accounting Policies - Derivative Accounting," Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the consolidated financial statements.

Other Matters

Environmental Matter: HWP, a subsidiary of NU, continues to investigate the potential need for additional remediation at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal utility, in 1902. As of December 31, 2010, HWP has a $2.9 million reserve for estimated costs that HWP considers probable over the remaining life of the project. Although a material increase to the reserve is not presently anticipated, management cannot reasonably estimate potential additional investigation or remediation costs because these costs would depend, among other things, on the nature, extent and timing of additional investigation and remediation that may be required by the MA DEP.

For further information, see Note 12A, "Commitments and Contingencies- Environmental Matters," to the consolidated financial statements.

Contractual Obligations and Commercial Commitments: Information regarding our contractual obligations and commercial commitments as of December 31, 2010 is summarized annually through 2015 and thereafter as follows:

NU

(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
Long-term debt maturities [a] [b]	$ 66.3	$ 267.3	$ 305.0	$ 275.0	$ 150.0	$ 3,327.9	$ 4,391.5
Estimated interest payments on existing debt [c]	236.2	231.8	220.6	208.9	194.8	1,871.4	2,963.7
Capital leases [d]	2.5	2.6	2.4	2.0	2.0	11.4	22.9
Operating leases [e]	7.9	7.0	6.8	4.9	4.5	19.1	50.2
Funding of pension obligations [e] [j]	145.0	160.0	100.0	90.0	40.0	-	535.0
Funding of other postretirement benefit obligations [e]	42.8	41.9	24.2	21.7	20.2	-	150.8
Estimated future annual companies costs [f]	641.2	719.4	596.9	550.5	478.6	3,404.1	6,390.7
Other purchase commitments [e] [h]	1,570.4	-	-	-	-	-	1,570.4
Total [g] [i]	$ 2,712.3	$ 1,430.0	$ 1,255.9	$ 1,153.0	$ 890.1	$ 8,633.9	$ 16,075.2

CL&P

(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
Long-term debt maturities [a] [b]	$ 62.0	$ -	$ -	$ 150.0	$ 100.0	$ 2,031.7	$ 2,343.7
Estimated interest payments on existing debt [c]	133.8	133.8	133.8	133.8	124.1	1,381.7	2,041.0
Capital leases [d]	1.9	2.0	2.0	1.8	1.8	11.3	20.8

Operating leases (e)	7.2	6.8	6.7	6.5	6.5	23.0	56.7
Funding of other postretirement benefit obligations (e)	17.0	16.6	8.1	7.3	6.8	6.4	62.2
Estimated future annual long-term contractual costs (f)	284.2	415.1	436.5	451.5	397.7	3,129.5	5,114.5
Other purchase commitments (e) (h)	598.2	-	-	-	-	-	598.2
Total (g) (i)	$ 1,104.3	$ 574.3	$ 587.1	$ 750.9	$ 636.9	$ 6,583.6	$ 10,237.1

(a)

Included in our debt agreements are usual and customary positive, negative and financial covenants. Non-compliance with certain covenants, for example timely payment of principal and interest, may constitute an event of default, which could cause an acceleration of principal payments in the absence of receipt by us of a waiver or amendment. Such acceleration would change the obligations outlined in the table of contractual obligations and commercial commitments.

(b)

Long-term debt maturities exclude $301 million and $243.8 million for NU and CL&P, respectively, of fees and interest due for spent nuclear fuel disposal costs, a positive $11.8 million for NU of net changes in fair value of hedged debt and a negative $5.1 million and $4.4 million for NU and CL&P, respectively, of net unamortized premium and discount as of December 31, 2010.

(c)

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 average of the 2010 floating-rate resets 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. Interest payments on debt that have an interest rate swap in place are estimated using the effective cost of debt resulting from the swap rather than the underlying interest cost on the debt, subject to the fixed and floating methodologies.

(d)

The capital lease obligations include imputed interest of $10.7 million and $10.2 million for NU and CL&P, respectively, as of December 31, 2010.

(e)

Amounts are not included on our consolidated balance sheets.

(f)

Other than the net mark-to-market changes on respective derivative contracts held by both the Regulated companies and NU Enterprises, these obligations are not included on our consolidated balance sheets. On February 7, 2010, an explosion occurred at the construction site of Kleen Energy Systems, LLC s 620 MW generation project with which CL&P has a Contract for Differences (CfD) contract. This event could delay or change CL&P s estimated payments under the CfD contract. For further information, see Note 12C, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements.

(g)

Does not include unrecognized tax benefits of $101.2 million for NU and $80.8 million for CL&P as of December 31, 2010, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities. Also does not include an NU $50 million contingent commitment 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.

(h)

Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases, estimated future annual regulated company costs and the estimated future annual NU Enterprises costs. These payments are subject to change as certain purchase orders include estimates based on projected quantities of material and/or services that are provided on demand, the timing of which cannot be determined. Because payment timing cannot be determined, we include all open purchase order amounts in 2011.

(i)

For NU, excludes other long-term liabilities, including a significant portion of the unrecognized tax benefits described above, deferred contractual obligations ($133.1 million), environmental reserves ($37.1 million), various injuries and damages reserves ($35.1 million), employee medical insurance reserves ($6.9 million), long-term disability insurance reserves ($12 million) and the ARO liability reserves ($53.3 million) as we cannot make reasonable estimates of the timing of payments. For CL&P, excludes unrecognized tax benefits described above, deferred contractual obligations ($91.7 million) environmental reserves ($2.8 million), various injuries and damages reserves ($23.5 million), employee medical insurance reserves ($2.2 million), long-term disability insurance reserves ($3.8 million) and the ARO liability reserves ($29.3 million).

(j)

These amounts represent NU's estimated minimum pension contributions to its qualified Pension Plan required under ERISA and the Internal Revenue Code. Contributions in 2012 through 2015 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.

RRB amounts are non-recourse to us, have no required payments over the next five years and are not included in this table. The Regulated companies' standard offer service contracts and default service contracts are also not included in this table. For further information regarding our contractual obligations and commercial commitments, see the consolidated statements of capitalization and Note 8, "Short-Term Debt," Note 9, "Long-Term Debt," Note 10A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 12C, "Commitments and Contingencies - Long-Term Contractual Arrangements," and Note 13, "Leases," to the consolidated financial statements.

Web Site: Additional financial information is available through our web site at www.nu.com.

RESULTS OF OPERATIONS   NORTHEAST UTILITIES AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for NU included in this Annual Report on Form 10-K for the years ended December 31, 2010, 2009 and 2008:

Comparison of 2010 to 2009:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 4,898.2	$ 5,439.4	$ (541.2)	(9.9)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,985.6	2,629.6	(644.0)	(24.5)
Other Operating Expenses	958.4	1,001.2	(42.8)	(4.3)
Maintenance	210.3	234.2	(23.9)	(10.2)
Depreciation	300.7	309.6	(8.9)	(2.9)
Amortization of Regulatory Assets, Net	95.7	13.3	82.4	(a)
Amortization of Rate Reduction Bonds	232.9	217.9	15.0	6.9
Taxes Other Than Income Taxes	314.7	282.2	32.5	11.5
Total Operating Expenses	4,098.3	4,688.0	(589.7)	(12.6)
Operating Income	$ 799.9	$ 751.4	$ 48.5	6.5 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 3,802.0	$ 4,358.4	$ (556.4)	(12.8)%
Natural Gas Distribution	434.3	449.6	(15.3)	(3.4)
Total Distribution	4,236.3	4,808.0	(571.7)	(11.9)
Transmission	625.6	577.9	47.7	8.3
Total Regulated Companies	4,861.9	5,385.9	(524.0)	(9.7)
Competitive Businesses	80.3	81.3	(1.0)	(1.2)
Other and Eliminations	(44.0)	(27.8)	(16.2)	(58.3)

NU	$ 4,898.2	$ 5,439.4	$ (541.2)	(9.9)%

A summary of our retail electric sales and firm natural gas sales were as follows:

	For the Years Ended December 31,			
	2010	2009	Increase/ (Decrease)	Percent
Retail Electric Sales in GWh	34,230	33,645	585	1.7%
Firm Natural Gas Sales in Million Cubic Feet	43,251	42,450	801	1.9%

Our Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower generation service and related congestion charges ($574 million) and lower CL&P delivery-related FMCC ($39 million), partially offset by higher retail transmission revenues ($66 million) and higher transition cost recoveries ($48 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. In addition, Regulated companies revenues that eliminate in consolidation decreased by $92 million.

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The portion of electric distribution revenues that impacts earnings increased $40 million due primarily to a 1.7 percent increase in retail electric sales due to warmer than normal summer weather and PSNH's rate changes that were effective July 1, 2010. A decrease in natural gas revenues was due primarily to lower cost of fuel, as fuel costs are fully recovered in revenues from sales to our customers, offset by an increase in sales volume. Firm natural gas sales increased 1.9 percent in 2010 compared to 2009.

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Improved transmission segment revenues resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to the following:

(Millions of Dollars)	**2010 Increase/(Decrease) as compared to 2009**
Lower GSC supply costs, deferred fuel costs and other purchased power costs at CL&P	$ (437.4)
An increased level of ES customer migration to third party electric suppliers, partially offset by higher retail sales at PSNH	(157.4)
Lower basic/default service supply costs at WMECO	(34.9)
Lower prices on purchased natural gas, partially offset by a lower net underrecovery in 2010 at Yankee Gas	(19.7)
Increased competitive businesses' expenses due primarily to lower Select Energy mark-to-market gains	5.4
	$ (644.0)

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, due primarily to:

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Lower distribution and transmission segment expenses of $66 million were due primarily to lower costs that are recovered through distribution tracking mechanisms that have no earnings impact ($65 million), such as retail transmission, RMR and customer service expenses, and lower uncollectibles expense at Yankee Gas ($16 million), partially offset by higher electric distribution and natural gas expenses ($22 million and $3 million, respectively), including higher pension costs and storm restoration costs, and higher transmission segment expenses ($4 million). In addition, amounts that eliminate in consolidation primarily related to service company charges decreased by $45 million.

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Higher NU parent and other companies expenses of $22 million due primarily to costs incurred in 2010 related to NU's proposed merger with NSTAR and higher pension and environmental costs.

Maintenance

Maintenance decreased in 2010, as compared to 2009, due primarily to the allowed regulatory deferral of approximately $32 million as a result of the June 30, 2010 CL&P rate case decision, of which $29.5 million was recognized as a deferral in maintenance expense, lower boiler and maintenance costs at PSNH s generation business ($12 million), offset by higher distribution segment overhead line expenses ($13 million), higher distribution segment vegetation management costs ($2 million) and higher transmission segment routine station maintenance expenses ($2 million).

Depreciation

Depreciation decreased in 2010, as compared to 2009, due primarily to a lower depreciation rate being used at CL&P as a result of the distribution rate case decision that was effective July 1, 2010, partially offset by higher utility plant balances resulting from completed construction projects placed into service in 2010.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net increased in 2010, as compared to 2009, due primarily to a higher recovery of CTA costs at CL&P ($39 million), higher PSNH amortization on the ES deferral and TCAM ($42 million and $11 million, respectively), and previously deferred unrecovered stranded generation costs at WMECO ($11 million), partially offset by the impact of the 2010 Healthcare Act related to the deferral of lost tax benefits that we believe are probable of recovery in future electric and natural gas distribution rates ($26 million).

Taxes Other Than Income Taxes

(Millions of Dollars)		**2010 Increase/(Decrease) as compared to 2009**
Connecticut Gross Earnings Tax	$	8.9
Property Taxes		12.5
Use Taxes		10.4
Other		0.7
	$	32.5

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to our capital programs. The Connecticut Gross Earnings Tax increased primarily as a result of an increase in the transmission segment revenues and an increase in distribution segment revenues primarily related to retail transmission and higher transition cost recoveries in 2010, as compared to 2009. The increase in use taxes was due primarily to the absence in 2010 of a Connecticut state use tax refund.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 231.1	$ 224.7	$ 6.4	2.8 %
Interest on RRBs	20.6	36.5	(15.9)	(43.6)
Other Interest	(14.4)	12.4	(26.8)	(a)
	$ 237.3	$ 273.6	$ (36.3)	(13.3)%

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense decreased in 2010, as compared to 2009, due primarily to the settlement of various state tax matters in the fourth quarter of 2010, which resulted in a reduction in Other Interest and lower Interest on RRBs resulting from lower principal balances outstanding, offset by higher Interest on Long-Term Debt as a result of $145 million in new long-term debt issuances in the first half of 2010 and $400 million in 2009, $150 million of which was issued by PSNH in December 2009.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 41.9	$ 37.8	$ 4.1	10.8%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($7 million), higher C&LM and EIA incentives ($3 million and $2 million, respectively), offset with lower investment and interest income ($4 million and $2 million, respectively).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 210.4	$ 179.9	$ 30.5	17.0%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impacts of the 2010 Healthcare Act ($30 million) and higher pre-tax earnings ($10 million), partially offset by lower impacts related to items that directly impact our tax return as a result of a regulatory activity ("flow-through") and other impacts ($5 million) and adjustments for prior years' taxes including adjustments to reconcile estimated taxes accrued to actual amounts reflected in our filed tax returns ($5 million).

Comparison of 2009 to 2008:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 5,439.4	$ 5,800.1	$ (360.7)	(6.2)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	2,629.6	2,996.2	(366.6)	(12.2)
Other Operating Expenses	1,001.2	1,021.7	(20.5)	(2.0)
Maintenance	234.2	254.0	(19.8)	(7.8)
Depreciation	309.6	278.6	31.0	11.1
Amortization of Regulatory Assets, Net	13.3	186.4	(173.1)	(92.9)
Amortization of Rate Reduction Bonds	217.9	204.9	13.0	6.3
Taxes Other Than Income Taxes	282.2	267.5	14.7	5.5
Total Operating Expenses	4,688.0	5,209.3	(521.3)	(10.0)
Operating Income	$ 751.4	$ 590.8	$ 160.6	27.2 %

Operating Revenues

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 4,358.4	$ 4,716.1	$ (357.7)	(7.6)%
Natural Gas Distribution	449.6	577.4	(127.8)	(22.1)
Total Distribution	4,808.0	5,293.5	(485.5)	(9.2)
Transmission	577.9	424.8	153.1	36.0
Total Regulated Companies	5,385.9	5,718.3	(332.4)	(5.8)
Competitive Businesses	81.3	114.1	(32.8)	(28.7)
Other and Eliminations	(27.8)	(32.3)	4.5	13.9
NU	$ 5,439.4	$ 5,800.1	$ (360.7)	(6.2)%

A summary of our retail electric sales and firm natural gas sales were as follows:

	For the Years Ended December 31,			
	2009	**2008**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	33,645	34,883	(1,238)	(3.5)%
Firm Natural Gas Sales in Million Cubic Feet	42,450	39,717	2,733	6.9%

Operating Revenues decreased in 2009, as compared to 2008, due primarily to lower distribution segment revenues ($485 million) as a result of the recovery of a lower level of electric and natural gas distribution fuel and other expenses passed through to customers through regulatory tracking mechanisms.

Electric distribution revenues decreased due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings ($395 million), partially offset by an increase in the component of revenues that impacts earnings ($37 million). The portion of electric distribution revenues that impacts earnings increased $37 million due primarily to higher CL&P and PSNH retail rates, partially offset by lower retail electric sales. Retail electric sales for the Regulated companies decreased 3.5 percent. Natural gas distribution revenues decreased $128 million due primarily to decreased recovery of fuel costs primarily as a result of lower prices, partially offset by higher sales volumes. Firm natural gas sales increased 6.9 percent in 2009 compared with 2008.

The $395 million decrease in electric distribution revenues that does not impact earnings consists of the portions of distribution revenues that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs ($356 million) and revenues that are eliminated in consolidation of the Regulated companies ($39 million). The distribution revenue tracking components decreased $356 million due primarily to lower recovery of generation service and related congestion charges ($331 million) and lower CL&P wholesale revenues as a result of decreased market revenue related to sales of IPP purchased generation output ($163 million), partially offset by higher retail transmission revenues ($104 million) mainly as a result of the higher 2009 retail rates. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008 and higher overall expenses. Competitive businesses' revenues decreased $33 million due primarily to lower Boulos revenues as a result of less work on transmission projects and a lower level of work in other areas.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2009, as compared to 2008, due primarily to the following:

(Millions of Dollars)	**2009 Increase/(Decrease) as compared to 2008**
Lower GSC supply costs and other purchased power costs, partially offset by an increase in deferred fuel costs at CL&P	$ (154.7)
Lower prices on purchased natural gas at Yankee Gas	(132.6)
An increased level of ES customer migration to third party electric suppliers and lower retail sales, partially offset by higher forward energy market prices at PSNH	(37.8)
Lower basic/default service supply costs at WMECO	(45.2)
Increased competitive businesses' expenses due primarily to lower Select Energy mark-to-market gains	3.7
	$ (366.6)

Other Operating Expenses

Other Operating Expenses decreased in 2009, as compared to 2008, due primarily to lower NU parent and other companies' expenses ($49 million) and lower competitive businesses' expenses ($39 million), partially offset by higher distribution and transmission segment expenses ($68 million).

NU parent and other companies' expenses were lower by $49 million in 2009 due primarily to the absence of the $49.5 million payment resulting from the settlement of litigation made in 2008 ($29.8 million after-tax). Competitive businesses' expenses were lower by $39 million due primarily to lower Boulos expenses as a result of a lower level of work.

Higher distribution and transmission segment expenses of $68 million were due primarily to higher electric distribution segment expenses ($49 million), higher expenses at Yankee Gas ($18 million), and higher transmission segment expenses ($15 million), partially offset by lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($8 million), and all other operating costs ($6 million). The higher operations expenses impacting earnings include higher uncollectible and pension expenses.

Maintenance

Maintenance decreased in 2009, as compared to 2008, due primarily to lower distribution segment expenses ($21 million), partially offset by higher transmission line expenses ($1 million). Distribution segment expenses were lower due primarily to lower repair and maintenance of distribution lines ($15 million), including lower storm-related expenses, lower equipment maintenance expenses ($4 million), and lower PSNH generation expenses ($3 million), partially offset by higher vegetation management expenses ($5 million).

Depreciation

Depreciation increased in 2009, as compared to 2008, due primarily to higher transmission segment ($23 million) and distribution segment ($11 million) plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net decreased $173 million in 2009, as compared to 2008, for the distribution segment due primarily to lower amortization at CL&P resulting from a lower recovery of stranded costs ($131 million) as a result of lower retail CTA revenues and higher transition costs, partially offset by higher amortization of the SBC balance ($15 million). The decreases for PSNH and WMECO are $39 million and $15 million, respectively.

Taxes Other Than Income Taxes

Taxes Other Than Income Taxes increased in 2009, as compared to 2008, due primarily to higher property taxes ($18 million) as a result of higher plant balances and increased municipal tax rates and higher payroll related taxes, partially offset by the resolution of various routine tax issues primarily surrounding sales and use tax amounts ($8 million).

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 224.7	$ 193.9	$ 30.8	15.9 %
Interest on RRBs	36.5	50.2	(13.7)	(27.3)
Other Interest	12.4	25.0	(12.6)	(50.4)
	$ 273.6	$ 269.1	$ 4.5	1.7 %

Interest Expense increased in 2009, as compared to 2008, due primarily to higher Interest on Long-Term Debt resulting from the issuance of new long-term debt in 2008 and 2009, partially offset by lower Interest on RRBs resulting from lower principal balances outstanding, and lower Other Interest mostly related to the resolution of various routine tax issues.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 37.8	$ 50.4	$ (12.6)	(25.0)%

Other Income, Net decreased in 2009, as compared to 2008, due primarily to lower AFUDC equity income ($20 million) as a result of lower eligible CWIP balances, the absence of interest income related to the federal tax settlement in 2008 ($10 million), and lower CL&P EIA incentives ($6 million), partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008 ($24 million).

Income Tax Expense

	For the Years Ended December 31,			
			Increase/	
(Millions of Dollars)	**2009**	**2008**	**(Decrease)**	**Percent**
Income Tax Expense	$ 179.9	$ 105.7	$ 74.2	70.2%

Income Tax Expense increased in 2009, as compared to 2008, due primarily to higher pre-tax earnings ($50 million), lower tax benefits associated with less capital expenditures ($10 million), lower federal and state tax credits ($4 million), and increases in allowance for uncollectible accounts reserves ($3 million).

Selected Consolidated Sales Statistics

	2010	2009	2008	2007	2006
Revenues: *(Thousands)*					
Regulated Companies:					
Residential	$ 2,336,078	$ 2,569,278	$ 2,525,635	$ 2,558,547	$ 2,409,414
Commercial	1,303,841	1,462,786	1,607,224	1,735,923	1,977,444
Industrial	268,598	297,854	399,753	412,381	589,742
Wholesale	506,475	445,261	545,127	392,675	388,635
Streetlighting and Railroads	42,387	33,035	38,522	45,880	52,853
Miscellaneous and Eliminations	(29,878)	128,118	24,673	84,043	133,925
Total Electric	4,427,501	4,936,332	5,140,934	5,229,449	5,552,013
Natural Gas	434,277	449,571	577,390	514,185	453,894
Total - Regulated Companies	$ 4,861,778	$ 5,385,903	$ 5,718,324	$ 5,743,634	$ 6,005,907
NU Enterprises:					
Retail	$ -	$ -	$ -	$ -	$ 583,829
Wholesale	24,633	30,009	31,882	25,992	20,163
Generation	-	-	-	-	258,178
Services	51,998	48,195	78,625	68,324	39,887
Miscellaneous and Eliminations	3,716	3,145	3,574	3,354	(243)
Total - NU Enterprises	$ 80,347	$ 81,349	$ 114,081	$ 97,670	$ 901,814
Other Miscellaneous and Eliminations	(43,958)	(27,822)	(32,310)	(19,078)	(30,034)
Total	$ 4,898,167	$ 5,439,430	$ 5,800,095	$ 5,822,226	$ 6,877,687
Regulated Companies - Sales: *(GWh)*					
Residential	14,913	14,412	14,509	15,051	14,652
Commercial	14,506	14,474	14,885	15,103	14,886
Industrial	4,481	4,423	5,149	5,635	5,750
Wholesale	3,423	4,183	3,576	3,855	8,777
Streetlighting and Railroads	330	336	340	353	332
Total	37,653	37,828	38,459	39,997	44,397
Regulated Companies - Customers: *(Average)*					
Residential	1,704,197	1,696,756	1,700,207	1,697,073	1,686,169
Commercial	192,266	189,265	190,067	189,727	188,281
Industrial	7,150	7,207	7,342	7,291	7,406
Streetlighting and Railroads*	6,292	7,548	4,605	3,855	3,873
Total Electric	1,909,905	1,900,776	1,902,221	1,897,946	1,885,729
Natural Gas	205,885	206,438	204,834	202,743	199,377
Total	2,115,790	2,107,214	2,107,055	2,100,689	2,085,106

*Customer counts were redefined with the implementation of a new customer service system (C2) completed in October 2008.

RESULTS OF OPERATIONS THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for CL&P included in this Annual Report on Form 10-K for the years ended December 31, 2010, 2009 and 2008:

Comparison of 2010 to 2009:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 2,999.1	$ 3,424.5	$ (425.4)	(12.4)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,253.3	1,690.7	(437.4)	(25.9)
Other Operating Expenses	524.3	571.0	(46.7)	(8.2)
Maintenance	96.5	117.8	(21.3)	(18.1)
Depreciation	172.2	186.9	(14.7)	(7.9)
Amortization of Regulatory Assets, Net	83.9	45.8	38.1	83.2
Amortization of Rate Reduction Bonds	167.0	156.0	11.0	7.1
Taxes Other Than Income Taxes	214.2	191.2	23.0	12.0
Total Operating Expenses	2,511.4	2,959.4	(448.0)	(15.1)
Operating Income	$ 487.7	$ 465.1	$ 22.6	4.9 %

Operating Revenues

CL&P's retail electric sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	22,666	22,266	400	1.8%

CL&P's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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Lower electric distribution revenues related to the portions that are included in DPUC approved tracking mechanisms that track and recover certain incurred costs that do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($421 million) and lower delivery-related FMCC revenues ($39 million). The lower GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in 2010, as compared to 2009. The lower delivery-related FMCC revenues were due primarily to changes in projections for certain delivery-related FMCC costs for 2010 that lowered the average rate charged to customers. These lower revenues were partially offset by higher retail transmission revenues ($37 million), higher transition cost recoveries ($27 million) and higher wholesale revenues ($4 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. In addition, transmission segment intracompany billings to the distribution segment that are eliminated in consolidation decreased by $66 million.

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The portion of electric distribution revenues that impacts earnings decreased $3 million due primarily to an unfavorable variance in demand and customer service charge components offset by a 1.8 percent increase in retail electric sales in 2010, as compared to 2009.

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Improved transmission segment revenues ($29 million) resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to the following:

(Millions of Dollars)		**2010 Increase/(Decrease) as compared to 2009**
GSC Supply Costs	$	(385.7)
Deferred Fuel Costs		(26.0)
Other Purchased Power Costs		(25.7)
	$	(437.4)

The decrease in GSC supply costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers in 2010, as compared to 2009. These GSC supply costs 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. The decrease in deferred fuel costs was due primarily to a smaller net overrecovery in 2010, as compared to 2009. These costs are included in DPUC approved tracking mechanisms and do not impact earnings.

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, as a result of lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($69 million) including RMR ($32 million) and retail transmission ($31 million), partially offset by higher distribution segment expenses ($20 million) mainly as a result of higher administrative and general expenses, including higher pension costs, and higher transmission segment expenses ($3 million).

Maintenance

Maintenance decreased in 2010, as compared to 2009, primarily related to the allowed regulatory deferral of approximately $32 million as a result of the June 30, 2010 rate case decision, of which $29.5 million was recognized as a deferral in maintenance expense. Partially offsetting this decrease was higher distribution overhead line expenses ($3 million) and higher distribution segment vegetation management costs ($3 million).

Depreciation

Depreciation decreased in 2010, as compared to 2009, due primarily to a lower depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased in 2010, as compared to 2009, due primarily to higher retail CTA revenue ($22 million) and lower CTA transition costs ($17 million). Partially offsetting these increases was a deferral of lost tax benefits related to the 2010 Healthcare Act that we believe are probable of recovery in future electric distribution rates ($15 million).

Taxes Other Than Income Taxes

(Millions of Dollars)		**2010 Increase/(Decrease) as compared to 2009**
Connecticut Gross Earnings Tax	$	9.8
Property Taxes		7.0
Use Taxes		5.9

Other		0.3
	$	23.0

The increase in Taxes Other Than Income Taxes was due primarily to an increase in the Connecticut Gross Earnings Tax due primarily to the increase in the transmission segment revenues and an increase in distribution segment revenues primarily related to retail transmission and higher transition cost recoveries in 2010, as compared to 2009. The increase in property taxes was a result of an increase in Property, Plant and Equipment related to CL&P's capital programs. The increase in use taxes was due to the absence in 2010 of a Connecticut state use tax refund.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 134.6	$ 133.4	$ 1.2	0.9 %
Interest on RRBs	7.5	19.1	(11.6)	(60.7)
Other Interest	(4.4)	3.3	(7.7)	(a)
	$ 137.7	$ 155.8	$ (18.1)	(11.6)%

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense decreased in 2010, as compared to 2009, due primarily to lower Interest on RRBs resulting from lower principal balances outstanding and the settlement of various state tax matters in the fourth quarter of 2010, which resulted in a reduction in Other Interest.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 26.7	$ 25.9	$ 0.8	3.1%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher C&LM and EIA incentives ($3 million and $3 million, respectively), offset by lower investment income ($3 million) and lower AFUDC related to equity funds ($1 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 132.4	$ 118.8	$ 13.6	11.4%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impacts of the 2010 Healthcare Act ($15 million) and higher pre-tax earnings ($5 million), partially offset by lower impacts related to flow-through items ($4 million) and adjustments to reconcile estimated taxes accrued to actual amounts reflected in our filed tax returns ($2 million).

Comparison of 2009 to 2008:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 3,424.5	$ 3,558.4	$ (133.9)	(3.8)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	1,690.7	1,845.4	(154.7)	(8.4)
Other Operating Expenses	571.0	557.6	13.4	2.4
Maintenance	117.8	130.4	(12.6)	(9.7)
Depreciation	186.9	162.6	24.3	14.9
Amortization of Regulatory Assets, Net	45.8	164.2	(118.4)	(72.1)
Amortization of Rate Reduction Bonds	156.0	145.6	10.4	7.1
Taxes Other Than Income Taxes	191.2	179.2	12.0	6.7
Total Operating Expenses	2,959.4	3,185.0	(225.6)	(7.1)
Operating Income	$ 465.1	$ 373.4	$ 91.7	24.6 %

Operating Revenues

CL&P's retail electric sales were as follows:

	For the Years Ended December 31,			
	2009	**2008**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	22,266	23,145	(879)	(3.8)%

Operating Revenues decreased in 2009, as compared to 2008, due to lower distribution segment revenues ($264 million), partially offset by higher transmission segment revenues ($130 million).

The distribution segment revenues decreased $264 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($289 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $25 million.

The $289 million decrease in distribution segment revenues that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs through CL&P's tariffs ($265 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($24 million). The distribution segment revenues included in DPUC approved tracking mechanisms decreased $265 million due primarily to a decrease in revenues associated with the recovery of GSC and supply-related FMCC ($184 million) and lower wholesale revenues as a result of decreased market revenue related to sales of CL&P's IPP purchased generation output to ISO-NE due to a decrease in the market price of energy ($163 million), partially offset by higher retail transmission revenues ($75 million). The lower GSC and supply-related FMCC revenue was due primarily to lower retail sales, lower customer rates resulting from lower average supply prices and additional customer migration to third-party suppliers in 2009, as compared to 2008. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of revenues that impacts earnings increased $25 million primarily as a result of rate changes, partially offset by lower retail sales. The 2009 retail sales, as compared to the same period in 2008, decreased 17.6 percent for the industrial, 2.9 percent for the commercial, and 0.7 percent for the residential classes. Total retail sales decreased overall by 3.8 percent.

Transmission segment revenues increased $130 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008 and higher overall expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2009, as compared to 2008, due primarily to lower GSC supply costs ($280 million) and other purchased power costs ($41 million), partially offset by an increase in deferred fuel costs ($165 million), all of which are included in DPUC approved tracking mechanisms. The $280 million decrease in GSC supply costs was due primarily to lower retail sales, lower average supply prices and additional customer migration to third-party suppliers. These GSC supply costs 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. The $165 million increase in deferred fuel costs was due primarily to the combined effect of the twelve months of 2008 net underrecovery of GSC and FMCC expenses, as compared to the twelve months of 2009 net overrecovery of these expenses.

Other Operating Expenses

Other Operating Expenses increased in 2009, as compared to 2008, as a result of higher distribution segment expenses ($36 million) due primarily to pension and expenses related to uncollectible receivable balances, and higher transmission segment expenses, which are tracked and recorded through FERC rate tariffs ($14 million), partially offset by lower costs that are recovered through distribution tracking mechanisms and have no earnings impact ($30 million), and lower transmission segment intracompany billing to the distribution segment that are eliminated in consolidation ($6 million).

Maintenance

Maintenance decreased in 2009, as compared to 2008, due primarily to lower repair and maintenance of distribution lines ($6 million), including lower storm expenses, lower distribution substation equipment expenses ($2 million), lower transmission segment expenses ($1 million), and lower transformer maintenance expenses ($1 million).

Depreciation

Depreciation increased in 2009, as compared to 2008, due primarily to higher utility plant balances resulting from completed construction projects placed into service in the transmission segment ($19 million) and the distribution segment ($5 million).

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net decreased in 2009, as compared to 2008, due primarily to lower amortization related to the recovery of stranded charges ($131 million) as a result of lower retail CTA revenue and higher transition costs, partially offset by higher amortization of the SBC balance ($15 million).

Taxes Other Than Income Taxes

Taxes Other Than Income Taxes increased in 2009, as compared to 2008, due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates ($10 million), higher gross earnings taxes ($4 million) recoverable in rates mainly as a result of higher transmission segment revenues that are subject to gross earnings tax, and higher payroll taxes ($2 million), partially offset by the resolution of various routine tax issues primarily surrounding sales and use tax amounts ($4 million).

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 133.4	$ 105.0	$ 28.4	27.0 %
Interest on RRBs	19.1	29.1	(10.0)	(34.4)
Other Interest	3.3	12.1	(8.8)	(72.7)
	$ 155.8	$ 146.2	$ 9.6	6.6 %

Interest Expense increased in 2009, as compared to 2008, due primarily to higher Interest on Long-Term Debt resulting from the $300 million debt issuance in May 2008 and the $250 million debt issuance in February 2009, partially offset by lower Other Interest mostly related to the resolution of various routine tax issues, and lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 25.9	$ 41.9	$ (16.0)	(38.2)%

Other Income, Net decreased in 2009, as compared to 2008, due primarily to lower AFUDC equity income ($18 million) as a result of lower eligible CWIP due to large transmission projects being completed and placed in-service in 2008 and lower capital expenditures in 2009, the absence in 2009 of interest income related to a federal tax settlement in 2008 ($6 million), and lower EIA incentives ($6 million), partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008 ($16 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 118.8	$ 77.9	$ 40.9	52.5%

Income Tax Expense increased due primarily to higher pre-tax earnings ($23 million), less tax benefits as a result of lower capital expenditures ($9 million), lower state tax credits ($3 million), and increases in allowance for doubtful accounts reserves ($4 million).

LIQUIDITY

CL&P had cash flows from operating activities in 2010 of $501.7 million, compared with operating cash flows of $482.2 million in 2009 and $267.3 million in 2008 (all amounts are net of RRB payments, which are included in financing activities). Improved cash flows in 2010 were attributed to a decrease in payments made related to CL&P's accounts payable in support of its operating activities. Improved cash flows were further due to increases in amortization on regulatory deferrals primarily attributable to 2009 activity within CL&P s CTA tracking mechanism where such costs exceeded revenues resulting in an unfavorable cash flow impact in 2009. Offsetting the improved cash flows was an increase in income tax payments of $29.1 million, which was the result of bonus depreciation tax deduction benefits received throughout 2009 not being extended for the full year of 2010 until the fourth quarter of 2010, as further described below.

On September 27, 2010, President Obama signed into law the Small Business Jobs and Credit Act of 2010, which extended bonus depreciation tax deduction through 2010. On December 17, 2010, President Obama signed into law the 2010 Tax Act, which, among other things, provides 100 percent bonus depreciation for tangible personal property placed in service after September 8, 2010, and through December 31, 2011. For tangible personal property placed in service after December 31, 2011, and through December 31, 2012, the 2010 Tax Act provides for 50 percent bonus depreciation. We project cash flows provided by operating activities at CL&P of between $600 million and $650 million in 2011, net of RRB payments, the increase over 2010 is due primarily to the cash flow benefits from the 2010 Tax Act.

On April 1, 2010, CL&P remarketed $62 million of tax-exempt PCRBs that were subject to a mandatory tender for purchase on April 1, 2010. The PCRBs, which mature on May 1, 2031, carry a coupon rate of 1.4 percent for a one-year period and are subject to a mandatory tender on April 1, 2011, at which time CL&P expects to remarket the bonds.

On September 24, 2010, CL&P, together with PSNH, WMECO, and Yankee Gas, entered into a three-year $400 million unsecured revolving credit facility, which expires on September 24, 2013. This facility replaced a five-year $400 million credit facility on similar terms and conditions that was scheduled to expire on November 6, 2010. CL&P is able to draw up to $300 million under this facility, subject to the $400 million maximum aggregate borrowing limit, either on a short-term or a long-term basis subject to regulatory approval. As of December 31, 2010, CL&P had no borrowings under this facility. Other financing activities for the year ended December 31, 2010 included $217.7 million in common dividends paid to NU parent, a $6.2 million increase in NU Money Pool borrowings, and $2.5 million in capital contributions from NU Parent. In 2011, CL&P has the mandatory tender of $62 million, which it plans to remarket, but does not have any long-term debt maturities until 2014, and there are no CL&P debt issuances planned for 2011.

On November 1, 2010, the DPUC approved CL&P's application requesting authority to issue up to $900 million in long-term debt through 2014. Proceeds will be used to refinance CL&P's short-term debt previously incurred in the ordinary course of business, to finance capital expenditures, to provide working capital and to pay issuance costs.

On December 30, 2010, CL&P made its final interest and principal payment on approximately $1.4 billion of rate reduction bonds that were issued in 2001. As a result, CL&P will no longer recover any payments from customers associated with these RRBs. A total of $203.2 million of principal and interest payments were made on these RRBs in 2010. The full amortization of these RRBs in 2010 will reduce CL&P s cash flows provided by operating activities in 2011, compared with previous years, but will have no material impact on CL&P s operating cash flows net of RRB payments.

On October 18, 2010, following the announcement of the proposed merger of NU and NSTAR, Moody's announced that it had reaffirmed the ratings and "stable" outlooks of CL&P and S&P announced that it had placed CL&P's ratings outlooks on credit watch with "positive" implications. On October 19, 2010, also due to the announcement of the proposed merger, Fitch announced that it had reaffirmed the ratings and "stable" outlooks of CL&P. On January 22, 2010, Fitch downgraded CL&P s preferred stock rating from BBB to BBB- as a result of revised guidelines for rating preferred stock and hybrid securities in general.

Cash capital expenditures included on the accompanying consolidated statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. CL&P's cash capital expenditures totaled $380.3 million in 2010, compared with $435.7 million in 2009. This decrease was primarily the result of lower transmission segment capital expenditures in 2010. Other investing activities in 2010 included a decrease in lendings to the NU Money Pool of $97.8 million.

Selected Consolidated Sales Statistics

	2010	2009	2008	2007	2006
Revenues: *(Thousands)*					
Residential	$ 1,597,754	$ 1,840,750	$ 1,811,845	$ 1,854,404	$ 1,709,700
Commercial	821,872	935,586	1,042,077	1,182,196	1,405,281
Industrial	144,463	151,839	190,723	208,087	380,479
Wholesale	441,660	386,034	484,843	347,514	318,958
Streetlighting and Railroads	32,084	22,638	28,710	35,370	42,099
Miscellaneous	(38,731)	87,691	163	54,246	123,294
Total	$ 2,999,102	$ 3,424,538	$ 3,558,361	$ 3,681,817	$ 3,979,811
Sales: *(GWh)*					
Residential	10,196	9,848	9,913	10,336	10,053
Commercial	9,716	9,705	9,993	10,128	9,995
Industrial	2,467	2,427	2,945	3,264	3,306
Wholesale	3,040	3,434	3,637	3,563	3,749
Streetlighting and Railroads	286	286	294	304	284
Total	25,705	25,700	26,782	27,595	27,387
Customers: *(Average)*					
Residential	1,096,576	1,093,229	1,094,991	1,091,799	1,084,937
Commercial	103,166	101,814	102,464	102,411	101,563
Industrial	3,359	3,381	3,613	3,743	3,848
Streetlighting and Railroads*	4,366	5,307	2,883	2,583	2,592
Total	1,207,467	1,203,731	1,203,951	1,200,536	1,192,940

*Customer counts were redefined with the implementation of a new customer service system (C2) completed in October 2008.

RESULTS OF OPERATIONS PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for PSNH included in this Annual Report on Form 10-K for the years ended December 31, 2010, 2009 and 2008:

Comparison of 2010 to 2009:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 1,033.4	$ 1,109.6	$ (76.2)	(6.9)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	363.1	520.5	(157.4)	(30.2)
Other Operating Expenses	230.2	239.7	(9.5)	(4.0)
Maintenance	82.4	87.0	(4.6)	(5.3)
Depreciation	67.2	62.0	5.2	8.4
Amortization of Regulatory Assets/(Liabilities), Net	11.2	(29.6)	40.8	(a)
Amortization of Rate Reduction Bonds	50.4	47.5	2.9	6.1
Taxes Other Than Income Taxes	52.7	47.9	4.8	10.0
Total Operating Expenses	857.2	975.0	(117.8)	(12.1)
Operating Income	$ 176.2	$ 134.6	$ 41.6	30.9 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

PSNH's retail electric sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	7,847	7,750	97	1.3%

PSNH's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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A $125 million decrease in distribution revenues that did not impact earnings. Of this decrease, $121 million related to lower recovery of purchased fuel and power costs mostly related to ES customer migration to third party electric suppliers, $19 million in lower transmission segment intracompany billings to the distribution segment that are eliminated in consolidation and $11 million related to lower wholesale revenues, offset by higher retail transmission revenues ($25 million) and an increase in the SCRC ($12 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers and undercollections to be recovered from customers in future periods.

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A $40 million increase in distribution segment revenues that impacts earnings primarily as a result of the retail rate increase effective July 1, 2010 and higher sales volume. Retail electric sales increased 1.3 percent in 2010 compared to 2009.

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A $9 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to an increased level of ES customer migration to third party electric suppliers, partially offset by higher retail sales.

Other Operating Expenses

Other Operating Expenses decreased in 2010, as compared to 2009, due primarily to lower distribution segment expenses ($7 million), mainly as a result of the rate case decision changing the collection of certain expenses to be tracked through the TCAM included in Amortization of Regulatory Assets/(Liabilities), Net in 2010.

Maintenance

Maintenance decreased in 2010, as compared to 2009, due primarily to lower boiler equipment and maintenance costs at the generation business ($12 million) as a result of insurance proceeds received in 2010 related to turbine damage, offset by higher distribution overhead line expenses related to storms in 2010 ($8 million).

Depreciation

Depreciation increased in 2010, as compared to 2009, due primarily to higher utility plant balances resulting from completed construction projects placed into service related to PSNH's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net increased in 2010, as compared to 2009, due primarily to increases in ES deferral ($42 million) and TCAM ($11 million) offset by decreases in the impact of the 2010 Healthcare Act related to the deferral of lost tax benefits that we believe are probable of recovery in future electric distribution rates ($7 million) and the NWPP accrual ($5 million)**.**

Taxes Other Than Income Taxes

(Millions of Dollars)		**2010 Increase/(Decrease) as compared to 2009**
Property Taxes	$	3.1
Use Taxes		1.5
Other		0.2
	$	4.8

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to PSNH's capital programs.

Interest Expense

	For the Years Ended December 31,						
(Millions of Dollars)		**2010**		**2009**		**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$	36.2	$	33.0	$	3.2	9.7 %
Interest on RRBs		9.7		13.1		(3.4)	(26.0)
Other Interest		1.2		0.4		0.8	(a)
	$	47.1	$	46.5	$	0.6	1.3 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Interest Expense increased in 2010, as compared to 2009, due primarily to higher Interest on Long-Term Debt resulting from the $150 million debt issuance in December 2009, offset by lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 11.7	$ 9.5	$ 2.2	23.2%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($7 million), offset by higher rental expenses ($3 million) and lower interest income ($1 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 50.8	$ 32.0	$ 18.8	58.8%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to higher pre-tax earnings ($13 million) and the impacts of the 2010 Healthcare Act ($7 million), partially offset by lower impacts related to flow-through items ($2 million).

Comparison of 2009 to 2008:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 1,109.6	$ 1,141.2	$ (31.6)	(2.8)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	520.5	558.3	(37.8)	(6.8)
Other Operating Expenses	239.7	215.5	24.2	11.2
Maintenance	87.0	90.9	(3.9)	(4.3)
Depreciation	62.0	56.3	5.7	10.1
Amortization of Regulatory Assets/(Liabilities), Net	(29.6)	9.3	(38.9)	(a)
Amortization of Rate Reduction Bonds	47.5	45.6	1.9	4.2
Taxes Other Than Income Taxes	47.9	42.4	5.5	13.0
Total Operating Expenses	975.0	1,018.3	(43.3)	(4.3)
Operating Income	$ 134.6	$ 122.9	$ 11.7	9.5 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

PSNH's retail electric sales were as follows:

	For the Years Ended December 31,			
	2009	**2008**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	7,750	7,926	(176)	(2.2)%

Operating Revenues decreased in 2009, as compared to 2008, due to lower distribution segment revenues ($46 million), partially offset by higher transmission segment revenues ($15 million).

The distribution segment revenues decreased $46 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($57 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $11 million primarily as a result of higher retail rates, partially offset by lower retail sales volumes. The 2009 retail sales, as compared to the same period in 2008, decreased 8.2 percent for the industrial, 1.5 percent for the commercial, and 0.2 percent for the residential classes. Total retail sales decreased overall by 2.2 percent.

The $57 million decrease in the portion of distribution segment revenues that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs through PSNH's tariffs ($47 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($9 million). The distribution segment revenues included in NHPUC approved tracking mechanisms decreased $47 million due primarily to lower purchased fuel and power costs ($99 million), partially offset by an increase in the SCRC ($27 million), higher retail transmission revenues ($14 million), higher wholesale revenue ($8 million), and higher NWPP renewable energy certificate revenues ($4 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $15 million due primarily to a higher transmission investment base and higher expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2009, as compared to 2008, due primarily to an increased level of migration of ES customers to competitive supply and lower retail sales, partially offset by higher forward energy market prices.

Other Operating Expenses

Other Operating Expenses increased in 2009, as compared to 2008, as a result of higher distribution segment expenses ($15 million), mainly as a result of higher administrative and general expenses, including higher pension and medical costs, and higher expenses related to uncollectible receivable balances, and higher retail transmission expenses that are recovered through distribution tracking mechanisms and have no earnings impact ($10 million).

Maintenance

Maintenance decreased in 2009, as compared to 2008, due primarily to lower repair and maintenance of distribution lines ($7 million), including lower storm costs, lower generation expenses primarily as a result of lower maintenance outage expenses at Merrimack Station ($2 million) and hydro expenses incurred in 2008 primarily as a result of two major dam resurfacing projects ($1 million), partially offset by higher vegetation management expenses ($5 million).

Depreciation

Depreciation increased in 2009, as compared to 2008, due primarily to higher utility plant balances resulting from completed construction projects placed into service in the distribution segment ($3 million) and the transmission segment ($2 million).

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net decreased in 2009, as compared to 2008, due primarily to a decrease in net deferrals associated with the ES and TCAM tracking mechanisms, partially offset by an increase in net deferrals associated with the SCRC tracking mechanism.

Taxes Other Than Income Taxes

Taxes Other Than Income Taxes increased in 2009, as compared to 2008, due primarily to higher property taxes as a result of higher net plant balances and increased local municipal tax rates ($7 million), partially offset by lower sales taxes as a result of the resolution of various routine tax issues ($1 million).

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 33.0	$ 32.7	$ 0.3	0.9 %
Interest on RRBs	13.1	16.0	(2.9)	(18.1)
Other Interest	0.4	1.5	(1.1)	(73.3)
	$ 46.5	$ 50.2	$ (3.7)	(7.4)%

Interest Expense decreased in 2009, as compared to 2008, due primarily to lower Interest on RRBs resulting from lower principal balances outstanding and lower Other Interest mostly related to the resolution of various routine tax issues.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 9.5	$ 7.3	$ 2.2	30.1%

Other Income, Net increased in 2009, as compared to 2008, due primarily to higher investment income related to improved results from the NU supplemental benefit trust and the absence of other-than-temporary impairments recorded in 2008, and higher interest income related to the return on the December 2008 ice storm, partially offset by the absence in 2009 of interest income related to a federal tax settlement in 2008 and lower AFUDC equity income due to higher short-term debt, which resulted in a lower rate based on borrowing costs.

Income Tax Expense

	For the Years Ended December 31,			
			Increase/	
(Millions of Dollars)	**2009**	**2008**	**(Decrease)**	**Percent**
Income Tax Expense	$ 32.0	$ 22.0	$ 10.0	45.5%

Income tax expense increased in 2009, as compared to 2008, due primarily to higher pre-tax earnings ($6 million) and less favorable depreciation deduction adjustments ($2 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in 2010 of $145.4 million, compared with operating cash flows of $58.2 million in 2009 and $116.4 million in 2008, all amounts are net of RRB payments included in financing activities on the accompanying consolidated statements of cash flows. The improved cash flows were due primarily to the absence in 2010 of costs related to the major storm in December 2008 that were paid in the first quarter of 2009, a decrease in Fuel, Materials and Supplies attributable to a $31.8 million reduction in coal inventory levels in 2010 at the generation business as ordered by the NHPUC, and increases in amortization on regulatory deferrals primarily attributable to 2009 activity within PSNH s ES tracking mechanism where such costs exceeded revenues resulting in an unfavorable cash flow impact in 2009. Offsetting these favorable cash flow impacts was a $45 million contribution made in the third quarter of 2010 into the NU Pension Plan and payments made relating to the February 2010 severe storm for which the costs were deferred. PSNH expects to develop a recovery plan for these 2010 storm costs, net of any insurance payments PSNH would receive, through a previously agreed upon cooperative effort between PSNH, the NHPUC Staff, and the Office of Consumer Advocate as outlined in the joint settlement agreement of PSNH's distribution rate case that was effective July 1, 2010.

Selected Consolidated Sales Statistics

	2010	2009	2008	2007	2006
Revenues: *(Thousands)*					
Residential	$ 529,992	$ 506,725	$ 472,486	$ 457,616	$ 467,517
Commercial	360,373	407,743	431,461	413,196	439,828
Industrial	90,243	112,460	169,785	156,258	166,132
Wholesale	33,003	41,193	35,935	25,030	52,255
Streetlighting and Railroads	6,669	6,331	6,515	6,018	5,729
Miscellaneous	13,159	35,139	25,020	24,954	9,439
Total	$ 1,033,439	$ 1,109,591	$ 1,141,202	$ 1,083,072	$ 1,140,900
Sales: *(GWh)*					
Residential	3,175	3,097	3,105	3,176	3,087
Commercial	3,309	3,311	3,361	3,403	3,342
Industrial	1,339	1,318	1,435	1,528	1,582
Wholesale	206	562	(243)	105	985
Streetlighting and Railroads	24	24	25	24	23
Total	8,053	8,312	7,683	8,236	9,019
Customers: *(Average)*					
Residential	420,481	417,670	418,107	417,420	413,980
Commercial	71,746	70,984	70,807	70,341	69,528
Industrial	3,088	3,134	2,978	2,770	2,761
Streetlighting and Railroads	1,442	1,438	970	602	592
Total	496,757	493,226	492,862	491,133	486,861

RESULTS OF OPERATIONS WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

The following table provides the amounts and variances in operating revenues and expense line items for the consolidated statements of income for WMECO included in this Annual Report on Form 10-K for the years ended December 31, 2010, 2009 and 2008:

Comparison of 2010 to 2009:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 395.2	$ 402.4	$ (7.2)	(1.8)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	157.3	192.2	(34.9)	(18.2)
Other Operating Expenses	102.1	85.6	16.5	19.3
Maintenance	19.2	17.9	1.3	7.3
Depreciation	23.6	22.5	1.1	4.9
Amortization of Regulatory Assets/(Liabilities), Net	2.3	(3.0)	5.3	(a)
Amortization of Rate Reduction Bonds	15.5	14.5	1.0	6.9
Taxes Other Than Income Taxes	16.5	14.1	2.4	17.0
Total Operating Expenses	336.5	343.8	(7.3)	(2.1)
Operating Income	$ 58.7	$ 58.6	$ 0.1	0.2 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

WMECO's retail electric sales were as follows:

	For the Years Ended December 31,			
	2010	**2009**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	3,732	3,644	88	2.4%

WMECO's Operating Revenues decreased in 2010, as compared to 2009, due primarily to:

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A $20 million decrease related to distribution revenues that did not impact earnings and was included in DPU approved tracking mechanisms that track the recovery of certain incurred costs through WMECO's tariffs. Included in these costs are a decrease of $31 million related to a lower recovery of energy supply costs and a decrease of $7 million related to transmission segment intracompany billings to the distribution segment that are eliminated in consolidation. Offsetting these decreases were increases in transition cost recoveries, C&LM collections and retail transmission revenues ($8 million, $5 million and $4 million, respectively). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections to be recovered from customers in future periods.

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The portion of electric distribution revenues that impacts earnings increased $2 million due primarily to a 2.4 percent increase in retail electric sales in 2010, as compared to 2009.

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A $10 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the return of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2010, as compared to 2009, due primarily to lower Basic/Default service supply costs. The basic/default service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process. These costs decreased due primarily to lower supplier contract rates.

Other Operating Expenses

Other Operating Expenses increased in 2010, as compared to 2009, as a result of higher distribution segment expenses ($9 million) resulting from higher administrative and general expenses, including pension costs, higher costs that are recovered through distribution tracking mechanisms and have no earnings impact primarily related to an increase in C&LM expenses attributable to the Massachusetts Green Communities Act ($6 million), and higher transmission segment expenses ($1 million).

Maintenance

Maintenance increased in 2010, as compared to 2009, due primarily to higher distribution overhead line expenses.

Depreciation

Depreciation increased in 2010, as compared to 2009, due primarily to higher utility plant balances resulting from completed construction projects placed into service related to WMECO's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net, increased in 2010, as compared to 2009, due primarily to the recovery of the previously deferred unrecovered stranded generation costs ($11 million), offset by a deferral of lost tax benefits related to the 2010 Healthcare Act that we believe are probable of recovery in future electric distribution rates ($4 million).

Taxes Other Than Income Taxes

(Millions of Dollars)	**2010 Increase/(Decrease) as compared to 2009**
Property Taxes	$ 1.5
Sales Taxes	0.6
Other	0.3
	$ 2.4

The increase in Taxes Other Than Income Taxes was due primarily to an increase in property taxes as a result of an increase in Property, Plant and Equipment related to WMECO's capital programs.

Interest Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 18.0	$ 14.1	$ 3.9	27.7 %
Interest on RRBs	3.4	4.3	(0.9)	(20.9)
Other Interest	0.4	0.9	(0.5)	(55.6)
	$ 21.8	$ 19.3	$ 2.5	13.0 %

Interest Expense increased in 2010, as compared to 2009, due primarily to higher Interest on Long-Term Debt resulting from the $95 million debt issuance in March 2010, offset by lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Other Income, Net	$ 2.6	$ 1.8	$ 0.8	44.4%

Other Income, Net increased in 2010, as compared to 2009, due primarily to higher AFUDC related to equity funds ($1 million) and higher interest income ($1 million), offset by lower investment income ($1 million).

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2010**	**2009**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 16.3	$ 14.9	$ 1.4	9.4%

Income Tax Expense increased in 2010, as compared to 2009, due primarily to the impacts of the 2010 Healthcare Act ($3 million), partially offset by lower pre-tax earnings and other impacts ($2 million).

Comparison of 2009 to 2008:

	Revenues and Expenses For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 402.4	$ 441.5	$ (39.1)	(8.9)%
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	192.2	237.4	(45.2)	(19.0)
Other Operating Expenses	85.6	77.0	8.6	11.2
Maintenance	17.9	20.7	(2.8)	(13.5)
Depreciation	22.5	21.0	1.5	7.1
Amortization of Regulatory Assets/(Liabilities), Net	(3.0)	12.4	(15.4)	(a)
Amortization of Rate Reduction Bonds	14.5	13.6	0.9	6.6
Taxes Other Than Income Taxes	14.1	12.9	1.2	9.3
Total Operating Expenses	343.8	395.0	(51.2)	(13.0)
Operating Income	$ 58.6	$ 46.5	$ 12.1	26.0 %

(a)

Percent greater than 100 percent not shown as it is not meaningful.

Operating Revenues

WMECO's retail electric sales were as follows:

	For the Years Ended December 31,			
	2009	**2008**	**Increase/ (Decrease)**	**Percent**
Retail Electric Sales in GWh	3,644	3,829	(185)	(4.8)%

Operating Revenues decreased in 2009, as compared to 2008, due to lower distribution segment revenues ($47 million), partially offset by higher transmission segment revenues ($8 million).

The distribution segment revenues decreased $47 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings ($49 million). These revenues do not impact earnings, primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation. The portion of revenues that impacts earnings increased $1 million.

The $49 million distribution segment revenues decrease that does not impact earnings was due primarily to a decrease in the portions of retail revenues that are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs through WMECO's tariffs ($44 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation ($5 million). The distribution revenues included in DPU approved tracking mechanisms decreased $44 million due primarily to lower energy supply costs ($48 million), lower transition cost recoveries ($10 million), and lower wholesale revenues ($5 million), partially offset by higher retail transmission revenues ($15 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The 2009 retail sales, as compared to the same period in 2008, decreased 11.7 percent for the industrial, 4.8 percent for the commercial, and 1.6 percent for the residential classes. Total retail sales decreased overall by 4.8 percent.

Transmission segment revenues increased $8 million due primarily to a higher transmission investment base and higher expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased in 2009, as compared to 2008, due primarily to lower Basic/Default Service supply costs ($47 million) and lower other purchased power costs ($2 million), partially offset by higher deferral of excess Basic/Default Service revenue over Basic/Default Service expense ($4 million). The Basic/Default Service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process. These costs decreased as a result of lower supplier contract rates and reduced load volumes. To the extent that these costs do not match the revenues collected from customers, the DPU allows the difference to be deferred for future collection or refund. Lower other purchased power costs are due primarily to a decrease in costs associated with customer generation and IPPs.

Other Operating Expenses

Other Operating Expenses increased in 2009, as compared to 2008, as a result of higher retail transmission and other costs that are recovered through distribution tracking mechanisms and have no earnings impact ($11 million), partially offset by lower distribution segment expenses ($2 million) mainly as a result of lower administrative and general expenses.

Maintenance

Maintenance decreased in 2009, as compared to 2008, due primarily to lower repair and maintenance of distribution lines including lower storm expenses and lower vegetation management expense.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net decreased in 2009, as compared to 2008, due primarily to the deferral of allowed transition costs that are in excess of transition revenues, resulting from a decrease in the transition cost portion of the rate and lower IPP revenue than previous years.

Taxes Other Than Income Taxes

Taxes Other Than Income Taxes increased in 2009, as compared to 2008, due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates.

Income Tax Expense

	For the Years Ended December 31,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (Decrease)**	**Percent**
Income Tax Expense	$ 14.9	$ 10.5	$ 4.4	41.9%

Income tax expense increased due primarily to higher pre-tax earnings.

LIQUIDITY

WMECO had cash flows provided by operating activities in 2010 of $50.5 million, compared with operating cash flows of $47.7 million in 2009 and $53.9 million in 2008, all amounts are net of RRB payments included in financing activities on the accompanying consolidated statements of cash flows. The increase in cash flows was primarily due to the absence in 2010 of costs related to the major storm in December 2008 that were paid in the first quarter of 2009. These costs, as well as storm costs in 2010, were deferred and in accordance with WMECO s February 1, 2011 distribution rate case decision will be recovered from customers over five years as part of WMECO's storm reserve. The deferral of the 2010 significant storms cost created an unfavorable cash flow impact to WMECO's regulatory underrecoveries of approximately $6.1 million.

Offsetting the improved cash flows was an increase in income tax payments of $14.1 million, which was the result of bonus depreciation tax deduction benefits received throughout 2009 not being extended for the full year of 2010 until the fourth quarter of 2010.

Selected Consolidated Sales Statistics

	2010	2009	2008	2007	2006
Revenues: *(Thousands)*					
Residential	$ 208,332	$ 221,803	$ 241,303	$ 246,526	$ 232,197
Commercial	121,597	119,457	133,686	140,531	132,336
Industrial	33,892	33,555	39,245	48,036	43,131
Other Utilities	31,812	18,034	24,349	20,131	17,421
Streetlighting and Railroads	3,633	4,066	3,297	4,492	5,025
Miscellaneous	(4,105)	5,498	(353)	5,029	1,399
Total	$ 395,161	$ 402,413	$ 441,527	$ 464,745	$ 431,509
Sales: *(GWh)*					
Residential	1,542	1,467	1,491	1,539	1,511
Commercial	1,496	1,474	1,547	1,589	1,574
Industrial	675	679	769	842	862
Other Utilities	177	187	179	178	189
Streetlighting and Railroads	20	24	22	25	25
Total	3,910	3,831	4,008	4,173	4,161
Customers: *(Average)*					
Residential	187,140	185,856	187,109	187,854	187,252
Commercial	17,475	16,587	16,916	17,096	17,310
Industrial	703	692	751	777	798
Streetlighting and Railroads	516	835	785	703	705
Total	205,834	203,970	205,561	206,430	206,065

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.

Select Energy's Wholesale Portfolio: The remaining wholesale portfolio held by Select Energy includes contracts that are market-risk sensitive, including a wholesale energy sales contract through 2013 with an agency comprised of municipalities with approximately 0.3 million remaining MWh of supply contract volumes, net of related sales volumes. Select Energy also has a non-derivative energy contract that expires in mid-2012 to purchase output from a generation facility, which is also exposed to market price volatility.

As Select Energy's contract volumes are winding down, and as the wholesale energy sales contract is substantially hedged against price risks, we have limited exposure to commodity price risks. We have not entered into any energy contracts for trading purposes. For Select Energy's wholesale energy portfolio derivatives, we utilize the sensitivity analysis methodology to disclose quantitative information for our commodity price risks. Sensitivity analysis provides a presentation of the potential loss of future pre-tax earnings and fair values from our market risk-sensitive contracts due to one or more hypothetical changes in commodity price components, or other similar price changes. As of December 31, 2010, assuming hypothetical 30 percent increases and decreases in forward energy, capacity and ancillary market prices, the nominal adjusted impact on pre-tax earnings would be $0.1 million and $(0.8) million, respectively.

The impact of a change in electricity prices on wholesale derivative transactions as of December 31, 2010 are not necessarily representative of the results that will be realized if such a change were to occur. Energy, capacity and ancillaries have different market volatilities. The method we use to determine the fair value of these contracts includes discounting expected future cash flows using a LIBOR swap curve. As such, the wholesale portfolio is also exposed to interest rate volatility. This exposure is not modeled in sensitivity analyses, and we do not believe that such exposure is material.

Other Risk Management Activities

We have implemented an Enterprise Risk Management methodology for identifying the principal risks of the Company. Enterprise Risk Management involves the application of a well-defined, enterprise-wide methodology that enables our Risk and Capital Committee, comprised of our senior officers, to oversee the identification, management and reporting of the principal risks of the business. 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 condition, results of operations or cash flows. The findings of this process are periodically discussed with our Board of Trustees.

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, 2010, approximately 93 percent (87 percent including the long-term debt subject to the fixed-to-floating interest rate swap as variable rate long-term debt) 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 rate, annual interest expense would have increased by a pre-tax amount of $3.3 million. As of December 31, 2010, we maintained a fixed-to-floating interest rate swap at NU parent associated with $263 million of its fixed-rate long-term debt.

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 suppliers that include IPPs, industrial companies, 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 maintain an oversight group that monitors contracting risks, including credit risk. As of December 31, 2010, our Regulated companies neither held cash collateral nor deposited cash collateral with counterparties. NU parent provides standby LOCs for the benefit of its subsidiaries under its revolving credit agreement. PSNH posts such LOCs as collateral with counterparties and ISO-NE. For further information, see Note 12E, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements.

Select Energy has also established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require collateral under certain circumstances (including cash in advance, LOCs, and parent guarantees), and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty in the event of default. This evaluation results in establishing credit limits prior to Select Energy entering into energy contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may impact Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by

changes to economic, regulatory or other conditions. For further information, see Note 1H, " Summary of Significant Accounting Policies - Special Deposits and Counterparty Deposits," to the consolidated financial statements.

Additional quantitative and qualitative disclosures about market risk are set forth in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, included in this Annual Report on Form 10-K.

Item 8.

Financial Statements and Supplementary Data

Company Report on Internal Controls Over Financial Reporting

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 generally accepted accounting principles. 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* 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, 2010.

February 25, 2011

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 and consolidated statements of capitalization of Northeast Utilities and subsidiaries (the "Company") as of December 31, 2010 and 2009, 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, 2010. Our audits also included the consolidated 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, 2010, based on criteria established in *Internal Control Integrated Framework* 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 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, and 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated 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, 2010, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

February 25, 2011

NORTHEAST UTILITIES AND
SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2010	2009
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 23,395	$ 26,952
Receivables, Net	523,644	512,770
Unbilled Revenues	208,834	229,326
Taxes Receivable	89,638	27,600
Fuel, Materials and Supplies	244,043	277,085
Marketable Securities	78,306	66,236
Derivative Assets	17,287	31,785
Prepayments and Other Current Assets	132,595	96,100
Total Current Assets	1,317,742	1,267,854
Property, Plant and Equipment, Net	9,567,726	8,839,965
Deferred Debits and Other Assets:		
Regulatory Assets	2,995,279	3,244,931
Goodwill	287,591	287,591
Marketable Securities	51,201	54,905
Derivative Assets	123,242	189,751
Other Long-Term Assets	179,261	172,682
Total Deferred Debits and Other Assets	3,636,574	3,949,860
Total Assets	$ 14,522,042	$ 14,057,679

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2010	2009
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 267,000	$ 100,313
Long-Term Debt - Current Portion	66,286	66,286
Accounts Payable	417,285	457,582
Obligations to Third Party Suppliers	74,659	44,978
Accrued Taxes	107,067	50,246
Accrued Interest	74,740	83,763
Derivative Liabilities	71,501	37,617
Other Current Liabilities	159,537	138,627
Total Current Liabilities	1,238,075	979,412
Rate Reduction Bonds	181,572	442,436
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,693,860	1,380,143
Regulatory Liabilities	439,058	485,706
Derivative Liabilities	909,668	955,646
Accrued Pension	802,195	781,431
Other Long-Term Liabilities	695,915	845,868
Total Deferred Credits and Other Liabilities	4,540,696	4,448,794
Capitalization:		
Long-Term Debt	4,632,866	4,492,935
Noncontrolling Interest in Consolidated Subsidiary:		
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Equity:		
Common Shareholders' Equity:		
Common Shares	978,909	977,276
Capital Surplus, Paid In	1,777,592	1,762,097
Deferred Contribution Plan	-	(2,944)
Retained Earnings	1,452,777	1,246,543
Accumulated Other Comprehensive Loss	(43,370)	(43,467)
Treasury Stock	(354,732)	(361,603)
Common Shareholders' Equity	3,811,176	3,577,902
Noncontrolling Interests	1,457	-

Total Equity		3,812,633		3,577,902
Total Capitalization		8,561,699		8,187,037
Commitments and Contingencies (Note 12)				
Total Liabilities and Capitalization	$	14,522,042	$	14,057,679

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars, Except Share Information)	2010	2009	2008
Operating Revenues	$ 4,898,167	$ 5,439,430	$ 5,800,095
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	1,985,634	2,629,619	2,996,180
Other Operating Expenses	958,417	1,001,190	1,021,704
Maintenance	210,283	234,173	254,038
Depreciation	300,737	309,618	278,588
Amortization of Regulatory Assets, Net	95,593	13,315	186,396
Amortization of Rate Reduction Bonds	232,871	217,941	204,859
Taxes Other Than Income Taxes	314,741	282,199	267,565
Total Operating Expenses	4,098,276	4,688,055	5,209,330
Operating Income	799,891	751,375	590,765
Interest Expense:			
Interest on Long-Term Debt	231,089	224,712	193,883
Interest on Rate Reduction Bonds	20,573	36,524	50,231
Other Interest (Note 11)	(14,371)	12,401	25,031
Interest Expense	237,291	273,637	269,145
Other Income, Net	41,916	37,801	50,428
Income Before Income Tax Expense	604,516	515,539	372,048
Income Tax Expense	210,409	179,947	105,661
Net Income	394,107	335,592	266,387
Net Income Attributable to Noncontrolling Interests	6,158	5,559	5,559
Net Income Attributable to Controlling Interests	$ 387,949	$ 330,033	$ 260,828
Basic Earnings Per Common Share	$ 2.20	$ 1.91	$ 1.68
Diluted Earnings Per Common Share	$ 2.19	$ 1.91	$ 1.67
Weighted Average Common Shares Outstanding:			
Basic	176,636,086	172,567,928	155,531,846
Diluted	176,885,387	172,717,246	155,999,240

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2010	2009	2008
Net Income	$ 394,107	$ 335,592	$ 266,387
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	200	200	(6,909)
Changes in Unrealized Gains/(Losses) on Other Securities	402	(976)	(1,669)
Change in Funded Status of Pension, SERP and Other Postretirement Benefit Plans	(505)	(5,426)	(38,046)
Other Comprehensive Income/(Loss), Net of Tax	97	(6,202)	(46,624)
Comprehensive Income Attributable to Noncontrolling Interests	(6,158)	(5,559)	(5,559)
Comprehensive Income Attributable to Controlling Interests	$ 388,046	$ 323,831	$ 214,204

The accompanying notes are an integral part of these consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON
SHAREHOLDERS' EQUITY

	Common Shares	Capital	Deferred	Accumulated Other	Total Common