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** 04-1961130
(a Massachusetts corporation)
One Federal Street
Building 111-4
Springfield, Massachusetts 01105
Telephone: (413) 785-5871

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
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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.

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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.

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.

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.

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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

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 I (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

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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.

<u>Forecasted Expenses and Expected Contributions</u>: 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.

<u>Sensitivity Analysis</u>: 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

<u>Health Care Cost</u>: 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:

.

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).

<u>Comparison of 2009 to 2008</u>:

	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,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (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,			
(Millions of Dollars)	**2009**	**2008**	**Increase/ (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.

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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

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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

(Thousands of Dollars)	As of December 31, 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

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

(Thousands of Dollars, Except Share Information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Common Shareholders' Equity
Balance as of January 1, 2008	155,079,770	$ 879,623	$ 1,465,946	$ (26,352)	$ 946,792	$ 9,359	$ (361,533)	$ 2,913,835
Net Income					266,387			266,387
Dividends on Common Shares - $0.825 Per Share					(129,026)			(129,026)
Issuance of Common Shares, $5 Par Value	287,581	1,438	4,086					5,524
Dividends on Preferred Stock					(5,559)			(5,559)
Allocation of Benefits ESOP	469,601		865	10,871				11,736
Change in Restricted Shares, Net	(2,591)		2,436				(70)	2,366
Tax Deduction for Stock Options Exercised and Employee Stock Purchase Plan Disqualifying Dispositions			1,622					1,622
Capital Stock Expenses, Net			51					51
Other Comprehensive Loss						(46,624)		(46,624)
Balance as of December 31, 2008	155,834,361	881,061	1,475,006	(15,481)	1,078,594	(37,265)	(361,603)	3,020,312
Adoption of Accounting Guidance for Other-Than-Temporary Impairments (Note 1K)					728	(728)		-
Net Income					335,592			335,592

Dividends on Common Shares - $0.95 Per Share					(162,812)			(162,812)
Issuance of Common Shares, $5 Par Value	19,242,939	96,215	293,502					389,717
Dividends on Preferred Stock					(5,559)			(5,559)
Allocation of Benefits ESOP	542,724		(98)	12,537				12,439
Change in Restricted Shares, Net			5,303					5,303
Tax Deduction for Stock Options Exercised and Employee Stock Purchase Plan Disqualifying Dispositions			913					913
Capital Stock Expenses, Net			(12,529)					(12,529)
Other Comprehensive Loss						(5,474)		(5,474)
Balance as of December 31, 2009	175,620,024	977,276	1,762,097	(2,944)	1,246,543	(43,467)	(361,603)	3,577,902
Net Income					394,107			394,107
Dividends on Common Shares - $1.025 Per Share					(181,715)			(181,715)
Issuance of Common Shares, $5 Par Value	326,526	1,633	5,745					7,378
Dividends on Preferred Stock					(6,101)			(6,101)
Net Income Attributable to Noncontrolling Interests					(57)			(57)
Allocation of Benefits ESOP	127,054		439	2,944				3,383
ESOP Benefits from Treasury Shares			3,856				(3,856)	-
Change in Restricted Shares, Net			4,868					4,868
Change in Treasury Stock	374,477						10,727	10,727

Tax Deduction for Stock Options Exercised and Employee Stock Purchase Plan Disqualifying Dispositions			866					866
Capital Stock Expenses, Net			(279)					(279)
Other Comprehensive Income						97		97
Balance as of December 31, 2010	176,448,081	$ 978,909	$ 1,777,592	$ -	$ 1,452,777	$ (43,370)	$ (354,732)	$ 3,811,176

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2010	2009	2008
Operating Activities:			
Net Income	$ 394,107	$ 335,592	$ 266,387
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:			
Bad Debt Expense	31,352	53,947	28,573
Depreciation	300,737	309,618	278,588
Deferred Income Taxes	210,939	125,890	86,810
Pension and PBOP Expense, Net of PBOP Contributions	58,228	21,572	(3,839)
Pension Contribution	(45,000)	-	-
Regulatory Overrecoveries/(Underrecoveries), Net	20,750	37,868	(185,252)
Amortization of Regulatory Assets, Net	95,593	13,315	186,396
Amortization of Rate Reduction Bonds	232,871	217,941	204,859
Derivative Assets and Liabilities	(11,812)	(18,798)	(37,052)
Other	(72,151)	(26,003)	(51,787)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(51,285)	91,081	(141,879)
Investments in Securitizable Assets	-	-	(25,787)
Fuel, Materials and Supplies	38,126	25,957	(74,531)
Taxes Receivable/Accrued	(82,103)	16,194	63,251
Accounts Payable	(44,355)	(208,180)	72,791
Other Current Assets and Liabilities	17,466	(6,876)	(12,551)
Net Cash Flows Provided by Operating Activities	1,093,463	989,118	654,977
Investing Activities:			
Investments in Property, Plant and Equipment	(954,472)	(908,146)	(1,255,407)
Proceeds from Sales of Marketable Securities	174,865	208,947	259,361
Purchases of Marketable Securities	(177,204)	(211,243)	(262,357)
Other Investing Activities	(1,157)	7,963	5,046
Net Cash Flows Used in Investing Activities	(957,968)	(902,479)	(1,253,357)
Financing Activities:			
Issuance of Common Shares	-	383,295	-
Cash Dividends on Common Shares	(180,542)	(162,381)	(129,077)

Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
Increase/(Decrease) in Short-Term Debt	166,687	(518,584)	539,897
Issuance of Long-Term Debt	145,000	462,000	760,000
Retirements of Long-Term Debt	(4,286)	(54,286)	(261,286)
Retirements of Rate Reduction Bonds	(260,864)	(244,075)	(230,925)
Other Financing Activities	512	(9,913)	42
Net Cash Flows (Used In)/Provided by Financing Activities	(139,052)	(149,503)	673,092
Net (Decrease)/Increase in Cash and Cash Equivalents	(3,557)	(62,864)	74,712
Cash and Cash Equivalents - Beginning of Year	26,952	89,816	15,104
Cash and Cash Equivalents - End of Year	$ 23,395	$ 26,952	$ 89,816

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars)		As of December 31, 2010	2009
		$	$
Common Shareholders Equity		3,811,176	3,577,902
Noncontrolling Interests		1,457	-
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption -			
$50 par value - authorized 9,000,000 shares in 2010 and 2009;			
2,324,000 shares outstanding in 2010 and 2009;			
Dividend rates of $1.90 to $3.24;			
Current redemption prices of $50.50 to $54.00		116,200	116,200
Long-Term Debt:			
First Mortgage Bonds:			
Final Maturity	Interest Rates		
2010-2012	7.19%	8,571	12,857
2014-2018	4.80% to 6.90%	1,205,000	1,205,000
2019-2024	4.50% to 8.48%	659,845	609,845
2034-2037	5.35% to 6.375%	830,000	830,000
Total First Mortgage Bonds		2,703,416	2,657,702
Other Long-Term Debt:			
Pollution Control Notes:			
2016-2018	5.90%	25,400	25,400
2021-2022	Variable Rate and 4.75% to 6.00%	428,285	428,285
2028	5.85% to 5.95%	369,300	369,300
2031 (Note 9)	1.40%	62,000	62,000
Other:			
2012-2020	5.00% to 7.25%	713,000	618,000
2034-2037	5.90% to 6.70%	90,000	90,000
Total Pollution Control Notes and Other		1,687,985	1,592,985
Total First Mortgage Bonds, Pollution Control Notes and Other		4,391,401	4,250,687
Fees and Interest Due for Spent Nuclear Fuel Disposal Costs		301,042	300,647
Change in Fair Value Resulting from Interest Rate Hedge Instrument		11,859	13,258
Unamortized Premium and Discount, Net and Other		(5,150)	(5,371)
Total Long-Term Debt		4,699,152	4,559,221
Less: Amounts Due Within One Year		66,286	66,286
Long-Term Debt		4,632,866	4,492,935
Total Capitalization		$ 8,561,699	$ 8,187,037

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

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 The Connecticut Light and Power Company and subsidiaries (CL&P or the Company) and of other sections of this annual report. CL&P 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, CL&P 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 Directors of The Connecticut Light and Power Company:

We have audited the accompanying consolidated balance sheets of The Connecticut Light and Power Company and subsidiaries (a Connecticut corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2010 and 2009, and the related statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 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 statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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 The Connecticut Light and Power Company 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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2010	2009
ASSETS		
Current Assets:		
Cash	$ 9,762	$ 45
Receivables, Net	317,530	327,969
Accounts Receivable from Affiliated Companies	822	2,362
Notes Receivable from Affiliated Companies	-	97,775
Unbilled Revenues	116,392	140,632
Taxes Receivable	48,360	147
Materials and Supplies	63,811	65,623
Derivative Assets	7,870	24,593
Accumulated Deferred Income Taxes	32,393	-
Prepayments and Other Current Assets	19,596	18,238
Total Current Assets	616,536	677,384
Property, Plant and Equipment, Net	5,586,504	5,340,561
Deferred Debits and Other Assets:		
Regulatory Assets	1,878,945	2,068,778
Derivative Assets	115,870	183,231
Other Long-Term Assets	89,730	94,610
Total Deferred Debits and Other Assets	2,084,545	2,346,619
Total Assets	$ 8,287,585	$ 8,364,564

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2010	2009
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 6,225	$ -
Long-Term Debt - Current Portion	62,000	62,000
Accounts Payable	204,868	242,853
Accounts Payable to Affiliated Companies	53,207	48,795
Obligations to Third Party Suppliers	68,692	39,609
Accrued Taxes	92,061	36,860
Accrued Interest	42,548	49,867
Derivative Liabilities	46,781	9,770
Other Current Liabilities	45,835	61,237
Total Current Liabilities	622,217	550,991
Rate Reduction Bonds	-	195,587
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,101,111	901,527
Regulatory Liabilities	282,110	316,160
Derivative Liabilities	883,091	913,349
Accrued Pension	42,486	51,319
Other Long-Term Liabilities	321,793	425,887
Total Deferred Credits and Other Liabilities	2,630,591	2,608,242
Capitalization:		
Long-Term Debt	2,521,102	2,520,361
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common Stock	60,352	60,352
Capital Surplus, Paid In	1,605,275	1,601,792
Retained Earnings	734,561	714,210
Accumulated Other Comprehensive Loss	(2,713)	(3,171)
Common Stockholder's Equity	2,397,475	2,373,183
Total Capitalization	5,034,777	5,009,744
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 8,287,585	$ 8,364,564

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2010	2009	2008
Operating Revenues	$ 2,999,102	$ 3,424,538	$ 3,558,361
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	1,253,329	1,690,671	1,845,367
Other Operating Expenses	524,328	571,024	557,565
Maintenance	96,522	117,822	130,365
Depreciation	172,167	186,922	162,636
Amortization of Regulatory Assets, Net	83,906	45,821	164,246
Amortization of Rate Reduction Bonds	167,021	155,938	145,590
Taxes Other Than Income Taxes	214,179	191,234	179,201
Total Operating Expenses	2,511,452	2,959,432	3,184,970
Operating Income	487,650	465,106	373,391
Interest Expense:			
Interest on Long-Term Debt	134,553	133,422	104,954
Interest on Rate Reduction Bonds	7,542	19,061	29,129
Other Interest (Note 11)	(4,357)	3,334	12,163
Interest Expense	137,738	155,817	146,246
Other Income, Net	26,669	25,874	41,865
Income Before Income Tax Expense	376,581	335,163	269,010
Income Tax Expense	132,438	118,847	77,852
Net Income	$ 244,143	$ 216,316	$ 191,158

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 244,143	$ 216,316	$ 191,158
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	444	445	(3,348)
Changes in Unrealized Gains/(Losses) on Other Securities	14	(30)	(59)
Other Comprehensive Income/(Loss), Net of Tax	458	415	(3,407)
Comprehensive Income	$ 244,601	$ 216,731	$ 187,751

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Share Information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance as of January 1, 2008	6,035,205	$ 60,352	$ 1,243,940	$ 538,138	$ (179)	$ 1,842,251
Net Income				191,158		191,158
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(106,461)		(106,461)
Allocation of Benefits ESOP			207			207
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			210,000			210,000
Other Comprehensive Loss					(3,407)	(3,407)
Balance as of December 31, 2008	6,035,205	60,352	1,454,198	617,276	(3,586)	2,128,240
Adoption of Accounting Guidance for Other-Than-Temporary Impairments (Note 1K)				25	(25)	-
Net Income				216,316		216,316
Dividends on Preferred Stock				(5,559)		(5,559)
Dividends on Common Stock				(113,848)		(113,848)
Allocation of Benefits - ESOP			(48)			(48)
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			147,591			147,591
Other Comprehensive Income					440	440
Balance as of December 31, 2009	6,035,205	60,352	1,601,792	714,210	(3,171)	2,373,183
Net Income				244,143		244,143
Dividends on Preferred Stock				(6,101)		(6,101)
Dividends on Common Stock				(217,691)		(217,691)
Allocation of Benefits - ESOP			919			919
Capital Stock Expenses, Net			51			51
Capital Contributions from NU Parent			2,513			2,513
Other Comprehensive Income					458	458
Balance as of December 31, 2010	6,035,205	$ 60,352	$ 1,605,275	$ 734,561	$ (2,713)	$ 2,397,475

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2010	2009	2008
Operating Activities:			
Net Income	$ 244,143	$ 216,316	$ 191,158
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	7,484	15,276	5,951
Depreciation	172,167	186,922	162,636
Deferred Income Taxes	115,069	52,900	47,653
Pension and PBOP Expense, Net of PBOP Contributions	1,595	(10,709)	(19,257)
Regulatory Overrecoveries/(Underrecoveries), Net	32,492	51,292	(153,843)
Amortization of Regulatory Assets, Net	83,906	45,821	164,246
Amortization of Rate Reduction Bonds	167,021	155,938	145,590
Other	(55,515)	(38,731)	(50,670)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	1,895	50,327	(125,241)
Investments in Securitizable Assets	-	-	(25,787)
Materials and Supplies	3,377	(6,339)	(15,204)
Taxes Receivable/Accrued	(56,002)	25,823	60,864
Accounts Payable	(35,976)	(85,773)	28,772
Other Current Assets and Liabilities	15,649	5,718	20,885
Net Cash Flows Provided by Operating Activities	697,305	664,781	437,753
Investing Activities:			
Investments in Property, Plant and Equipment	(380,304)	(435,723)	(849,549)
Decrease/(Increase) in NU Money Pool Lending	97,775	(97,775)	-
Other Investing Activities	5,385	4,888	(2,443)
Net Cash Flows Used in Investing Activities	(277,144)	(528,610)	(851,992)
Financing Activities:			
Cash Dividends on Common Stock	(217,691)	(113,848)	(106,461)
Cash Dividends on Preferred Stock	(5,559)	(5,559)	(5,559)
(Decrease)/Increase in Short-Term Debt	-	(187,973)	187,973
Issuance of Long-Term Debt	-	312,000	300,000
Increase/(Decrease) in NU Money Pool Borrowings	6,225	(102,725)	63,900
Retirements of Rate Reduction Bonds	(195,587)	(182,608)	(170,491)

Capital Contributions from NU Parent	2,513	147,591	210,000
Reacquisition of Long-Term Debt	-	-	(62,000)
Other Financing Activities	(345)	(3,004)	(3,661)
Net Cash Flows (Used in)/Provided by Financing Activities	(410,444)	(136,126)	413,701
Net Increase/(Decrease) in Cash	9,717	45	(538)
Cash - Beginning of Year	45	-	538
Cash - End of Year	$ 9,762	$ 45	$ -

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

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 Public Service Company of New Hampshire and subsidiaries (PSNH or the Company) and of other sections of this annual report. PSNH 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, PSNH 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 Directors of Public Service Company of New Hampshire:

We have audited the accompanying consolidated balance sheets of Public Service Company of New Hampshire and subsidiaries (a New Hampshire corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2010 and 2009, and the related statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 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 statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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 Public Service Company of New Hampshire 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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	As of December 31, 2010	2009
ASSETS		
Current Assets:		
Cash	$ 2,559	$ 1,974
Receivables, Net	105,070	89,337
Accounts Receivable from Affiliated Companies	858	286
Unbilled Revenues	48,691	49,358
Taxes Receivable	12,564	22,600
Fuel, Materials and Supplies	116,074	127,447
Prepayments and Other Current Assets	30,817	36,387
Total Current Assets	316,633	327,389
Property, Plant and Equipment, Net	2,053,281	1,814,714
Deferred Debits and Other Assets:		
Regulatory Assets	434,418	494,077
Other Long-Term Assets	85,508	61,011
Total Deferred Debits and Other Assets	519,926	555,088
Total Assets	$ 2,889,840	$ 2,697,191

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
(Thousands of Dollars)	2010	2009
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 30,000	$ -
Notes Payable to Affiliated Companies	47,900	26,700
Accounts Payable	85,324	109,521
Accounts Payable to Affiliated Companies	20,007	20,083
Accrued Interest	10,231	10,255
Derivative Liabilities	12,834	18,785
Other Current Liabilities	35,144	27,983
Total Current Liabilities	241,440	213,327
Rate Reduction Bonds	138,247	188,113
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	327,297	275,669
Regulatory Liabilities	66,996	69,872
Derivative Liabilities	-	7,635
Accrued Pension	261,096	272,905
Other Long-Term Liabilities	91,952	105,970
Total Deferred Credits and Other Liabilities	747,341	732,051
Capitalization:		
Long-Term Debt	836,365	836,255
Common Stockholder's Equity:		
Common Stock	-	-
Capital Surplus, Paid In	579,577	420,169
Retained Earnings	347,471	307,988
Accumulated Other Comprehensive Loss	(601)	(712)
Common Stockholder's Equity	926,447	727,445
Total Capitalization	1,762,812	1,563,700
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 2,889,840	$ 2,697,191

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars)	For the Years Ended December 31, 2010	2009	2008
Operating Revenues	$ 1,033,439	$ 1,109,591	$ 1,141,202
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	363,147	520,529	558,313
Other Operating Expenses	230,210	239,650	215,497
Maintenance	82,384	87,026	90,933
Depreciation	67,237	61,961	56,321
Amortization of Regulatory Assets/(Liabilities), Net	11,232	(29,619)	9,254
Amortization of Rate Reduction Bonds	50,357	47,482	45,644
Taxes Other Than Income Taxes	52,686	47,975	42,291
Total Operating Expenses	857,253	975,004	1,018,253
Operating Income	176,186	134,587	122,949
Interest Expense:			
Interest on Long-Term Debt	36,220	33,045	32,655
Interest on Rate Reduction Bonds	9,660	13,128	15,969
Other Interest	1,187	316	1,539
Interest Expense	47,067	46,489	50,163
Other Income, Net	11,749	9,462	7,277
Income Before Income Tax Expense	140,868	97,560	80,063
Income Tax Expense	50,801	31,990	21,996
Net Income	$ 90,067	$ 65,570	$ 58,067

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	2010	2009	2008
Net Income	$ 90,067	$ 65,570	$ 58,067
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified Cash Flow Hedging Instruments	87	87	(1,418)
Changes in Unrealized Gains/(Losses) on Other Securities	24	(50)	(101)
Other Comprehensive Income/(Loss), Net of Tax	111	37	(1,519)
Comprehensive Income	$ 90,178	$ 65,607	$ 56,548

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Share Information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance as of January 1, 2008	301	$ -	$ 275,569	$ 261,528	$ 770	$ 537,867
Net Income				58,067		58,067
Dividends on Common Stock				(36,376)		(36,376)
Allocation of Benefits - ESOP			93			93
Capital Contributions from NU Parent			75,583			75,583
Other Comprehensive Loss					(1,519)	(1,519)
Balance as of December 31, 2008	301	-	351,245	283,219	(749)	633,715
Adoption of Accounting Guidance for Other-Than-Temporary Impairments (Note 1K)				43	(43)	-
Net Income				65,570		65,570
Dividends on Common Stock				(40,844)		(40,844)
Allocation of Benefits - ESOP			(22)			(22)
Capital Contributions from NU Parent			68,946			68,946
Other Comprehensive Income					80	80
Balance as of December 31, 2009	301	-	420,169	307,988	(712)	727,445
Net Income				90,067		90,067
Dividends on Common Stock				(50,584)		(50,584)
Allocation of Benefits - ESOP			439			439
Capital Contributions from NU Parent			158,969			158,969
Other Comprehensive Income					111	111
Balance as of December 31, 2010	301	$ -	$ 579,577	$ 347,471	$ (601)	$ 926,447

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS
OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2010	2009	2008
Operating Activities:			
Net Income	$ 90,067	$ 65,570	$ 58,067
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	8,858	10,084	5,661
Depreciation	67,237	61,961	56,321
Deferred Income Taxes	39,225	35,270	25,001
Pension and PBOP Expense, Net of PBOP Contributions	20,423	15,519	12,350
Pension Contribution	(45,000)	-	-
Regulatory Underrecoveries, Net	(2,834)	(4,392)	(23,848)
Amortization of Regulatory Assets/(Liabilities), Net	11,232	(29,619)	9,254
Amortization of Rate Reduction Bonds	50,357	47,482	45,644
Insurance Proceeds	10,000	10,066	-
Other	(41,590)	(7,526)	(33,897)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(24,497)	1,505	(12,058)
Fuel, Materials and Supplies	14,891	59	(26,209)
Taxes Receivable/Accrued	10,037	(13,791)	(2,117)
Accounts Payable	(14,427)	(77,738)	41,959
Other Current Assets and Liabilities	1,294	(9,192)	7,148
Net Cash Flows Provided by Operating Activities	195,273	105,258	163,276
Investing Activities:			
Investments in Property, Plant and Equipment	(296,335)	(266,440)	(238,912)
Decrease/(Increase) in NU Money Pool Lending	-	53,800	(53,800)
Other Investing Activities	(7,819)	(1,278)	4,607
Net Cash Flows Used in Investing Activities	(304,154)	(213,918)	(288,105)

Financing Activities:			
Cash Dividends on Common Stock	(50,584)	(40,844)	(36,376)
Increase/(Decrease) in Short-Term Debt	30,000	(45,227)	35,227
Issuance of Long-Term Debt	-	150,000	110,000
Increase/(Decrease) in NU Money Pool Borrowings	21,200	26,700	(11,300)
Retirements of Rate Reduction Bonds	(49,867)	(47,026)	(46,879)
Capital Contributions from NU Parent	158,969	68,946	75,583
Other Financing Activities	(252)	(2,110)	(1,681)
Net Cash Flows Provided by Financing Activities	109,466	110,439	124,574
Net Increase/(Decrease) in Cash	585	1,779	(255)
Cash - Beginning of Year	1,974	195	450
Cash - End of Year	$ 2,559	$ 1,974	$ 195

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

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 Western Massachusetts Electric Company and subsidiary (WMECO or the Company) and of other sections of this annual report. WMECO 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, WMECO 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 December 31, 2010.

February 25, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Western Massachusetts Electric Company:

We have audited the accompanying consolidated balance sheets of Western Massachusetts Electric Company and subsidiary (a Massachusetts corporation and a wholly owned subsidiary of Northeast Utilities) (the "Company") as of December 31, 2010 and 2009, and the related statements of income, comprehensive income, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 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 statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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 Western Massachusetts Electric Company and subsidiary 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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Thousand of Dollars)	At December 31, 2010	2009
ASSETS		
Current Assets:		
Cash	$ 1	$ 1
Receivables, Net	37,585	38,415
Accounts Receivable from Affiliated Companies	505	191
Unbilled Revenues	16,578	16,090
Taxes Receivable	7,346	4,192
Materials and Supplies	3,664	8,314
Marketable Securities	33,194	28,261
Prepayments and Other Current Assets	1,968	1,774
Total Current Assets	100,841	97,238
Property, Plant and Equipment, Net	817,146	705,760
Deferred Debits and Other Assets:		
Regulatory Assets	227,115	240,804
Marketable Securities	23,860	28,500
Other Long-Term Assets	30,597	29,498
Total Deferred Debits and Other Assets	281,572	298,802
Total Assets	$ 1,199,559	$ 1,101,800

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	December 31,	
(Thousands of Dollars)	2010	2009
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ 20,400	$ 136,100
Accounts Payable	48,344	36,680
Accounts Payable to Affiliated Companies	7,848	7,924
Accrued Interest	6,787	5,274
Other Current Liabilities	11,474	8,873
Total Current Liabilities	94,853	194,851
Rate Reduction Bonds	43,325	58,735
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	222,333	211,391
Regulatory Liabilities	23,008	21,683
Other Long-Term Liabilities	58,168	62,858
Total Deferred Credits and Other Liabilities	303,509	295,932
Capitalization:		
Long-Term Debt	400,288	305,475
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	248,044	145,400
Retained Earnings	98,757	90,549
Accumulated Other Comprehensive Loss	(83)	(8)
Common Stockholder's Equity	357,584	246,807
Total Capitalization	757,872	552,282
Commitments and Contingencies (Note 12)		
Total Liabilities and Capitalization	$ 1,199,559	$ 1,101,800

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2010	2009	2008
Operating Revenues	$ 395,161	$ 402,413	$ 441,527
Operating Expenses:			
Fuel, Purchased and Net Interchange Power	157,276	192,177	237,369
Other Operating Expenses	102,053	85,591	76,929
Maintenance	19,196	17,895	20,720
Depreciation	23,561	22,454	21,025
Amortization of Regulatory Assets/(Liabilities), Net	2,395	(2,980)	12,445
Amortization of Rate Reduction Bonds	15,494	14,521	13,625
Taxes Other Than Income Taxes	16,529	14,174	12,867
Total Operating Expenses	336,504	343,832	394,980
Operating Income	58,657	58,581	46,547
Interest Expense:			
Interest on Long-Term Debt	17,988	14,074	13,244
Interest on Rate Reduction Bonds	3,372	4,335	5,133
Other Interest	479	877	1,256
Interest Expense	21,839	19,286	19,633
Other Income, Net	2,597	1,824	1,961
Income Before Income Tax Expense	39,415	41,119	28,875
Income Tax Expense	16,325	14,923	10,545
Net Income	$ 23,090	$ 26,196	$ 18,330

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income	$ 23,090	$ 26,196	$ 18,330
Other Comprehensive Loss, Net of Tax:			
Qualified Cash Flow Hedging Instruments	(79)	(79)	(79)
Changes in Unrealized Gains/(Losses) on Other Securities	4	(119)	38
Other Comprehensive Loss, Net of Tax	(75)	(198)	(41)
Comprehensive Income	$ 23,015	$ 25,998	$ 18,289

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

(Thousands of Dollars, Except Share Information)	Common Stock Shares	Common Stock Amount	Capital Surplus, Paid In	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total
Balance as of January 1, 2008	434,653	$ 10,866	$ 128,228	$ 103,925	$ 231	$ 243,250
Net Income				18,330		18,330
Dividends on Common Stock				(39,706)		(39,706)
Allocation of Benefits - ESOP			36			36
Capital Contributions from NU Parent			16,281			16,281
Other Comprehensive Loss					(41)	(41)
Balance as of December 31, 2008	434,653	10,866	144,545	82,549	190	238,150
Adoption of Accounting Guidance for Other-Than-Temporary Impairments (Note 1K)				7	(7)	-
Net Income				26,196		26,196
Dividends on Common Stock				(18,203)		(18,203)
Allocation of Benefits - ESOP			(8)			(8)
Capital Contributions from NU Parent			863			863
Other Comprehensive Loss					(191)	(191)
Balance as of December 31, 2009	434,653	10,866	145,400	90,549	(8)	246,807
Net Income				23,090		23,090
Dividends on Common Stock				(14,882)		(14,882)
Allocation of Benefits - ESOP			165			165
Capital Contributions from NU Parent			102,479			102,479
Other Comprehensive Loss					(75)	(75)
Balance as of December 31, 2010	434,653	$ 10,866	$ 248,044	$ 98,757	$ (83)	$ 357,584

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2010	2009	2008
Operating Activities:			
Net Income	$ 23,090	$ 26,196	$ 18,330
Adjustments to Reconcile Net Income to Net Cash Flows			
Provided by Operating Activities:			
Bad Debt Expense	9,747	7,590	8,185
Depreciation	23,561	22,454	21,025
Deferred Income Taxes	10,963	22,908	12,222
Pension Income and PBOP Expense, Net of PBOP Contributions	(535)	(2,630)	(4,844)
Regulatory (Underrecoveries)/Overrecoveries, Net	(11,551)	589	(17,093)
Amortization of Regulatory Assets/(Liabilities), Net	2,395	(2,980)	12,445
Amortization of Rate Reduction Bonds	15,494	14,521	13,625
Other	(7,032)	(5,547)	(9,697)
Changes in Current Assets and Liabilities:			
Receivables and Unbilled Revenues, Net	(6,838)	3,757	(14,210)
Materials and Supplies	4,650	(4,489)	(1,490)
Taxes Receivable/Accrued	(393)	1,307	4,081
Accounts Payable	(92)	(19,397)	22,186
Other Current Assets and Liabilities	2,406	(2,150)	2,718
Net Cash Flows Provided by Operating Activities	65,865	62,129	67,483
Investing Activities:			
Investments in Property, Plant and Equipment	(115,178)	(105,440)	(78,253)
Proceeds from Sales of Marketable Securities	114,191	106,308	169,056
Purchases of Marketable Securities	(114,587)	(106,937)	(169,902)
Other Investing Activities	(888)	1,298	939
Net Cash Flows Used in Investing Activities	(116,462)	(104,771)	(78,160)
Financing Activities:			
Cash Dividends on Common Stock	(14,882)	(18,203)	(39,706)

(Decrease)/Increase in Short-Term Debt	-	(29,850)	29,850
Issuance of Long-Term Debt	95,000	-	-
(Decrease)/Increase in NU Money Pool Borrowings	(115,700)	104,500	16,700
Retirements of Rate Reduction Bonds	(15,410)	(14,441)	(13,555)
Capital Contributions from NU Parent	102,479	863	16,281
Other Financing Activities	(890)	(226)	(3)
Net Cash Flows Provided by Financing Activities	50,597	42,643	9,567
Net Increase/(Decrease) in Cash	-	1	(1,110)
Cash - Beginning of Year	1	-	1,110
Cash - End of Year	$ 1	$ 1	$ -

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A.

Proposed Merger with NSTAR

On October 18, 2010, Northeast Utilities (NU or the Company) 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.

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 NU would issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Subject to the conditions in the agreement, NU s first quarterly dividend per 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.

In accordance with accounting standards for business combinations, NU will account for the transaction as an acquisition of NSTAR by NU and, upon completion of the transaction, NSTAR will become a direct wholly owned subsidiary of NU.

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, the continued effectiveness of the registration statement for the NU shares to be issued to NSTAR shareholders in the merger, and receipt of all required regulatory approvals. Special meetings of shareholders of both companies to approve the merger are scheduled for March 4, 2011.

B.

Presentation

The consolidated financial statements of NU, CL&P, PSNH and WMECO include the accounts of all their respective subsidiaries. Intercompany transactions have been eliminated in consolidation.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

In accordance with accounting guidance on the consolidation of VIEs, the Company evaluates its variable interests to determine if it has a controlling financial interest in a VIE that would require consolidation. The Company's variable interests outside of the consolidated group consist of contracts with developers of power plants that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. The Company would consolidate a VIE if it had both the power to direct the activities of a VIE that most significantly impact the entity's economic performance and the obligation to absorb losses of, or receive benefits from, the entity that could potentially be significant to the VIE.

For each variable interest in a power plant, NU evaluates the activities of that particular power plant that most significantly impact the VIE's economic performance to determine whether it has control over those activities. NU's assessment of control includes an analysis of who operates and maintains the power plant including dispatch rights and who controls the activities of the power plant after the expiration of its power purchase agreement with NU. NU also evaluates its exposure to potentially significant losses and benefits of the VIE. As of December 31, 2010, NU held variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants and with other independent power producers. NU does not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. NU does not have financial exposure because the costs and benefits of all of these arrangements are fully recoverable from, or refundable to, NU's customers. As of December 31, 2010, NU was not identified as the primary beneficiary of, and therefore does not consolidate, any power plant VIEs.

NUTV and a subsidiary of NSTAR have formed a 75 percent/25 percent owned limited liability company, NPT, to construct, own and operate the Northern Pass transmission project. NPT and Hydro Renewable Energy entered into a TSA whereby NPT will sell to Hydro Renewable Energy electric transmission rights over the Northern Pass for a

40-year term at cost of service rates. NPT will be required to maintain a 50/50 debt to equity ratio. NU determined that NUTV, through its controlling financial interest in NPT, must consolidate NPT, as NUTV has the power to direct the activities of NPT which most significantly impact its economic performance, including permitting and siting and operation and maintenance activities over the term of the TSA. As of December 31, 2010, NPT had property, plant and equipment of $9.7 million and current liabilities of $3.9 million. NPT s assets are restricted to use by NPT and its creditors do not have recourse to NU.

The Company does not have any variable interests in an unconsolidated VIE that are material to the accompanying consolidated financial statements.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements effective January 1, 2009, the Preferred Stock of CL&P, which is not owned by NU or its consolidated subsidiaries and is not subject to mandatory redemption, has been presented as a noncontrolling interest in CL&P in the accompanying consolidated financial statements of NU. The Preferred Stock of CL&P is considered to be temporary equity and has been classified between liabilities and permanent shareholders' equity on the accompanying consolidated balance sheets of NU and CL&P due to a provision in CL&P's certificate of incorporation that grants preferred stockholders the right to elect a majority of CL&P's board of directors should certain conditions exist, such as if preferred dividends are in arrears for one year. The Net Income reported in the accompanying consolidated statements of income and cash flows represents consolidated net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR's portion of the net income of NPT.

The included presentation and disclosure requirements effective January 1, 2009 have been applied retrospectively to the consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for the year ended December 31, 2008. For the years ended December 31, 2010, 2009 and 2008, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

Certain other reclassifications of prior period data were made in the accompanying consolidated balance sheets and statements of cash flows for all companies presented. These reclassifications were made to conform to the current year's presentation.

NU evaluates events and transactions that occur after the balance sheet date but before financial statements are issued and recognizes in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed as of the balance sheet date and discloses but does not recognize in the financial statements subsequent events that provide evidence about the conditions that arose after the balance sheet date but before the financial statements are issued. See Note 22, "Subsequent Event," for further information.

C.

About NU, CL&P, PSNH and WMECO

Consolidated: NU is the parent company of CL&P, PSNH, WMECO, Yankee Gas and NU Enterprises, as described below. NU was formed on July 1, 1966 when CL&P, WMECO and The Hartford Electric Light Company affiliated under the common ownership of NU. In 1992, PSNH became a subsidiary of NU. On March 1, 2000, natural gas became an integral part of NU's Connecticut operations when NU's merger with Yankee and its principal subsidiary, Yankee Gas, was completed. CL&P, PSNH and WMECO are reporting companies under the Securities Exchange Act of 1934. NU is a public utility holding company under the Public Utility Holding Company Act of 2005. Arrangements among the regulated electric companies, NU Enterprises and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. The Regulated companies are subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the DPUC for CL&P and Yankee Gas, the NHPUC as well as certain regulatory oversight by the Vermont Department of Public Service and the Maine Public Utilities Commission for PSNH, and the DPU for WMECO).

Regulated Companies: CL&P, PSNH and WMECO furnish franchised retail electric service in Connecticut, New Hampshire and Massachusetts, respectively. Yankee Gas owns and operates Connecticut's largest natural gas distribution system. CL&P, PSNH and WMECO's results include the operations of their respective distribution and transmission segments. PSNH's and WMECO's distribution results include the operations of their respective generation businesses. Yankee Gas' results include the operations of its natural gas distribution segment. NPT was formed to construct, own and operate the Northern Pass line, a new HVDC transmission line from Québec to New Hampshire that will interconnect with a new HVDC transmission line being developed by a transmission subsidiary of HQ.

NU Enterprises: NU Enterprises is the parent company of Select Energy, Boulos, NGS, NGS Mechanical and SECI. As of December 31, 2010, NU Enterprises   primary business consisted of (i) Select Energy   s remaining energy wholesale marketing contracts, and (ii) NGS   operation and maintenance agreements as well as its subsidiary, Boulos, an electrical contractor based in Maine that NU Enterprises continues to own and manage.

D.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, any overdraft amounts are reclassified from Cash and Cash Equivalents to Accounts Payable on the accompanying consolidated balance sheets.

E.

Restricted Cash

As of December 31, 2009, PSNH had $10 million of restricted cash held with a trustee related to insurance proceeds received on bondable property, which was included in Prepayments and Other Current Assets on the accompanying consolidated balance sheet. These funds were released from the trustee during the second quarter of 2010 and there was no restricted cash held as of December 31, 2010.

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F.

Provision for Uncollectible Accounts

NU, including CL&P, PSNH and WMECO, maintains a provision for uncollectible accounts to record receivables at an estimated net realizable value. This provision is determined based upon a variety of factors, including applying an estimated uncollectible account percentage to each receivable aging category, based upon historical collection and write-off experience and management's assessment of collectibility from individual customers. Management reviews at least quarterly the collectibility of the receivables, and if circumstances change, collectibility estimates are adjusted accordingly. Receivable balances are written-off against the provision for uncollectible accounts when the accounts are terminated and these balances are deemed to be uncollectible.

The provision for uncollectible accounts, which is included in Receivables, Net on the accompanying consolidated balance sheets, was as follows:

	As of December 31,	
(Millions of Dollars)	**2010**	**2009**
NU	$ 39.8	$ 55.3
CL&P	17.2	26.1
PSNH	6.8	5.1
WMECO	6.0	7.2

The DPUC allows CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. As of December 31, 2010, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $65 million and $7.5 million, respectively, with the corresponding bad debt expense recorded as Regulatory Assets as these amounts are probable of recovery. As of December 31, 2009, these amounts totaled $54.5 million and $8.6 million, respectively.

As of December 31, 2010 and 2009, WMECO had a reserve for uncollectible hardship accounts receivable of $6.9 million and $9.1 million, respectively. As a result of the January 2011 DPU decision, WMECO is allowed to collect these amounts in rates.

G.

Fuel, Materials and Supplies and Allowance Inventory

Fuel, Materials and Supplies include natural gas, coal, oil and materials purchased primarily for construction or operation and maintenance purposes. Natural gas inventory, coal and oil are valued at their respective weighted average cost. Materials and supplies are valued at the lower of average cost or market.

PSNH is subject to federal and state laws and regulations that regulate emissions of air pollutants, including SO_2, CO_2, and NO_x related to its regulated generation units, and uses SO_2, CO_2, and NO_x emissions allowances. At the end of each compliance period, PSNH is required to relinquish SO_2, CO_2, and NO_x emissions allowances corresponding to the actual emissions emitted by its generating units over the compliance period. SO_2 and NO_x emissions allowances are obtained through an annual allocation from the federal and state regulators that are granted at no cost and through purchases from third parties. CO_2 emissions allowances are acquired through auctions and through purchases from third parties.

SO_2, CO_2, and NO_x emissions allowances are recorded within Fuel, Materials and Supplies and are classified on the balance sheet as short-term or long-term depending on the period they are expected to be utilized against actual emissions. As of December 31, 2010 and 2009, PSNH had $7.1 million and $7.8 million, respectively, of short-term SO_2, CO_2, and NO_x emissions allowances classified as Fuel, Materials and Supplies on the accompanying consolidated balance sheets and $18.2 million and $20.7 million, respectively, of long-term SO_2 and CO_2 emissions allowances classified as Other Long-Term Assets on the accompanying consolidated balance sheets.

SO_2, CO_2, and NO_x emissions allowances are charged to expense based on their weighted average cost as they are utilized against emissions volumes at PSNH's generating units. PSNH recorded expenses of $6.6 million, $7.6 million and $2.8 million for the years ended December 31, 2010, 2009, and 2008, respectively, which was included in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income. These costs are recovered from customers through PSNH ES revenues. See Note 2, "Regulatory Accounting," for further information.

H.

Special Deposits and Counterparty Deposits

To the extent NU Enterprises, through Select Energy, requires collateral from counterparties, or the counterparties require collateral from Select Energy, cash is held on deposit by Select Energy or with unaffiliated counterparties and brokerage firms as a part of the total collateral required based on Select Energy's position in transactions with the counterparty. Select Energy's right to use cash collateral is determined by the terms of the related agreements. Key factors affecting the unrestricted status of a portion of this cash collateral include the financial standing of Select Energy and of NU as its credit supporter.

Special deposits paid by Select Energy to unaffiliated counterparties and brokerage firms not subject to master netting agreements totaled $22.6 million and $28.1 million as of December 31, 2010 and 2009, respectively. These amounts are included in Prepayments and Other Current Assets on the accompanying consolidated balance sheets. There were no counterparty deposits for Select Energy as of December 31, 2010 and 2009.

NU, including CL&P, PSNH, and WMECO, records special deposits and counterparty deposits posted under master netting agreements as an offset to a derivative asset or liability if the related derivatives are recorded in a net position. For further information, see Note 4, "Derivative Instruments" to the consolidated financial statements.

NU, CL&P, PSNH and WMECO have established credit policies regarding counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties, financial condition, collateral requirements and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. These evaluations result in established credit limits prior to entering into a contract. As of December 31, 2010 and 2009, there were no counterparty deposits for these companies.

CL&P, PSNH and WMECO had amounts on deposit related to subsidiaries used to facilitate the issuance of RRBs. In addition, CL&P, PSNH and WMECO had other cash deposits held with unaffiliated parties as of December 31, 2010 and 2009. These amounts were as follows:

	As of December 31,	
	2010	**2009**
(Millions of Dollars)	**NU**	**NU**
Rate Reduction Bond Deposits	$ 53.1	$ 40.2
Other Deposits	7.3	8.1

	As of December 31,					
	2010			**2009**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Rate Reduction Bond Deposits	$ 22.1	$ 26.9	$ 4.1	$ 16.8	$ 19.7	$ 3.7
Other Deposits	2.1	2.8	1.2	5.0	2.2	-

These amounts are included in Other Long-Term Assets on the accompanying consolidated balance sheets.

I.

Fair Value Measurements

NU, including CL&P, PSNH, and WMECO, applies fair value measurement guidance to all derivative contracts recorded at fair value and to the marketable securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. Fair value measurement guidance is also applied to investment valuations used to calculate the funded status of NU's Pension and PBOP plans and non-recurring fair value measurements of NU's non-financial assets and liabilities, such as AROs and Yankee Gas' goodwill.

Upon adoption of fair value measurement guidance, the Company recorded a pre-tax charge to Net Income of $6.1 million as of January 1, 2008 related to derivative liabilities for its remaining unregulated wholesale marketing contracts. In 2010, 2009 and 2008, the Company recorded benefits of $0.8 million, $0.7 million and $0.8 million, respectively, to partially reverse the exit price impact recorded as the Company served out rather than exited its one remaining fixed price forward sales contract. In 2008, the Company also recorded a benefit of $1.8 million related to a contract that expired in May 2008.

Fair Value Hierarchy: In measuring fair value, NU uses observable market data when available and minimizes the use of unobservable inputs. Unobservable inputs are needed to value certain derivative contracts due to complexities in the terms of the contracts. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. NU evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and NU's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products. Significant unobservable inputs are used in the valuations, including items such as energy and energy-related product prices in future years for which observable prices are not yet available, future contract quantities under full-requirements or supplemental sales contracts, and market volatilities. Items valued using these valuation techniques are classified according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, an item may be classified in Level 3 even though there may be some significant inputs that are readily observable.

Determination of Fair Value: The valuation techniques and inputs used in NU's fair value measurements are described in Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the consolidated financial statements. There were no changes to the valuation methodologies for derivative instruments or marketable securities as of December 31, 2010 and 2009.

J.

Derivative Accounting

Most of CL&P and PSNH's contracts for the purchase and sale of energy or energy related products are derivatives, along with all but one of NU Enterprises' remaining wholesale marketing contracts. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the "normal purchases or normal sales" (normal) exception, identifying, electing and designating hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on the consolidated financial statements.

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the Company determines whether it is a derivative by using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts. The fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability to the consolidated balance sheets.

The judgment applied in the election of the normal exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery of the underlying product and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. The Company has elected normal on many derivative contracts, including all of WMECO's derivative contracts. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied prospectively.

All but one of the contracts that comprise NU Enterprises' wholesale marketing activities are derivatives, and many of NU's regulated company contracts for the purchase or sale of energy or energy-related products are derivatives. Wholesale marketing contracts, which are marked-to-market derivative contracts, are not considered to be held for trading purposes, and sales and purchase activity is reported on a net basis in Fuel, Purchased and Net Interchange Power on the consolidated statements of income.

For further information regarding derivative contracts of NU, CL&P, PSNH and WMECO and their accounting, see Note 4, "Derivative Instruments," to the consolidated financial statements.

K.

Marketable Securities

NU Supplemental Benefit Trust and WMECO Spent Nuclear Fuel Trust: NU maintains a supplemental benefit trust to fund NU's SERP and non-SERP obligations and WMECO maintains a spent nuclear fuel trust to fund WMECO's prior period spent nuclear fuel liability, both of which hold marketable securities.

Other-than-temporary impairments on debt securities held in the NU supplemental benefit trust that NU intends to sell or will be required to sell are recorded in Net Income. Credit losses identified on debt securities held in the NU supplemental benefit trust are also recorded in Net Income. Unrealized gains and unrealized losses on debt securities held in the NU supplemental benefit trust that NU does not intend to sell or will not be required to sell are recorded in Accumulated Other Comprehensive Income/(Loss). Realized gains and losses on debt securities WMECO intends to sell or will be required to sell, credit losses and unrealized gains and losses associated with the WMECO spent nuclear fuel trust are recorded on the accompanying consolidated balance sheets due to the regulatory accounting treatment of this trust.

In the second quarter of 2009, NU adopted new accounting guidance related to the recognition and presentation of other- than-temporary impairments. NU recorded an after-tax cumulative effect of accounting change in accounting principle of $0.7 million as an increase to Retained Earnings with an offset to Accumulated Other Comprehensive Income relating to unrealized losses previously recorded in Net Income on debt securities held in the NU supplemental benefit trust, which did not meet the criteria established in the new accounting guidance.

Prior to the adoption of accounting guidance in the second quarter of 2009, changes in the fair value of debt securities in the NU supplemental benefit trust and the WMECO spent nuclear fuel trust relating to unrealized losses were considered other-than-temporary because NU and WMECO did not have the ability to hold the debt securities to maturity. Losses on the NU supplemental benefit trust were recorded in Net Income and losses on the WMECO spent nuclear fuel trust were recorded on the balance sheet due to the regulatory nature of the trust.

In 2010 and 2009, under applicable fair value accounting guidance, the Company elected to record changes in fair value of newly purchased equity securities in the NU supplemental benefit trust in Net Income. Realized and unrealized gains and losses related to these securities are included in Other Income, Net, on the accompanying consolidated statements of income for the years ended December 31, 2010 and 2009.

These trusts are not subject to regulatory oversight by state or federal agencies.

For information regarding marketable securities, see Note 5, "Marketable Securities," to the consolidated financial statements.

L.

Equity Method Investments

Regional Nuclear Companies: As of December 31, 2010, CL&P, PSNH and WMECO owned common stock in three regional nuclear generation companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating facility that has been decommissioned. Ownership interests in the Yankee Companies as of December 31, 2010, which are accounted for on the equity method, are as follows:

(Percent)	**CYAPC**	**YAEC**	**MYAPC**
CL&P	34.5	24.5	12.0
PSNH	5.0	7.0	5.0
WMECO	9.5	7.0	3.0
Total NU	49.0 %	38.5 %	20.0 %

The total carrying values of ownership interests in CYAPC, YAEC and MYAPC, which are included in Other Long-Term Assets on the accompanying consolidated balance sheets and in the Regulated companies - Electric distribution reportable segment, are as follows:

(Millions of Dollars)		**2010**		**2009**
CL&P	$	1.3	$	1.6
PSNH		0.3		0.4
WMECO		0.4		0.5
Total NU	$	2.0	$	2.5

Regional Transmission Companies: NU parent has a 22.7 percent equity ownership interest in two companies that transmit electricity imported from the Hydro-Québec system in Canada. NU parent's investment, which is included in Other-Long Term Assets on the accompanying consolidated balance sheets, totaled $5.6 million and $6.2 million as of December 31, 2010 and 2009, respectively.

Dividends received from the Yankee Companies and the regional transmission companies investments were recorded as a reduction to NU's, including CL&P, PSNH and WMECO, investment and were as follows:

	For the Years Ended December 31,					
(Millions of Dollars)		**2010**		**2009**		**2008**
NU	$	1.5	$	3.8	$	1.0

CL&P	0.4	1.5	-
PSNH	0.1	0.2	-
WMECO	0.1	0.4	-

Net earnings related to these equity investments are included in Other Income, Net on the accompanying consolidated statements of income. For further information, see Note 1P, "Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

The application of the equity method is considered the appropriate method to account for the Yankee Companies and the regional transmission companies investments because NU's ownership interests are between 20 and 50 percent of the voting stock and NU has the ability to exercise significant influence over the investees' operating and financial policies.

For further information on the Yankee Companies, see Note 12D, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

M.

Revenues

Regulated Companies: The Regulated companies' retail revenues are based on rates approved by the state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. The Regulated companies also utilize regulatory commission-approved tracking mechanisms to recover certain costs as incurred. The tracking mechanisms allow for rates to be changed periodically, with overcollections refunded to customers or undercollections collected from customers in future periods.

The Regulated companies record monthly, day ahead and real time energy purchases and sales net in accordance with applicable accounting guidance. Revenues and expenses associated with derivative instruments to purchase and sell energy in the day ahead and real time markets are recorded on a net basis in Operating Revenues or Fuel, Purchased and Net Interchange Power on the consolidated statements of income.

Regulated Companies' Unbilled Revenues: Unbilled revenues represent an estimate of electricity or natural gas delivered to customers for which the customers have not yet been billed. Unbilled revenues are included in Operating Revenues on the consolidated statements of income and are assets on the consolidated balance sheets 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.

The Regulated companies estimate unbilled revenues monthly using the daily load cycle method. The daily load cycle method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total calendar month sales to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective rate classes, then applying an average rate to the estimate of unbilled sales.

Regulated Companies' Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Wholesale transmission revenues for CL&P, PSNH, and WMECO are collected under the ISO-NE FERC, Transmission, Markets and Services Tariff (ISO-NE Tariff). The ISO-NE Tariff includes Regional Network Service (RNS) and Schedule 21 - NU rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, including CL&P, PSNH, and WMECO's transmission businesses, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The Schedule 21 - NU rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 100 percent of the CWIP that is included in rate base on the NEEWS projects. The Schedule 21 - NU rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all of CL&P's, PSNH's and WMECO's regional and local revenue requirements as prescribed in the ISO-NE Tariff. Both the RNS and Schedule 21 - NU rates provide for the annual reconciliation and recovery/refund of estimated (or projected) costs to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from, or refunded to, customers. As of December 31, 2010, the Schedule 21 - NU rates were 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.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. CL&P, PSNH and WMECO each have a retail transmission cost tracking mechanism as part of their rates, which allows the companies to charge their retail customers for transmission costs on a timely basis.

NU Enterprises: Service revenues are recognized as services are provided, often on a percentage of completion basis. Wholesale marketing revenues are recognized through mark-to-market accounting on underlying derivative contracts and recorded in Fuel, Purchased and Net Interchange Power on the consolidated statements of income. This net presentation of the mark-to-market and settlement amounts is required as a result of NU Enterprises not being able to assert that physical delivery of contract quantities is probable.

N.

Operating Expenses

Fuel, Purchased and Net Interchange Power: For the years ended December 31, 2010, 2009 and 2008, Fuel, Purchased and Net Interchange Power included costs related to fuel (and natural gas costs as it related to Yankee Gas) as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2010**	**2009**	**2008**
CL&P	$ 0.3	$ 0.5	$ 4.1
PSNH	184.3	174.1	177.4
WMECO	0.1	0.8	0.8
Yankee Gas	206.4	226.1	358.8
Other	0.5	0.2	0.6
NU	$ 391.6	$ 401.7	$ 541.7

O.

Allowance for Funds Used During Construction

AFUDC is included in the cost of the Regulated companies' utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Other Interest Expense and the AFUDC related to equity funds is recorded as Other Income, Net on the accompanying consolidated statements of income.

	For the Years Ended December 31, NU		
(Millions of Dollars, except percentages)	**2010**	**2009**	**2008**
AFUDC:			
Borrowed Funds	$ 10.2	$ 5.9	$ 17.8
Equity Funds	16.7	9.4	29.0
Total	$ 26.9	$ 15.3	$ 46.8
Average AFUDC Rates	7.1%	6.1%	8.1 %

	For the Years Ended December 31,								
	2010			**2009**			**2008**		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
AFUDC:									
Borrowed Funds	$ 2.7	$ 6.6	$ 0.3	$ 2.2	$ 3.1	$ 0.2	$ 13.0	$ 3.0	$ 1.0
Equity Funds	4.9	10.4	0.6	5.7	3.6	-	23.2	4.4	1.2
Total	$ 7.6	$ 17.0	$ 0.9	$ 7.9	$ 6.7	$ 0.2	$ 36.2	$ 7.4	$ 2.2
Average AFUDC Rates	8.3%	6.8%	6.4%	7.2%	6.2%	1.7%	8.4%	7.9%	7.6 %

The Regulated companies' average AFUDC rate is based on a FERC-prescribed formula that produces an average rate using the cost of a company's short-term financings as well as a company's capitalization (preferred stock, long-term debt and common equity). The

average rate is applied to average eligible CWIP amounts to calculate AFUDC. AFUDC is recorded on 100 percent of CL&P's and WMECO's CWIP for their NEEWS projects, all of which is being reserved as a regulatory liability to reflect current rate base recovery for 100 percent of the CWIP as a result of FERC-approved transmission incentives. For the year ended December 31, 2008, 50 percent of AFUDC related to other major transmission projects at CL&P were being reserved as a regulatory liability to reflect current rate base recovery for 50 percent of the CWIP as a result of FERC-approved transmission incentives.

P.

Other Income, Net

The pre-tax components of other income/(loss) items are as follows:

NU	**For the Years Ended December 31,**		
(Millions of Dollars)	**2010**	**2009**	**2008**
Other Income:			
Investment Income	$ 6.4	$ 10.1	$ 6.6
Interest Income	4.0	5.6	10.1
AFUDC - Equity Funds	16.7	9.4	29.0
EIA Incentives	8.7	6.1	12.1
C&LM Incentives	7.2	4.3	4.8
Other	2.2	2.7	2.7
Total Other Income	45.2	38.2	65.3
Other Loss:			
Investment Loss	-	-	(14.6)
Other	(3.3)	(0.4)	(0.3)
Total Other Loss	(3.3)	(0.4)	(14.9)
Total Other Income, Net	$ 41.9	$ 37.8	$ 50.4

	For the Years Ended December 31,								
	2010			**2009**			**2008**		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Other Income:									
Investment Income	$ 4.3	$ 1.0	$ 0.9	$ 6.8	$ 1.7	$ 1.5	$ 6.0	$ 1.9	$ 1.2
Interest Income	3.4	1.0	0.6	3.5	2.2	(0.3)	6.4	1.9	1.1
AFUDC - Equity Funds	4.9	10.4	0.6	5.7	3.6	-	23.2	4.4	1.2
EIA Incentives	8.7	-	-	6.1	-	-	12.1	-	-
C&LM Incentives	5.0	1.7	0.5	2.3	1.5	0.5	3.0	1.3	0.5

Other	0.5	0.1	-	1.6	0.5	0.2	1.1	0.2	0.1
Total Other Income	26.8	14.2	2.6	26.0	9.5	1.9	51.8	9.7	4.1
Other Loss:									
Investment Loss	-	-	-	-	-	-	(9.8)	(2.4)	(2.1)
Other	(0.1)	(2.5)	-	(0.1)	-	(0.1)	(0.1)	-	-
Total Other Loss	(0.1)	(2.5)	-	(0.1)	-	(0.1)	(9.9)	(2.4)	(2.1)
Total Other Income, Net	$ 26.7	$ 11.7	$ 2.6	$ 25.9	$ 9.5	$ 1.8	$ 41.9	$ 7.3	$ 2.0

Other Income - Other includes equity in earnings, which relates to the Company's investments, including investments of CL&P, PSNH and WMECO, in the Yankee Companies and NU's investments in two regional transmission companies. For the years ended December 31, 2010, 2009, and 2008, equity in earnings was $1.4 million, $1.8 million and $1.6 million, respectively, for NU. For the year ended December 31, 2010, CL&P, PSNH and WMECO had de minimis amounts for equity in earnings. Equity in earnings was $0.3 million for CL&P and $0.1 million for PSNH and WMECO for both the years ended December 31, 2009 and 2008. For the years ended December 31, 2010, 2009 and 2008, income tax expense associated with the equity in earnings was $0.6 million, $0.7 million and $0.6 million, respectively, for NU (de minimis amounts for CL&P, PSNH and WMECO for all periods presented).

The EIA incentives relate to incentives earned by Connecticut regulated companies from the construction of distributed generation, new large-scale generation and implementation of C&LM initiatives to reduce FMCC charges.

Included in Other Loss - Other for NU and PSNH for the year ended December 31, 2010 is a $2.5 million write-off of carrying charges related to storm costs incurred during the December 2008 ice storm. This write-off was part of PSNH's multi-year rate case settlement agreement that was effective July 1, 2010.

For further information regarding interest income related to federal tax settlements, see Note 11, "Income Taxes," to the consolidated financial statements.

Q.

Other Taxes

Certain excise taxes levied by state or local governments are collected by CL&P and Yankee Gas from their respective customers. These excise taxes are shown on a gross basis with collections in revenues and payments in expenses. Gross receipts taxes, franchise taxes and other excise taxes were included in Operating Revenues and Taxes Other Than Income Taxes on the accompanying consolidated statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2010**	**2009**	**2008**
NU	$ 143.7	$ 135.6	$ 126.6
CL&P	128.0	119.0	107.2

Certain sales taxes are also collected by CL&P, WMECO, and Yankee Gas from their respective customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying consolidated statements of income.

R.

Supplemental Cash Flow Information

	For the Years Ended December 31,		
	2010	**2009**	**2008**
(Millions of Dollars)	**NU**	**NU**	**NU**
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 258.3	$ 263.8	$ 261.4
Income Taxes	84.5	35.1	(36.1)
Non-Cash Investing Activities:			
Capital Expenditures Incurred But Not Paid	127.9	125.5	132.8

	For the Years Ended December 31,								
		2010			**2009**			**2008**	
	CL&P	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
(Millions of Dollars)									
Cash Paid/(Received) During the Year for:									
Interest, Net of Amounts Capitalized	$ 142.2	$ 51.4	$ 20.2	$ 146.7	$ 49.0	$ 19.4	$ 145.5	$ 50.0	$ 20.0
Income Taxes	71.5	1.6	5.0	42.4	12.8	(9.1)	(20.6)	1.0	(5.9)
Non-Cash Investing Activities:									
Capital Expenditures Incurred But Not Paid	46.2	35.8	21.2	48.2	46.5	10.3	76.1	31.4	11.5

Regulatory Overrecoveries/(Refunds and Underrecoveries) on the accompanying consolidated statements of cash flows represents the year-over-year change in regulatory assets and regulatory liabilities, net of amortization charged during the year and other adjustments for non-cash items. These deferred amounts are expected to be recovered from or refunded to customers through the rate-making process and are generally short-term in nature.

The majority of the short-term borrowings of NU, including CL&P, PSNH and WMECO, have original maturities of three months or less. Accordingly, borrowings and repayments are shown net on the statement of cash flows. In December 2008, NU borrowed $127 million under its revolving credit agreement that had original maturities in excess of 90 days. These amounts were repaid in March 2009 and are included in the net activity in the statement of cash flows. In 2010, 2009 and 2008, NU, CL&P, PSNH and WMECO had no other such borrowings.

S.

Self-Insurance Accruals

NU, including CL&P, PSNH and WMECO, are self-insured for employee medical coverage, long-term disability coverage and general liability coverage and up to certain limits for workers compensation coverage. Liabilities for insurance claims include accruals of estimated settlements for known claims, as well as accruals of estimates of incurred but not reported claims. These accruals are included in Other Long-Term Liabilities on the accompanying consolidated balance sheets. In estimating these costs, NU considers historical loss experience and makes judgments about the expected levels of costs per claim. These claims are accounted for based on estimates of the undiscounted claims, including those claims incurred but not reported.

T.

Related Parties

Several wholly-owned subsidiaries of NU provide support services for NU, including CL&P, PSNH and WMECO. NUSCO provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. RRR and Properties, Inc., two other NU subsidiaries, construct, acquire or lease some of the property and facilities used by NU's companies.

As of both December 31, 2010 and 2009, CL&P, PSNH and WMECO had long-term receivables from NUSCO in the amount of $25 million, $3.8 million and $5.5 million, respectively, which are included in Other Long-Term Assets on the accompanying consolidated balance sheets related to the funding of investments held in trust by NUSCO in connection with certain postretirement benefits for CL&P, PSNH and WMECO employees. These amounts have been eliminated in consolidation on the NU financial statements.

Included in the CL&P, PSNH and WMECO consolidated balance sheets as of December 31, 2010 and 2009 are Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, PSNH and WMECO and other subsidiaries that are wholly-owned by NU. As of December 31, 2010 and 2009, CL&P, PSNH and WMECO had a de minimis amount of tax payments accrued in Accounts Payable to Affiliated Companies related to the estimated quarterly income tax obligation paid in the following quarter. These amounts have been eliminated in consolidation on the NU financial statements.

The NU Foundation is an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the NU Foundation consists of certain NU officers. The NU Foundation is not included in the consolidated financial statements of NU as it is a not-for-profit entity and the Company does not have title to the NU Foundation's assets and cannot receive contributions back from the NU Foundation. NU made contributions to the NU Foundation of $1 million in 2010. The operating companies (CL&P, PSNH, WMECO and Yankee) made contributions totaling $1 million in January 2011, which have been recorded as payables in December 2010 ($0.6 million for CL&P, $0.2 million for PSNH and $0.1 million for WMECO). NU did not make any contributions to the NU Foundation in 2009 and 2008.

2.

REGULATORY ACCOUNTING

The Regulated companies continue to be rate-regulated on a cost-of-service basis, therefore, 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.

Management believes it is probable that the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning a return, except for the majority of deferred benefit cost assets, regulatory assets offsetting derivative liabilities, securitized regulatory assets and income tax regulatory assets, all of which are not in rate base. Amortization and deferrals of regulatory assets/(liabilities) are primarily included on a net basis in Amortization of Regulatory Assets/(Liabilities), Net on the accompanying consolidated statements of income.

Regulatory Assets: The components of regulatory assets are as follows:

	As of December 31,	
	2010	**2009**
(Millions of Dollars)	**NU**	**NU**
Deferred Benefit Costs	$ 1,094.2	$ 1,132.1
Regulatory Assets Offsetting Derivative Liabilities	859.7	855.6
Securitized Assets	171.7	432.9
Income Taxes, Net	401.5	363.2
Unrecovered Contractual Obligations	123.2	149.5
Regulatory Tracker Deferrals	70.3	104.1
Storm Cost Deferrals	60.1	60.0
Asset Retirement Obligations	45.3	42.9
Losses On Reacquired Debt	21.5	24.0
Deferred Environmental Remediation Costs	36.8	24.6
Deferred Operation and Maintenance Costs	29.5	-

Other Regulatory Assets		81.5		56.0
Totals	$	2,995.3	$	3,244.9

	As of December 31,					
		2010			2009	
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred Benefit Costs	$ 471.8	$ 152.6	$ 96.0	$ 502.4	$ 154.2	$ 104.9
Regulatory Assets Offsetting Derivative Liabilities	846.2	12.8	-	828.6	26.4	-
Securitized Assets	-	129.8	41.9	195.4	180.1	57.4
Income Taxes, Net	328.9	31.4	16.8	304.1	21.9	16.9
Unrecovered Contractual Obligations	97.9	-	25.3	118.0	-	31.5
Regulatory Tracker Deferrals	35.5	14.7	15.2	70.3	19.0	11.3
Storm Cost Deferrals	4.0	40.7	15.4	-	50.8	9.2
Asset Retirement Obligations	24.9	14.7	3.0	23.8	14.0	2.8
Losses On Reacquired Debt	11.2	8.4	0.4	12.7	9.2	0.4
Deferred Environmental Remediation Costs	-	9.7	-	-	1.3	-
Deferred Operation and Maintenance Costs	29.5	-	-	-	-	-
Other Regulatory Assets	29.0	19.6	13.1	13.5	17.2	6.4
Totals	$ 1,878.9	$ 434.4	$ 227.1	$ 2,068.8	$ 494.1	$ 240.8

Additionally, the Regulated companies had $37.5 million ($0.6 million for CL&P, $26.5 for PSNH, and $1.9 million for WMECO) and $27.1 million ($9.9 million for CL&P and $9.1 million for WMECO) of regulatory costs as of December 31, 2010 and 2009, respectively, which were included in Other Long-Term Assets on the accompanying consolidated balance sheets. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are probable of recovery in future cost-of-service regulated rates.

Of the total December 31, 2010 amount, $6.6 million for PSNH relates to the probable recovery in future rates of previously recognized tax benefits lost as a result of a provision in the 2010 Healthcare Act that eliminated the tax deductibility of actuarially equivalent Medicare Part D benefits for retirees. On July 28, 2010, the DPUC allowed CL&P the creation of a regulatory asset for the recovery of future tax benefits lost as a result of the 2010 Healthcare Act, subject to review in its next rate case. On January 31, 2011, the DPU also allowed WMECO the creation of a regulatory asset as a result of the 2010 Healthcare Act. NU has concluded that these costs are probable of recovery and has recorded regulatory assets of $22 million ($15.5 million for CL&P, $3.9 million for WMECO and $2.6 million for Yankee Gas) as of December 31, 2010, which are reflected in Other Regulatory Assets in the table above. These assets are not earning a return. For further information regarding the 2010 Healthcare Act, see Note 11, "Income Taxes," to the consolidated financial statements. The December 31, 2010 balance at PSNH also includes $19.9 million of costs incurred for the February 2010

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winter storm restorations that met the NHPUC specified criteria for deferral to a major storm cost reserve. PSNH expects to request recovery of both the Medicare asset and the 2010 winter storm costs in 2011.

Deferred Benefit Costs: NU's Pension, SERP, and PBOP Plans are accounted for in accordance with accounting guidance on defined benefit pension and other postretirement plans. Under this accounting guidance, the funded status of its pension and PBOP plans is recorded with an offset to Accumulated Other Comprehensive Income/(Loss) and is remeasured annually. However, because the Regulated companies are rate-regulated on a cost-of-service basis, offsets were recorded as regulatory assets as of December 31, 2010 and 2009 as these amounts have been and continue to be recoverable in cost-of-service regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the Regulated companies, as these amounts are also recoverable. The deferred benefit costs of CL&P and PSNH are not in rate base and are expected to be amortized into expense over a period of up to 12 years. WMECO's deferred benefit costs are earning an equity return at the same rate as the assets included in rate base.

Regulatory Assets Offsetting Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. Included in these amounts are $779 million and $768.7 million as of December 31, 2010 and 2009, respectively, of derivative liabilities relating to CL&P's capacity contracts, referred to as CfDs. See Note 4, "Derivative Instruments," to the consolidated financial statements for further information. These assets are excluded from rate base and are being recovered as the actual settlement occurs over the duration of the contracts.

Securitized Assets: In March 2001, CL&P issued approximately $1.4 billion in RRBs. CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with IPPs. The CL&P securitized asset balance was fully amortized as of December 31, 2010. As of December 31, 2009, the unamortized CL&P securitized asset balance was $167 million, which included $23.2 million related to unrecovered contractual obligations. CL&P also used the proceeds from the issuance of the RRBs to securitize a portion of its regulatory assets associated with income taxes. The securitized income tax regulatory asset was fully amortized as of December 31, 2010 and had an unamortized balance of $28.4 million as of December 31, 2009.

In April 2001, PSNH issued RRBs in the amount of $525 million. PSNH used the majority of the proceeds from that issuance to buydown its power contracts with an affiliate, North Atlantic Energy Corporation. In May 2001, WMECO issued $155 million in RRBs and used the majority of the proceeds from that issuance to buyout an IPP contract.

Securitized regulatory assets are not earning an equity return and are being recovered over the amortization period of their associated RRBs. PSNH RRBs are scheduled to fully amortize by May 1, 2013 and WMECO RRBs are scheduled to fully amortize by June 1, 2013.

Income Taxes, Net: The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. For further information regarding income taxes, see Note 11, "Income Taxes," to the consolidated financial statements.

Unrecovered Contractual Obligations: Under the terms of contracts with CYAPC, YAEC, and MYAPC, CL&P, PSNH, and WMECO are responsible for their proportionate share of the remaining costs of the nuclear facilities, including decommissioning. A portion of these amounts was recorded as unrecovered contractual obligations regulatory assets as of December 31, 2010 and 2009. A portion of these obligations for CL&P was securitized in 2001 and was included in securitized regulatory assets. The securitized portion of these regulatory assets for CL&P was fully recovered as of December 31, 2010. Remaining amounts for CL&P are earning a return and are being recovered through the CTA. Amounts for WMECO are being recovered without a return along with other stranded costs and are anticipated to be recovered by 2013, the scheduled completion date of stranded cost recovery. Amounts for PSNH were fully recovered by 2006.

Regulatory Tracker Deferrals: Regulatory tracker deferrals are approved rate mechanisms that allow utilities to recover costs in specific business segments through reconcilable tracking mechanisms that are reviewed at least annually by the applicable regulatory commission. Regulatory tracker deferrals are recorded as regulatory assets if unrecovered costs are in excess of collections and are recorded as regulatory liabilities if collections are in excess of costs. The majority of regulatory tracker deferrals are earning a return. The following regulatory tracker deferrals were recorded as either regulatory assets or liabilities as of December 31, 2010 and 2009:

<u>CL&P Tracker Deferrals</u>: The CTA allows CL&P to recover stranded costs, such as securitization costs associated with the RRBs, amortization of regulatory assets, and IPP over market costs. As of December 31, 2010 and 2009, CL&P's CTA was a $35.5 million and $32.2 million regulatory asset, respectively, as CTA unrecovered costs were in excess of CTA collections. As part of the CTA reconciliation process, CL&P has also established an obligation to potentially refund the variable incentive portion of its transition service procurement fee, which totaled $24.7 million and $23.2 million as of December 31, 2010 and 2009, respectively, and was recorded as a regulatory liability.

The GSC allows CL&P to recover the costs of the procurement of energy for SS and LRS. The FMCC mechanism allows CL&P to recover the costs of congestion and other costs associated with power market rules approved by the FERC or as approved by the DPUC. CL&P's GSC and FMCC were recorded as a $0.3 million regulatory liability as of December 31, 2010 and a $2.4 million regulatory asset as of December 31, 2009. The SBC allows CL&P to recover certain regulatory and energy public policy costs, such as

hardship protection costs and transition period property taxes. As of December 31, 2010, SBC overrcollections totaled $4.8 million and was recorded as a regulatory liability whereas as of December 31, 2009, SBC undercollections totaled $18 million and was recorded as a regulatory asset. The C&LM charge allows CL&P to recover the costs of C&LM programs. C&LM overcollections totaled $36.4 million and $32.8 million and were recorded as regulatory liabilities as of December 31, 2010 and 2009, respectively. As of December 31, 2010, CL&P retail transmission collections were in excess of costs and $13.2 million was recorded as a regulatory liability whereas as of December 31, 2009, retail transmission costs were in excess of collections and $17.7 million was recorded as a regulatory asset.

PSNH Tracker Deferrals: The NHPUC permits PSNH to recover the actual and prudent costs of providing generation for ES, subject to annual review. Accordingly, ES revenues and costs are fully tracked, and the difference between ES revenues and costs are deferred. ES deferrals are being collected from/refunded to customers through a charge/(credit) in the subsequent ES rate period. As of December 31, 2010 and 2009, the ES deferral was in an underrecovery position of $14.7 million and $8.4 million, respectively and was recorded as a regulatory asset. The SCRC allows PSNH to recover restructuring costs as a result of deregulation and the TCAM covers retail transmission costs incurred by PSNH's distribution business. As of December 31, 2010, SCRC overcollections totaled $2.4 million and TCAM overcollections totaled $0.8 million whereas as of December 31, 2009, SCRC undercollections totaled $3.9 million and TCAM undercollections totaled $6.7 million. PSNH recovers the cost of C&LM programs and C&LM overcollections totaled $3.4 million and $4.4 million as of December 31, 2010 and 2009, respectively.

WMECO Tracker Deferrals: The basic service rate allows WMECO to recover the costs of the procurement of energy for basic service. Basic service undercollections totaled $0.1 million and overcollections totaled $2.1 million as of December 31, 2010 and 2009, respectively. WMECO recovers its stranded costs through a transition charge. This amount represents the cumulative excess of transition expenses over transition revenues. Transition charge undercollections totaled $0.6 million and $6.9 million, and were recorded as a regulatory asset as of December 31, 2010 and 2009, respectively. The C&LM charge allows WMECO to recover the costs of C&LM programs. C&LM undercollections totaled $4.5 million and $2.5 million and were recorded as a regulatory asset as of December 31, 2010 and 2009, respectively. As of December 31, 2010, WMECO retail transmission collections were in excess of costs and $4.8 million was recorded as a regulatory liability whereas, as of December 31, 2009, WMECO retail transmission costs were in excess of collections and $0.9 million was recorded as a regulatory asset.

WMECO's pension and PBOP plan costs are recovered through a tracking mechanism that allows WMECO to earn a return on its pension and PBOP assets and liabilities at its weighted average cost of capital, including the deferred future pension and PBOP benefit obligations. As of December 31, 2010 and 2009, pension/PBOP undercollections totaled $4.6 million and $1 million, respectively, and were recorded as a regulatory asset as the pension/PBOP expenses exceeded the revenue collected from customers.

Storm Cost Deferrals: The storm cost deferrals relate to costs incurred at CL&P, PSNH and WMECO for restorations that met regulatory agency specified criteria for deferral to a major storm cost reserve. The PSNH deferral as of

December 31, 2010 relates to remaining costs incurred for a major storm in December 2008. As part of a multi-year rate case settlement agreement effective July 1, 2010, PSNH was allowed recovery of these storm costs. WMECO's 2008 and 2010 storm costs were deferred and in accordance with WMECO's January 31, 2011 distribution rate case decision will be recovered from customers over five years as part of WMECO's storm reserve. These assets are included in rate base.

The CL&P deferral as of December 31, 2010 relates to remaining costs incurred for the March 2010 winter storm restorations that met the DPUC criteria for a major storm. CL&P is allowed to collect from customers $3 million per year for major storm costs. Storm cost deferrals/reserves are included in rate base.

Asset Retirement Obligations: See Note 6, "Asset Retirement Obligations," to the consolidated financial statements for further information.

Losses on Reacquired Debt: The regulatory asset relates to the losses associated with the reacquisition or redemption of long-term debt. These deferred losses are amortized over the life of the respective long-term debt issuance.

Deferred Environmental Remediation Costs: This regulatory asset relates to environmental remediation costs at PSNH of $9.7 million and Yankee Gas of $27.1 million. Both PSNH and Yankee Gas have regulatory rate recovery mechanisms for environmental costs and accordingly, offsets to environmental reserves were recorded as regulatory assets. Management continues to believe these costs are probable of recovery in future cost-of-service regulated rates.

Deferred Operation and Maintenance Costs: This regulatory asset represents the deferral of maintenance expense in connection with the deferred recovery of revenue requirements for the period July 1, 2010 through December 31, 2010, as allowed by the DPUC. CL&P is allowed to recover these costs beginning January 1, 2011 through June 2012.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

	As of December 31,	
	2010	2009
(Millions of Dollars)	NU	NU
Cost of Removal	$ 194.8	$ 209.2
Regulatory Liabilities Offsetting Derivative Assets	38.1	109.4
Regulatory Tracker Deferrals	95.1	69.5
AFUDC Transmission Incentive	62.1	51.1
Pension Liability - Yankee Gas Acquisition	12.5	15.0
Other Regulatory Liabilities	36.5	31.5
Totals	$ 439.1	$ 485.7

	As of December 31,					
	2010			2009		
(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Cost of Removal	$ 78.6	$ 57.3	$ 9.5	$ 82.2	$ 60.5	$ 16.6
Regulatory Liabilities Offsetting Derivative Assets	38.1	-	-	109.0	0.4	-
Regulatory Tracker Deferrals	79.4	6.6	4.8	56.0	4.4	2.1
AFUDC Transmission Incentive	56.5	-	5.6	50.4	-	0.7
WMECO Provision For Rate Refunds	-	-	2.0	-	-	2.0
Other Regulatory Liabilities	29.5	3.1	1.1	18.6	4.6	0.3
Totals	$ 282.1	$ 67.0	$ 23.0	$ 316.2	$ 69.9	$ 21.7

Cost of Removal: NU's Regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. These amounts are classified as Regulatory Liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Regulatory Liabilities Offsetting Derivative Assets: The regulatory liabilities offsetting derivative assets relate to the fair value of contracts used to purchase power and other related contracts that will benefit customers in the future. See Note 4, "Derivative Instruments," to the consolidated financial statements for further information. This liability is excluded from rate base and is refunded as the actual settlement occurs over the duration of the contracts.

AFUDC Transmission Incentive: See Note 1O, "Summary of Significant Accounting Policies - Allowance for Funds Used During Construction," to the consolidated financial statements for further information.

Pension Liability - Yankee Gas Acquisition: When Yankee Gas was acquired by NU, the pension liability was adjusted to fair value with offsets to the adjustment recorded as a regulatory liability, as approved by the DPUC. The pension liability was approved for amortization over an approximate 13-year period beginning in 2002 without a return on the liability.

WMECO Provision for Rate Refunds: The provision for rate refunds was established to reserve a refund to customers as a result of DPU service quality penalty guidelines.

3.

PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

The following tables summarize the NU, CL&P, PSNH, and WMECO investments in utility plant:

	As of December 31,			
		2010		**2009**
(Millions of Dollars)		**NU**		**NU**
Distribution - Electric	$	6,197.2	$	5,893.9
Distribution - Natural Gas		1,126.6		1,071.1
Transmission		3,378.0		3,219.2
Generation		697.1		660.1
Electric and Natural Gas Utility		11,398.9		10,844.3
Other [(1)]		305.5		265.6
Total Property, Plant and Equipment, Gross		11,704.4		11,109.9
Less: Accumulated Depreciation				
Electric and Natural Gas Utility		(2,862.3)		(2,721.3)
Other		(119.9)		(120.3)
Total Accumulated Depreciation		(2,982.2)		(2,841.6)
Property, Plant and Equipment, Net		8,722.2		8,268.3
Construction Work in Progress		845.5		571.7
Total Property, Plant and Equipment, Net	$	9,567.7	$	8,840.0

(1)

These assets are primarily owned by RRR ($166 million and $143.8 million) and NUSCO ($126.6 million and $109 million) as of December 31, 2010 and 2009, respectively, and are mainly comprised of building improvements at RRR and software and equipment at NUSCO.

	As of December 31,					
	2010			2009		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Distribution	$ 4,180.7	$ 1,375.4	$ 673.7	$ 3,960.1	$ 1,309.2	$ 654.9
Transmission	2,668.4	476.1	233.5	2,573.2	450.2	195.7
Generation	-	687.7	9.4	-	660.1	-
Total Property, Plant and Equipment, Gross	6,849.1	2,539.2	916.6	6,533.3	2,419.5	850.6
Less: Accumulated Depreciation	(1,508.7)	(837.3)	(228.5)	(1,426.6)	(805.5)	(218.2)
Property, Plant and Equipment, Net	5,340.4	1,701.9	688.1	5,106.7	1,614.0	632.4
Construction Work in Progress	246.1	351.4	129.0	233.9	200.7	73.4
Total Property, Plant and Equipment, Net	$ 5,586.5	$ 2,053.3	$ 817.1	$ 5,340.6	$ 1,814.7	$ 705.8

PSNH charges planned major maintenance activities to Operating Expenses unless the cost represents the acquisition of additional components. PSNH capitalizes the cost of plant additions.

CL&P, PSNH and WMECO have entered into certain equipment purchase contracts that require the Company to make advance payments during the design, manufacturing, shipment and installation of equipment. As of December 31, 2010 and 2009, advance payments totaling $9.3 million and $27 million, respectively ($1.3 million and $5.4 million for CL&P, $4.9 million and $16.6 million for PSNH and $3.1 million and $5 million for WMECO, respectively) are included within CWIP in the table above and not subject to depreciation.

The following table summarizes average depreciable lives as of December 31, 2010:

	Average Depreciable Life			
(Years)	**NU**	**CL&P**	**PSNH**	**WMECO**
Distribution	36.8	36.0	37.0	32.5
Transmission	43.2	42.3	44.6	54.2
Generation	31.9	-	31.6	25.0
Other	20.7	-	-	-

The provision for depreciation on utility assets is calculated using the straight-line method based on the estimated remaining useful lives of depreciable plant in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency (the DPUC, NHPUC, and the DPU for CL&P, PSNH, and WMECO, respectively). Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation, which includes cost of removal less salvage. Cost of removal is classified as a Regulatory Liability on the accompanying consolidated balance sheets. The depreciation rates for the several classes of utility plant-in-service are equivalent to composite rates as follows:

(Percent)	**2010**	**2009**	**2008**
NU	2.7	2.9	3.0
CL&P	2.7	3.0	3.1
PSNH	2.8	2.7	2.7
WMECO	2.8	2.9	2.8

4.

DERIVATIVE INSTRUMENTS

The costs and benefits of derivative contracts that meet the definition of and are designated as "normal purchases or normal sales" (normal) are recognized in Operating Expenses or Operating Revenues on the accompanying consolidated statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not recorded as normal under the applicable accounting guidance, are recorded at fair value as current or long-term derivative assets or liabilities. Changes in fair values of NU Enterprises' derivatives are included in Net Income. For the Regulated companies, regulatory assets or liabilities are recorded for the changes in fair values of derivatives, as these contracts are part of current regulated operating costs, or have an allowed recovery mechanism, and management believes that these costs will continue to be recovered from or refunded to customers in cost-of-service, regulated rates. See below for discussion of "Derivatives not designated as hedges."

The Regulated companies are exposed to the volatility of the prices of energy and energy-related products in procuring energy supply for their customers. The costs associated with supplying energy to customers are recoverable through customer rates. The Company manages the risks associated with the price volatility of energy and energy-related products through the use of derivative contracts, many of which are accounted for as normal (for WMECO all derivative contracts are accounted for as normal) and the use of nonderivative contracts.

CL&P mitigates the risks associated with the price volatility of energy and energy-related products through the use of SS or LRS contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to three years and are accounted for as normal. CL&P has entered into derivatives, including FTR contracts and bilateral basis swaps, to manage the risk of congestion costs associated with its SS and LRS contracts. As required by regulation, CL&P has also entered into derivative and

nonderivative contracts for the purchase of energy and energy-related products and contracts related to capacity. While the risks managed by these contracts are regional congestion costs and capacity price risks that are not specific to CL&P, Connecticut's electric distribution companies, including CL&P, are required to enter into these contracts. Management believes any costs or benefits from these contracts are recoverable from or will be refunded to CL&P's customers, and, therefore any changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying consolidated balance sheets.

WMECO mitigates the risks associated with the volatility of the prices of energy and energy-related products in procuring energy supply for its customers through the use of basic service contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to three years and are accounted for as normal.

PSNH mitigates the risks associated with the volatility of energy prices in procuring energy supply for its customers through its generation facilities and the use of derivative contracts, including energy forward contracts, options and FTRs. PSNH enters into these contracts in order to stabilize electricity prices for customers. Management believes any costs or benefits from these contracts are recoverable from or will be refunded to PSNH's customers, and, therefore any changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying consolidated balance sheets.

NU, through Yankee Gas, mitigates the risks associated with supply availability and volatility of natural gas prices through the use of storage facilities and agreements to purchase natural gas supply for customers. The costs associated with mitigating these risks are recoverable from customers, and, therefore any changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying consolidated balance sheets.

NU Enterprises, through Select Energy, has one remaining fixed price forward sales contract to serve electrical load that is part of its wholesale energy marketing portfolio. NU Enterprises mitigates the price risk associated with this contract through the use of forward purchase and sales contracts. NU Enterprises' derivative contracts are accounted for at fair value, and changes in their fair values are recorded in Operating Expenses on the accompanying consolidated statements of income.

NU is also exposed to interest rate risk associated with its long-term debt. From time to time, various subsidiaries of the Company enter into forward starting interest rate swaps, accounted for as cash flow hedges, to mitigate the risk of changes in interest rates when they expect to issue long-term debt. NU parent has also entered into an interest rate swap on fixed rate long-term debt in order to manage the balance of its fixed and floating rate debt. This interest rate swap is accounted for as a fair value hedge.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with appropriate current and long-term portions, in the accompanying consolidated balance sheets. The following tables present the gross fair values of contracts and the net amounts recorded as current or long-term derivative assets or liabilities, by primary underlying risk exposures or purpose:

	As of December 31, 2010					
	Derivatives Not Designated as Hedges					
(Millions of Dollars)	**Commodity and Capacity Contracts Required by Regulation**	**Commodity Sales Contract and Related Price and Supply Risk Management**	**Other Commodity Price and Supply Risk Management**	**Hedging Instruments-Interest Rate Risk Management**	**Collateral and Netting**	**Net Amount Recorded as Derivative Asset/(Liability)**
Current Derivative Assets:						
Level 2:						
NU Parent	$ -	$ -	$ -	$ 7.7	$ -	$ 7.7
Level 3:						
NU Enterprises	-	1.7	-	-	-	1.7
CL&P	5.8	-	2.1	-	-	7.9
Total Current Derivative Assets	$ 5.8	$ 1.7	$ 2.1	$ 7.7	$ -	$ 17.3
Long-Term Derivative Assets:						
Level 2:						
NU Parent	$ -	$ -	$ -	$ 4.1	$ -	$ 4.1
Level 3:						
NU Enterprises	-	3.2	-	-	-	3.2
CL&P (1)	195.9	-	-	-	(80.0)	115.9
Total Long-Term Derivative Assets	$ 195.9	$ 3.2	$ -	$ 4.1	$ (80.0)	$ 123.2
Current Derivative Liabilities:						
Level 2:						
PSNH	$ -	$ -	$ (12.8)	$ -	$ -	$ (12.8)
Level 3:						
NU Enterprises (2)	-	(11.9)	-	-	0.5	(11.4)
CL&P (1)	(54.3)	-	(0.2)	-	7.7	(46.8)
Other	-	-	(0.5)	-	-	(0.5)
	$ (54.3)	$ (11.9)	$ (13.5)	$ -	$ 8.2	$ (71.5)

Total Current Derivative Liabilities												
Long-Term Derivative Liabilities:												
Level 3:												
NU Enterprises [1]	$	-	$	(26.5)	$	-	$	-	$	0.2	$	(26.3)
CL&P		(883.1)		-		-		-		-		(883.1)
Other		-		-		(0.3)		-		-		(0.3)
Total Long-Term Derivative Liabilities	$	(883.1)	$	(26.5)	$	(0.3)	$	-	$	0.2	$	(909.7)

	As of December 31, 2009					
	Derivatives Not Designated as Hedges					
(Millions of Dollars)	Commodity and Capacity Contracts Required by Regulation	Commodity Sales Contract and Related Price and Supply Risk Management	Other Commodity Price and Supply Risk Management	Hedging Instruments-Interest Rate Risk Management	Collateral and Netting	Net Amount Recorded as Derivative Asset/(Liability)
Current Derivative Assets:						
Level 2:						
NU Parent	$ -	$ -	$ -	$ 6.7	$ -	$ 6.7
Level 3:						
CL&P	20.1	-	4.5	-	-	24.6
PSNH [3]	-	-	0.4	-	-	0.4
Other	-	-	0.1	-	-	0.1
Total Current Derivative Assets	$ 20.1	$ -	$ 5.0	$ 6.7	$ -	$ 31.8
Long-Term Derivative Assets:						
Level 2:						
NU Parent	$ -	$ -	$ -	$ 6.5	$ -	$ 6.5
Level 3:						
CL&P [1]	259.0	-	-	-	(75.8)	183.2
Total Long-Term Derivative Assets	$ 259.0	$ -	$ -	$ 6.5	$ (75.8)	$ 189.7
Current Derivative Liabilities:						
Level 2:						
PSNH	$ -	$ -	$ (18.8)	$ -	$ -	$ (18.8)
Level 3:						
NU Enterprises [2]	-	(13.0)	-	-	4.3	(8.7)
CL&P [4]	(10.3)	-	-	-	0.5	(9.8)
Other	-	-	(0.4)	-	-	(0.4)
Total Current Derivative Liabilities	$ (10.3)	$ (13.0)	$ (19.2)	$ -	$ 4.8	$ (37.7)
Long-Term Derivative Liabilities:						
Level 2:						

PSNH	$	-	$	-	$	(7.6)	$	-	$	-	$	(7.6)
Level 3:												
NU Enterprises [1]		-		(41.1)		-		-		6.7		(34.4)
CL&P		(913.3)		-		-		-		-		(913.3)
Other		-		-		(0.3)		-		-		(0.3)
Total Long-Term Derivative Liabilities	$	(913.3)	$	(41.1)	$	(7.9)	$	-	$	6.7	$	(955.6)

(1)

Amounts in Collateral and Netting represent derivative contracts that are netted against the fair value of the gross derivative asset/liability.

(2)

Collateral and Netting amounts as of December 31, 2010 for NU Enterprises current derivative liabilities represent cash collateral posted that is under master netting agreements. As of December 31, 2009, Collateral and Netting included derivative assets of $2.2 million that are netted against the fair value of derivative liabilities and cash collateral of $2.1 million posted under master netting agreements.

(3)

On PSNH's accompanying consolidated balance sheet, the current portion of the net derivative asset is shown in Prepayments and Other Current Assets.

(4)

Collateral and Netting amounts represent cash posted under master netting agreements.

The business activities of the Company that resulted in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2010, NU's and CL&P's derivative assets are exposed to counterparty credit risk. Of these amounts, $95.5 million ($83.6 million for CL&P) is contracted with investment grade entities and the remainder is contracted with multiple other counterparties.

For further information on the fair value of derivative contracts, see Note 1J, "Summary of Significant Accounting Policies - Derivative Accounting," Note 1I, "Summary of Significant Accounting Policies - Fair Value Measurements."

The following provides additional information about the derivatives included in the tables above, including volumes and cash flow information.

Derivatives not designated as hedges

NU Enterprises' commodity sales contract and related price and supply risk management: As of December 31, 2010 and 2009, NU Enterprises had approximately 0.3 million and 0.4 million MWh, respectively, of supply volumes remaining in its wholesale portfolio when expected sales to an agency that is comprised of municipalities are compared with contracted supply, both of which extend through 2013.

CL&P commodity and capacity contracts required by regulation: As of December 31, 2010 and 2009, CL&P had contracts with two IPPs to purchase electricity monthly in amounts aggregating approximately 1.5 million MWh per year through March 2015 under one of these contracts and 0.1 million MWh per year through December 2020 under the second contract. CL&P also has two capacity-related CfDs to increase energy supply in Connecticut relating to one generating project that has been modified and one generating plant to be built. The total capacity of these CfDs and two additional CfDs entered into by UI is expected to be approximately 787 MW. CL&P has an agreement with UI, which is also accounted for as a derivative, under which UI will share the costs and benefits of the four CfDs, with 80 percent allocated to CL&P and 20 percent to UI. The four CfDs obligate the utilities to pay/receive monthly the difference between a set capacity price and the forward capacity market price that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009.

Commodity price and supply risk management: As of December 31, 2010 and 2009, CL&P had 1.8 million and 2.7 million MWh, respectively, remaining under FTRs that extend through December 2011 and require monthly payments or receipts.

PSNH has electricity procurement contracts with delivery dates through 2011 to purchase an aggregate amount of 0.4 million and 1 million MWh of power as of December 31, 2010 and 2009, respectively, that is used to serve customer load and manage price risk of its electricity delivery service obligations. These contracts are settled monthly. PSNH also has two energy call options that it received in exchange for assigning its transmission rights in a direct current transmission line. The options give PSNH the right to purchase a de minimis amount and 0.6 million MWh of electricity through January 2011 as of December 31, 2010 and 2009, respectively. In addition, PSNH has entered into FTRs to manage the risk of congestion costs associated with its electricity delivery service. As of December 31, 2010 and 2009, there were 0.3 million and 0.4 million MWh, respectively, remaining under FTRs that extend through December 2011 and required monthly payments or receipts. The purpose of the PSNH derivative contracts is to provide stable rates for customers by mitigating price uncertainties associated with the New England electricity spot market.

The following table presents the realized and unrealized gains/(losses) associated with derivative contracts not designated as hedges:

Derivatives Not Designated as Hedges	Location of Gain or Loss Recognized on Derivative	Amount of Gain/(Loss) Recognized on Derivative Instrument For the Years Ended December 31, 2010	December 31, 2009

(Millions of Dollars)			
NU Enterprises:			
Commodity Sales Contract and Related Price and Supply Risk Management	Fuel, Purchased and Net Interchange Power	$ 2.7	$ 6.2
Regulated Companies:			
CL&P Commodity and Capacity Contracts Required by Regulation	Regulatory Assets/Liabilities	(74.0)	(99.9)
Other Commodity Price and Supply Risk Management:			
CL&P	Regulatory Assets/Liabilities	(6.2)	(7.8)
PSNH	Regulatory Assets/Liabilities	(15.0)	(62.6)
Other	Regulatory Assets/Liabilities	(0.5)	(2.8)

For the Regulated companies, monthly settlement amounts are recorded as receivables or payables and as Operating Revenues or Fuel, Purchased and Net Interchange Power on the accompanying consolidated financial statements. Regulatory assets/liabilities are established with no impact to Net Income.

Derivatives designated as hedges

Interest Rate Risk Management: To manage the interest rate risk characteristics of NU parent's fixed rate long-term debt, NU parent has a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate senior notes maturing on April 1, 2012. This interest rate swap qualifies and was designated as a fair value hedge and requires semi-annual cash settlements. The changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in Interest Expense on the accompanying consolidated statements of income. There was no ineffectiveness recorded for the years ended December 31, 2010 and 2009. The cumulative changes in fair values of the swap and the Long-Term Debt are recorded as a Derivative Asset/Liability and an adjustment to Long-Term Debt. Interest receivable is recorded as a reduction of Interest Expense and is included in Prepayments and Other Current Assets.

The realized and unrealized gains/(losses) related to changes in fair value of the swap and Long-Term Debt as well as pre-tax Interest Expense, recorded in Net Income, were as follows:

	For the Years Ended			
	December 31, 2010		December 31, 2009	
	Swap	**Hedged Debt**	**Swap**	**Hedged Debt**
Changes in Fair Value	$ 9.5	$ (9.5)	$ 1.6	$ (1.6)
Interest Recorded in Net Income	-	10.9	-	9.1

There were no cash flow hedges outstanding as of or during the years ended December 31, 2010 and 2009 and no ineffectiveness was recorded during these periods. From time to time, NU, including CL&P, PSNH and WMECO, enters into forward starting interest rate swap agreements on proposed debt issuances that qualify and are designated as cash flow hedges. Cash flow hedges are recorded at fair value, and the changes in the fair value of the effective portion of those contracts are recognized in Accumulated Other Comprehensive Income/(Loss). Cash flow hedges impact Net Income when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is improbable of occurring, or when the transaction is settled. When a cash flow hedge is terminated, the settlement amount is recorded in Accumulated Other Comprehensive Income/(Loss) and is amortized into Net Income over the term of the underlying debt instrument.

Pre-tax gains/(losses) amortized from Accumulated Other Comprehensive Income/(Loss) into Interest Expense on the accompanying consolidated statements of income were as follows:

	For the Years Ended	
(Millions of Dollars)	**December 31, 2010**	**December 31, 2009**
CL&P	$ (0.7)	$ (0.7)
PSNH	(0.2)	(0.2)
WMECO	0.1	0.1
Other	0.4	0.4
NU	$ (0.4)	$ (0.4)

For further information, see Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

Credit Risk

Certain derivative contracts that are accounted for at fair value, including PSNH's electricity procurement contracts and NU Enterprises' electricity sourcing contracts, contain credit risk contingent features. These features require these companies or, in NU Enterprises' case, NU parent, to maintain investment grade credit ratings from the major rating agencies and to post cash or standby LOCs as collateral for contracts in a net liability position over specified credit limits. NU parent provides standby LOCs under its revolving credit agreement for NU subsidiaries to post with counterparties. The following summarizes the fair value of derivative contracts that are in a liability position and subject to credit risk contingent features, and the fair value of cash collateral and standby LOCs posted with counterparties as of December 31, 2010 and 2009:

	As of December 31, 2010					
(Millions of Dollars)		**Fair Value Subject to Credit Risk Contingent Features**		**Cash Collateral Posted**		**Standby LOCs Posted**
PSNH	$	(12.8)	$	-	$	24.0
NU Enterprises		(18.1)		0.5		-
NU	$	(30.9)	$	0.5	$	24.0

	As of December 31, 2009					
(Millions of Dollars)		**Fair Value Subject to Credit Risk Contingent Features**		**Cash Collateral Posted**		**Standby LOCs Posted**
PSNH	$	(26.4)	$	-	$	25.0
NU Enterprises		(20.0)		2.1		-
NU	$	(46.4)	$	2.1	$	25.0

Additional collateral is required to be posted by NU Enterprises or PSNH, if the respective unsecured debt credit ratings of NU parent or PSNH are downgraded below investment grade. As of December 31, 2010, NU Enterprises and PSNH would not have been required to post any additional cash collateral if credit ratings had been downgraded below investment grade. However, if the senior unsecured debt of NU parent had been downgraded to below investment grade, additional standby LOCs in the amount of $18.5 million would have been required to be posted on derivative contracts for Select Energy. As of December 31, 2009, no additional cash collateral would have been required to be posted if credit ratings had been downgraded below investment grade. However, if the senior unsecured debt of PSNH or NU parent had been downgraded to below investment grade, additional standby LOCs in the amount of $1.8 million and $17.8 million would have been required to be posted on derivative contracts for PSNH and Select Energy, respectively.

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

Fair Value Measurements of Derivative Instruments:

Valuation of Derivative Instruments: Derivative contracts classified as Level 2 in the fair value hierarchy include Other Commodity Price and Supply Risk Management contracts and Interest Rate Risk Management contracts. Other Commodity Price and Supply Risk Management contracts include PSNH forward contracts to purchase energy for periods for which prices are quoted in an active market. Prices are obtained from broker quotes and based on actual market activity. The contracts are valued using the mid-point of the bid-ask spread. Valuations of these contracts also incorporate discount rates using the yield curve approach. The Interest Rate Risk Management contract represents an interest rate swap agreement and is valued using a market approach provided by the swap counterparty using a discounted cash flow approach utilizing forward interest rate curves.

The derivative contracts classified as Level 3 in the tables below include NU Enterprises' Sales Contract and Related Price and Supply Risk Management contracts, the Regulated companies' Commodity and Capacity Contracts Required by Regulation (which include CL&P's CfDs and contracts with certain IPPs), and Other Commodity Price and Supply Risk Management contracts (CL&P and PSNH FTRs). For Commodity and Capacity Contracts Required by Regulation and NU Enterprises' Commodity Sales contract, fair value is modeled using income techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices for which quoted prices in an active market exist. Significant unobservable inputs used in the valuations of these contracts include energy and energy-related product prices for future years for long-dated derivative contracts and future contract quantities under requirements and supplemental sales contracts. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts include assumptions regarding the timing and likelihood of scheduled payments and also reflect nonperformance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the company's credit rating for liabilities.

Other Commodity Price and Supply Risk Management contracts classified as Level 3 in the tables below are valued using income approaches. Observable inputs used in valuing options include prices for energy and energy-related products for years for which quoted prices in an active market exist. Unobservable inputs included in the valuation of options contracts include market volatilities related to future energy prices and the estimated likelihood that the option will be exercised. FTRs are valued using broker quotes based on prices in an inactive market.

Valuations using significant unobservable inputs: The following tables present changes for the years ended December 31, 2010 and 2009 in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis. The Company classifies assets and liabilities in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model. In addition to these unobservable inputs, the valuation models for Level 3 assets and liabilities typically also rely on a number of inputs that are observable either directly or indirectly. Thus the gains and losses presented below include changes in fair value that are attributable to both observable and unobservable inputs. There were no transfers into or out of Level 3 assets and liabilities for the years ended December 31, 2010 or 2009:

	For the Year Ended December 31, 2010			
	NU			
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Sales Contract and Related Price and Supply Risk Management**	**Other Commodity Price and Supply Risk Management**	**Total Level 3**
Derivatives, Net:				
Fair Value as of Beginning of Year	$ (720.3)	$ (45.2)	$ 4.3	$ (761.2)
Net Realized/Unrealized Gains/(Losses) Included in:				
Net Income (1)	-	2.7	-	2.7
Regulatory Assets/Liabilities	(74.0)	-	(7.2)	(81.2)
Purchases, Issuances and Settlements	(13.7)	9.2	4.0	(0.5)
Fair Value as of End of Year	$ (808.0)	$ (33.3)	$ 1.1	$ (840.2)
Period Change in Unrealized Gains Included in Net Income Relating to Items Held as of End of Year	$ -	$ 1.2	$ -	$ 1.2

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	For the Year Ended December 31, 2010			
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**CL&P Other Commodity Price and Supply Risk Management**	**Total Level 3**	**PSNH Other Commodity Price and Supply Risk Management**
Derivatives, Net:				
Fair Value as of Beginning of Year	$ (720.3)	$ 4.5	$ (715.8)	$ 0.4
Net Realized/Unrealized Gains/(Losses) Included in:				
Regulatory Assets/Liabilities	(74.0)	(6.2)	(80.2)	(0.2)
Purchases, Issuances and Settlements	(13.7)	3.6	(10.1)	(0.2)
Fair Value as of End of Year	$ (808.0)	$ 1.9	$ (806.1)	$ -

	For the Year Ended December 31, 2009		
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**
Derivatives, Net:			
Fair Value as of Beginning of Year	$ (669.2)	$ (611.1)	$ 4.1
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income [(1)]	6.2	-	-
Regulatory Assets/Liabilities	(114.3)	(107.8)	(3.6)
Purchases, Issuances and Settlements	16.1	3.1	(0.1)
Fair Value as of End of Year	$ (761.2)	$ (715.8)	$ 0.4
Period Change in Unrealized Gains Included in Net Income Relating to Items Held as of End of Year	$ 6.3	$ -	$ -

(1)

Realized and unrealized gains and losses on derivatives included in Net Income relate to the remaining NU Enterprises' marketing contracts and are reported in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income.

5.

MARKETABLE SECURITIES (NU, WMECO)

The Company elected to record exchange traded funds and mutual funds purchased during 2009 in the NU supplemental benefit trust at fair value in order to reflect the economic effect of changes in fair value of all newly purchased equity securities in Net Income.

These equity securities, classified as Level 1 in the fair value hierarchy, totaled $42.2 million and $35.3 million as of December 31,

2010 and 2009, respectively, and are included in current Marketable Securities. Gains on these securities of $6.9 million and $6.6 million for the years ended December 31, 2010 and 2009, respectively, were recorded in Other Income, Net on the accompanying consolidated statements of income. Dividend income is recorded when dividends are declared and are recorded in Other Income, Net on the accompanying consolidated statements of income. All other marketable securities are accounted for as available-for-sale.

Available-for-Sale Securities: The following is a summary by security type of NU's available-for-sale securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. These securities are recorded at fair value and included in current and long-term portions of Marketable Securities on the accompanying consolidated balance sheets.

	As of December 31, 2010							
(Millions of Dollars)		**Amortized Cost**		**Pre-Tax Unrealized Gains [1]**		**Pre-Tax Unrealized Losses [1]**		**Fair Value**
NU Supplemental Benefit Trust								
U.S. Government Issued Debt Securities (Agency and Treasury)	$	11.7	$	0.2	$	(0.1)	$	11.8
Corporate Debt Securities		6.5		0.5		(0.1)		6.9
Asset Backed Debt Securities		6.5		0.4		-		6.9
Municipal Bonds		0.7		-		-		0.7
Money Market Funds and Other		3.7		0.2		-		3.9
Total NU Supplemental Benefit Trust	$	29.1	$	1.3	$	(0.2)	$	30.2
WMECO Spent Nuclear Fuel Trust								
U.S. Government Issued Debt Securities (Agency and Treasury)	$	6.0	$	-	$	-	$	6.0
Corporate Debt Securities		15.6		-		-		15.6
Asset Backed Debt Securities		4.8		-		(0.1)		4.7
Municipal Bonds		15.4		-		-		15.4
Money Market Funds and Other		15.4		-		-		15.4
Total WMECO Spent Nuclear Fuel Trust	$	57.2	$	-	$	(0.1)	$	57.1
Total NU	$	86.3	$	1.3	$	(0.3)	$	87.3

	As of December 31, 2009			
(Millions of Dollars)	**Amortized Cost**	**Pre-Tax Unrealized Gains** [1]	**Pre-Tax Unrealized Losses** [1]	**Fair Value**
NU Supplemental Benefit Trust				
U.S. Government Issued Debt Securities				
(Agency and Treasury)	$ 12.8	$ 0.3	$ (0.2)	$ 12.9
Corporate Debt Securities	7.4	0.4	(0.1)	7.7
Asset Backed Debt Securities	5.2	0.1	(0.1)	5.2
Municipal Bonds	0.2	-	-	0.2
Money Market Funds and Other	3.0	-	-	3.0
Total NU Supplemental Benefit Trust	$ 28.6	$ 0.8	$ (0.4)	$ 29.0
WMECO Spent Nuclear Fuel Trust				
U.S. Government Issued Debt Securities				
(Agency and Treasury)	$ 17.0	$ -	$ -	$ 17.0
Corporate Debt Securities	17.4	0.1	(0.1)	17.4
Asset Backed Debt Securities	1.1	-	(0.2)	0.9
Municipal Bonds	10.6	-	-	10.6
Money Market Funds and Other	10.9	-	-	10.9
Total WMECO Spent Nuclear Fuel Trust	$ 57.0	$ 0.1	$ (0.3)	$ 56.8
Total NU	$ 85.6	$ 0.9	$ (0.7)	$ 85.8

(1)

Unrealized gains and losses on debt securities for the NU supplemental benefit trust and WMECO spent nuclear fuel trust are recorded in Accumulated Other Comprehensive Income/(Loss) and Other Long-Term Assets, respectively, on the accompanying consolidated balance sheets. For information related to the change in unrealized gains and losses for the NU supplemental benefit trust included in Accumulated Other Comprehensive Income/(Loss), see Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

Unrealized Losses and Other-than-Temporary Impairment: There have not been significant unrealized losses, other-than-temporary impairments or credit losses for the NU supplemental benefit trust or WMECO spent nuclear fuel trust. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset backed securities, underlying collateral and expected future cash flows are also evaluated. All but one of the corporate and asset backed securities held in the NU supplemental benefit trust are rated investment grade. All but one of the securities in the WMECO spent nuclear fuel trust are rated investment grade and credit losses have been recorded for those securities that are below investment grade.

Contractual Maturities: As of December 31, 2010, the contractual maturities of available-for-sale debt securities are as follows:

	NU		WMECO	
(Millions of Dollars)	**Amortized Cost**	**Fair Value**	**Amortized Cost**	**Fair Value**
Less than one year	$ 36.0	$ 36.1	$ 33.2	$ 33.2
One to five years	15.1	15.2	9.1	9.1
Six to ten years	6.6	7.0	1.0	1.0
Greater than ten years	28.6	29.0	13.9	13.8
Total Debt Securities	$ 86.3	$ 87.3	$ 57.2	$ 57.1

Sales of Securities: For the years ended December 31, 2010, 2009 and 2008, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

	NU			WMECO		
(Millions of Dollars)	**Realized Gains**	**Realized Losses**	**Net Realized Gains**	**Realized Gains**	**Realized Losses**	**Net Realized Losses**
2010	$ 0.6	$ (0.4)	$ 0.2	$ -	$ (0.2)	$ (0.2)
2009	15.9	(6.2)	9.7	-	(0.8)	(0.8)
2008	2.5	(2.2)	0.3	0.2	(0.6)	(0.4)

Realized gains and losses on available-for-sale securities are recorded in Other Income, Net for the NU supplemental benefit trust and in Other Long-Term Assets for the WMECO spent nuclear fuel trust. NU utilizes the specific identification basis method for the NU supplemental benefit trust securities and the average cost basis method for the WMECO spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities. Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $174.9 million, $208.9 million and $259.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. WMECO's portion of these proceeds totaled $114.2 million, $106.3 million and $169.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. Proceeds from the sales of securities are used to purchase new securities.

For further information regarding marketable securities, see Note 1K, "Summary of Significant Accounting Policies - Marketable Securities," to the consolidated financial statements.

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	NU		WMECO	
(Millions of Dollars)	**As of December 31, 2010**	**As of December 31, 2009**	**As of December 31, 2010**	**As of December 31, 2009**
Level 1:				
Exchange Traded Funds	$ 38.9	$ 32.0	$ -	$ -
High Yield Bond Fund	3.3	3.3	-	-
Money Market Funds	1.8	8.9	0.3	6.6
Total Level 1	44.0	44.2	0.3	6.6
Level 2:				
U.S. Government Issued Debt Securities (Agency and Treasury)	17.8	29.9	6.0	17.0
Corporate Debt Securities	22.5	25.1	15.6	17.4
Asset Backed Debt Securities	11.6	6.1	4.7	0.9
Municipal Bonds	16.1	10.8	15.4	10.6
Other Fixed Income Securities	17.5	5.0	15.1	4.3
Total Level 2	85.5	76.9	56.8	50.2
Total Marketable Securities	$ 129.5	$ 121.1	$ 57.1	$ 56.8

U.S. Government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instrument and also incorporating yield curves, credit spreads and specific bond terms and conditions. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Asset backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and maturity dates and tranche information. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

Not included in the tables above are $0.6 million and $11.6 million of cash equivalents as of December 31, 2010 and 2009, respectively, held by NU parent in an unrestricted money market account and included in Cash and Cash

Equivalents on the accompanying consolidated balance sheets of NU, which are classified as Level 1 in the fair value hierarchy.

6.

ASSET RETIREMENT OBLIGATIONS

In accordance with accounting guidance for conditional AROs, NU, including CL&P, PSNH and WMECO, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. The guidance provides that settlement dates and future costs should be reasonably estimated when sufficient information becomes available and provides direction on the definition and timing of sufficient information in determining expected cash flows and fair values. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination. A fair value calculation, reflecting expected probabilities for settlement scenarios, has been performed.

The fair value of an ARO is recorded as a liability in Other Long-Term Liabilities with an offset included in Property, Plant and Equipment, Net on the accompanying consolidated balance sheets. As the Regulated companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and the costs associated with the Regulated companies' AROs are included in Other Regulatory Assets as of December 31, 2010 and 2009. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. Both the depreciation and accretion were recorded as increases to Regulatory Assets on the accompanying consolidated balance sheets as of December 31, 2010 and 2009.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities as of December 31, 2010 and 2009:

(Millions of Dollars)	As of December 31, 2010				As of December 31, 2009			
NU	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	$ 2.6	$ (1.7)	$ 22.8	$ (25.1)	$ 2.7	$ (1.7)	$ 21.8	$ (23.9)
Hazardous Contamination	4.9	(1.5)	17.3	(21.5)	4.9	(1.4)	16.2	(20.2)
Other AROs	2.4	(1.0)	5.2	(6.7)	2.6	(1.2)	4.9	(6.5)
Total AROs	$ 9.9	$ (4.2)	$ 45.3	$ (53.3)	$ 10.2	$ (4.3)	$ 42.9	$ (50.6)
CL&P								
Asbestos	$ 1.6	$ (1.0)	$ 13.2	$ (13.8)	$ 1.6	$ (1.0)	$ 12.6	$ (13.2)
Hazardous Contamination	3.8	(1.1)	10.1	(12.8)	3.9	(1.1)	9.4	(12.2)
Other AROs	2.0	(0.9)	1.6	(2.7)	2.4	(1.0)	1.8	(3.2)
Total AROs	$ 7.4	$ (3.0)	$ 24.9	$ (29.3)	$ 7.9	$ (3.1)	$ 23.8	$ (28.6)
PSNH								
Asbestos	$ 0.9	$ (0.5)	$ 7.7	$ (9.3)	$ 0.9	$ (0.5)	$ 7.4	$ (8.7)
Hazardous Contamination	0.5	(0.3)	6.2	(7.2)	0.5	(0.3)	5.9	(6.7)
Other AROs	-	-	0.8	(1.1)	-	-	0.7	(1.0)
Total AROs	$ 1.4	$ (0.8)	$ 14.7	$ (17.6)	$ 1.4	$ (0.8)	$ 14.0	$ (16.4)
WMECO								
Asbestos	$ 0.2	$ (0.1)	$ 1.9	$ (2.0)	$ 0.2	$ (0.1)	$ 1.8	$ (1.9)
Hazardous Contamination	0.6	(0.2)	1.1	(1.5)	0.5	(0.1)	1.0	(1.4)
Other AROs	0.1	-	-	(0.1)	-	-	-	-
Total AROs	$ 0.9	$ (0.3)	$ 3.0	$ (3.6)	$ 0.7	$ (0.2)	$ 2.8	$ (3.3)

A reconciliation of the beginning and ending carrying amounts of Regulated companies' ARO liabilities are as follows:

	As of December 31,	
	2010	2009
(Millions of Dollars)	NU	NU
Balance as of Beginning of Year	$ (50.6)	$ (50.6)

Liabilities Incurred During the Year		(0.2)		-
Liabilities Settled During the Year		1.2		2.3
Accretion		(3.3)		(3.3)
Revisions in Estimated Cash Flows		(0.4)		1.0
Balance as of End of Year	$	(53.3)	$	(50.6)

	As of December 31,											
	2010						2009					
(Millions of Dollars)	**CL&P**		**PSNH**		**WMECO**		**CL&P**		**PSNH**		**WMECO**	
Balance as of Beginning of Year	$	(28.6)	$	(16.4)	$	(3.3)	$	(28.7)	$	(15.9)	$	(3.4)
Liabilities Incurred During the Year		(0.1)		-		(0.1)		-		-		-
Liabilities Settled During the Year		1.2		-		-		2.0		-		0.3
Accretion		(1.8)		(1.1)		(0.2)		(1.9)		(1.0)		(0.2)
Revisions in Estimated Cash Flows		-		(0.1)		-		-		0.5		-
Balance as of End of Year	$	(29.3)	$	(17.6)	$	(3.6)	$	(28.6)	$	(16.4)	$	(3.3)

7.

GOODWILL AND OTHER INTANGIBLE ASSETS (NU)

In accordance with GAAP, goodwill and intangible assets deemed to have indefinite useful lives are reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. However, if an event occurs or circumstances change that would indicate that goodwill might be impaired, NU management would test the goodwill between the annual testing dates. 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.

NU's reporting units are consistent with the operating segments underlying the reportable segments identified in Note 21, "Segment Information," to the consolidated financial statements. The only reporting unit that maintains goodwill is the Yankee Gas reporting unit, which is classified under the Regulated companies natural gas reportable segment and related to the acquisition of Yankee Energy System, Inc., parent of Yankee Gas. Such goodwill is not being recovered from the customers of Yankee Gas. The goodwill balance held by the Yankee Gas reporting unit as of December 31, 2010 and 2009 is $287.6 million.

NU completed its impairment analysis of the Yankee Gas goodwill balance as of October 1, 2010 and determined that no impairment exists. In completing this analysis, the fair value of the reporting unit was estimated using a discounted cash flow methodology and analyses of comparable companies and transactions.

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8.

SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by CL&P and WMECO is subject to periodic approval by the FERC and short-term borrowings in excess of 10 percent of net plant by PSNH are subject to approval by the NHPUC. As a result of the NHPUC having jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On December 22, 2009, the FERC granted authorization to allow CL&P and WMECO to incur total short-term borrowings up to a maximum of $450 million and $300 million, respectively, effective January 1, 2010 through December 31, 2011.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant. In an order dated December 17 2010, the NHPUC increased the amount of short-term borrowings authorized for PSNH to a maximum of 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2010, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled $224.4 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. In November 2003, CL&P obtained from its preferred stockholders a waiver of such 10 percent limit for a ten-year period expiring in March 2014, provided that all unsecured indebtedness does not exceed 20 percent of total capitalization. As of December 31, 2010, CL&P had approximately $909.6 million of unsecured debt capacity available under this authorization.

Yankee Gas is not required to obtain approval from any state or federal authority to incur short-term debt.

CL&P, PSNH, WMECO and Yankee Gas Credit Agreement: On September 24, 2010, CL&P, PSNH, WMECO and Yankee Gas jointly entered into a three-year unsecured revolving credit facility in the amount of $400 million, which expires on September 24, 2013. This facility replaced a five-year $400 million credit facility that was scheduled to expire on November 6, 2010. CL&P and PSNH may draw up to $300 million each under this facility, with WMECO and Yankee Gas able to draw up to $200 million each, 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 in short-term borrowings outstanding under this credit facility. The weighted average interest rate on such borrowings outstanding under this credit facility as of December 31, 2010 was 2.05 percent. There were no borrowings outstanding by CL&P, WMECO and Yankee Gas under this facility as of December 31, 2010. There were no borrowings outstanding under the previous facility as of

December 31, 2009.

NU Parent Credit Agreement: On September 24, 2010, NU parent entered into a three-year unsecured revolving credit facility in the amount of $500 million, which expires on September 24, 2013. This facility replaced a five-year $500 million credit facility that was scheduled to expire on November 6, 2010. Subject to the amount of advances outstanding, LOCs can be issued under this facility for periods up to 364 days in the name of NU parent or any of its subsidiaries up to the total amount of the facility. This total commitment may be increased to $600 million at the request of NU parent, subject to lender approval. Under this facility, NU parent can borrow either on a short-term or a long-term basis. As of December 31, 2010, NU parent had $237 million in short-term borrowings outstanding under this facility. The weighted-average interest rate on such borrowings outstanding under this credit facility as of December 31, 2010 was 2.85 percent. At December 31, 2009, NU had $100.3 million in short-term borrowings outstanding under the previous facility. The weighted-average interest rate on such borrowings outstanding as of December 31, 2009 was 0.63 percent. There were $32.1 million ($30.1 million for PSNH) in LOCs outstanding as of December 31, 2010. There were $41 million ($39 million for PSNH) in LOCs outstanding under the previous facility as of December 31, 2009.

Under these credit facilities, NU parent and CL&P, PSNH, WMECO and Yankee Gas may borrow at prime rates or LIBOR-based rates, plus an applicable margin based upon the higher of S&P's or Moody's credit ratings assigned to the borrower.

In addition, NU parent and CL&P, PSNH, WMECO and Yankee Gas must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. NU parent and CL&P, PSNH, WMECO and Yankee Gas were in compliance with these covenants as of December 31, 2010. If NU parent or CL&P, PSNH, WMECO or Yankee Gas were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid and additional borrowings by such borrower would not be permitted under the respective credit facility.

Amounts outstanding under these credit facilities are classified as current liabilities as Notes Payable to Banks on the accompanying consolidated balance sheets, as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at one time.

Pool: NU Parent, CL&P, PSNH, WMECO, Yankee Gas and certain of NU's other subsidiaries are members of the Pool. The Pool provides an efficient use of cash resources of NU and reduces outside short-term borrowings. NUSCO participates in the Pool and administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are met with available funds of other member companies, including funds borrowed by NU. NU may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on external loans of NU, however, bear interest at NU's cost and are payable on demand. In NU's consolidated financial statements, Pool amounts payable or receivable to or from members eliminate in consolidation. By order, the FERC has exempted all holding company system money pools from active regulation. As of December 31, 2010 and 2009, CL&P, PSNH and WMECO had the following borrowings from/(contributions to) the Pool with the respective weighted-average interest rate on borrowings from the Pool:

	As of and for the Years Ended December 31,					
	2010			2009		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Borrowings from/(Contributions to)	$ 6.2	$ 47.9	$ 20.4	$ (97.8)	$ 26.7	$ 136.1
Weighted-Average Interest Rates	0.19 %	0.18 %	0.14 %	0.22 %	0.15 %	0.15%

The net borrowings from/(contributions to) the Pool are recorded in Notes Payable to/Notes Receivable from Affiliated Companies, respectively.

9.

LONG-TERM DEBT

Long-term debt maturities and cash sinking fund requirements on debt outstanding as of December 31, 2010, for the years 2011 through 2015 and thereafter, which include fees and interest due for spent nuclear fuel disposal costs, net unamortized premiums or discounts and other fair value adjustments as of December 31, 2010, are as follows:

(Millions of Dollars)	**NU**
2011	$ 66.3
2012	267.3
2013	305.0
2014	275.0
2015	150.0
Thereafter	3,327.9
Fees and Interest due for Spent Nuclear Fuel Disposal Costs	301.0
Net Unamortized Premiums and Discounts and Other Fair Value Adjustments	6.7
Total	$ 4,699.2

Details of long-term debt outstanding for CL&P, PSNH and WMECO are as follows:

CL&P	**As of December 31,**	
(Millions of Dollars)	**2010**	**2009**
First Mortgage Bonds:		
7.875% 1994 Series D due 2024	$ 139.8	$ 139.8
4.800% 2004 Series A due 2014	150.0	150.0
5.750% 2004 Series B due 2034	130.0	130.0
5.000% 2005 Series A due 2015	100.0	100.0
5.625% 2005 Series B due 2035	100.0	100.0
6.350% 2006 Series A due 2036	250.0	250.0
5.375% 2007 Series A due 2017	150.0	150.0
5.750% 2007 Series B due 2037	150.0	150.0
5.750% 2007 Series C due 2017	100.0	100.0
6.375% 2007 Series D due 2037	100.0	100.0
5.650% 2008 Series A due 2018	300.0	300.0
5.500% 2009 Series A due 2019	250.0	250.0
Total First Mortgage Bonds	1,919.8	1,919.8
Pollution Control Notes:		
5.85%-5.90%, Fixed Rate, due 2016-2022	46.4	46.4
5.85%-5.95%, Fixed Rate Tax Exempt, due 2028	315.5	315.5
One-Year Fixed Rate Tax Exempt, due 2031 (1)	62.0	62.0
Total Pollution Control Notes	423.9	423.9
Total First Mortgage Bonds and Pollution Control Notes	2,343.7	2,343.7
Fees and Interest due for Spent Nuclear Fuel Disposal Costs	243.8	243.5
Less Amounts due Within One Year (1)	(62.0)	(62.0)
Unamortized Premiums and Discounts, Net	(4.4)	(4.8)
Long-Term Debt	$ 2,521.1	$ 2,520.4

(1)

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

PSNH	**As of December 31,**	
(Millions of Dollars)	**2010**	**2009**
First Mortgage Bonds:		
5.25% 2004 Series L, due 2014	$ 50.0	$ 50.0
5.60% 2005 Series M, due 2035	50.0	50.0
6.15% 2007 Series N, due 2017	70.0	70.0
6.00% 2008 Series O, due 2018	110.0	110.0
4.50% 2009 Series P, due 2019	150.0	150.0
Total First Mortgage Bonds	430.0	430.0
Pollution Control Revenue Bonds:		
6.00% Tax-Exempt, Series D, due 2021	75.0	75.0
6.00% Tax-Exempt, Series E, due 2021	44.8	44.8
Adjustable Rate, Series A, due 2021	89.3	89.3
4.75% Tax-Exempt, Series B, due 2021	89.3	89.3
5.45% Tax-Exempt, Series C, due 2021	108.9	108.9
Total Pollution Control Revenue Bonds	407.3	407.3
Unamortized Premiums and Discounts, Net	(0.9)	(1.0)
Long-Term Debt	$ 836.4	$ 836.3

WMECO	**As of December 31,**	
(Millions of Dollars)	**2010**	**2009**
Pollution Control Notes:		
Tax Exempt 1993 Series A, 5.85% due 2028	$ 53.8	$ 53.8
Other Notes:		
Senior Notes Series A, 5.00% due 2013	55.0	55.0
Senior Notes Series B, 5.90% due 2034	50.0	50.0
Senior Notes Series C, 5.24% due 2015	50.0	50.0
Senior Notes Series D, 6.70% due 2037	40.0	40.0
Senior Notes Series E, 5.10% due 2020	95.0	-
Total Pollution Control Notes and Other Notes	343.8	248.8
Fees and Interest due for Spent Nuclear Fuel Disposal Costs	57.2	57.1
Total Pollution Control Notes, Other Notes, and Fees and Interest for Spent Nuclear Fuel Disposal Costs	401.0	305.9
Unamortized Premiums and Discounts, Net	(0.7)	(0.4)
Long-Term Debt	$ 400.3	$ 305.5

Included in the NU amounts are $263 million of NU Parent Series A Senior Notes maturing in 2012 with a coupon rate of 7.25 percent and $250 million of NU Parent Series C Senior Notes maturing in 2013 with a coupon rate of 5.65 percent.

There are no cash sinking fund requirements or debt maturities for the years 2011 through 2013 for CL&P and PSNH; however, CL&P has $62 million of PCRBs that carry a coupon rate of 1.4 percent during the current one-year fixed-rate period and are subject to mandatory tender for purchase on April 1, 2011. There is a $263 million maturity in 2012 related to the NU parent Series A Senior notes. There are $55 million and $250 million of maturities in 2013 related to the WMECO Series A Senior Notes and the NU parent Series C Senior Notes, respectively. There are $150 million and $50 million of maturities in 2014 related to the CL&P 2004 Series A first mortgage bonds and the PSNH 2004 Series L first mortgage bonds, respectively. There are $100 million and $50 million of maturities in 2015 related to CL&P 2005 Series A first mortgage bonds and WMECO Series C Senior Notes, respectively. CL&P, PSNH and WMECO have $2.032 billion, $787.3 million and $238.8 million, respectively, of long-term debt maturities in the period from 2016 through 2037.

There are annual renewal and replacement fund requirements equal to 2.25 percent of the average of net depreciable utility property owned by PSNH in 1992, plus cumulative gross property additions thereafter. PSNH expects to meet these future fund requirements by certifying property additions. Any deficiency would need to be satisfied by the deposit of cash or bonds.

Essentially all utility plant of CL&P, PSNH and Yankee Gas is subject to the lien of each company's respective first mortgage bond indenture.

The CL&P, PSNH and WMECO tax-exempt bonds contain call provisions providing call prices ranging between 100 percent and 102 percent of par. All other securities are subject to make-whole provisions.

As of December 31, 2010, CL&P had $423.9 million of tax-exempt PCRBs, $315.5 million of which is secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indenture. CL&P has $62 million of tax-exempt PCRBs secured by first mortgage bonds.

As of December 31, 2010, PSNH had $407.3 million in outstanding PCRBs. PSNH's obligation to repay each series of PCRBs is secured by first mortgage bonds and three series, the 2001 Series A, B and C, also carry bond insurance. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. For financial reporting purposes, these first mortgage bonds would not be considered outstanding unless PSNH failed to meet its obligations under the PCRBs. The 2001 Series A PCRBs, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by the remarketing agent as a result of failed auctions due to general market concerns. The interest rate on this series of PCRBs has been reset by formula under the applicable documents every 35 days. The formula is based on a combination of the ratings on the PCRBs and an index rate. The interest rate has been between 0.16 percent and 4.03 percent since March 2008 and was 0.36 percent as of December 31, 2010. The Company is not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agent. The weighted average effective interest rate on PSNH's Series A variable-rate PCRBs was 0.34 percent in 2010 and 0.25 percent for 2009.

NU's, including CL&P, PSNH and WMECO, long-term debt agreements provide that NU and certain of its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to total capitalization ratio. NU and these subsidiaries are in compliance with these covenants as of December 31, 2010.

Yankee Gas has certain long-term debt agreements that contain cross-default provisions. These cross-default provisions apply to all of Yankee Gas outstanding first mortgage bond series. The cross-default provisions on Yankee Gas Series B Bonds would be triggered if Yankee Gas were to default in a payment due on indebtedness in excess of $2 million. The cross-default provisions on all other series of Yankee Gas first mortgage bonds would be triggered if Yankee Gas were to default in a payment due on indebtedness in excess of $10 million. PSNH would also be in default under its first mortgage indentures if it defaulted on any prior lien obligation exceeding $25 million. PSNH had no prior lien obligations as of December 31, 2010. There are no other debt issuances for CL&P, WMECO or NU parent with cross-default provisions as of December 31, 2010.

The accompanying consolidated statements of capitalization as of December 31, 2010 reflect the issuance in 2010 of bonds in the amount of $50 million at Yankee Gas, which are included in Long-Term Debt - First Mortgage Bonds and the issuance in 2010 of senior unsecured notes in the amount of $95 million at WMECO, which are included in Other Long-Term Debt.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 12B, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

The change in fair value totaling a positive $11.8 million and $13.3 million as of December 31, 2010 and 2009, respectively, on the accompanying consolidated statements of capitalization reflects the NU parent 7.25 percent amortizing note, due 2012 in the amount of $263 million, that is hedged with a fixed to floating interest rate swap. The change in fair value of the interest component of the debt was recorded as an adjustment to Long-Term Debt with an equal and offsetting adjustment to Derivative Assets for the change in fair value of the fixed to floating interest rate swap.

10.

EMPLOYEE BENEFITS

A.

Pension Benefits and Postretirement Benefits Other Than Pensions

Pursuant to GAAP, NU is required to record the funded status of its pension and PBOP plans on the accompanying consolidated balance sheets, based on the difference between the projected benefit obligation for the Pension Plan and accumulated postretirement benefit obligation for the PBOP Plan and the fair value of plan assets measured in accordance with fair value measurement accounting guidance. The funded status is recorded with an offset to Accumulated Other Comprehensive Income/(Loss) on the accompanying consolidated balance sheets. This amount is remeasured annually, or as circumstances dictate.

As of December 31, 2010 and 2009, NU recorded an after-tax charge totaling $0.5 million and $5.4 million, respectively, to Accumulated Other Comprehensive Income/(Loss) for its unregulated subsidiaries. Charges for the Regulated companies are recorded as Regulatory Assets and included as deferred benefit costs as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. For further information see Note 2, "Regulatory Accounting," to the consolidated financial statements. Regulatory accounting was also applied to the portions of the NUSCO costs that support the Regulated companies, as these amounts are also recoverable through rates charged to customers.

Pension Benefits: NUSCO sponsors a Pension Plan, which is subject to the provisions of ERISA. The Pension Plan covers nonbargaining unit employees (and bargaining unit employees, as negotiated) of NU, including CL&P, PSNH, and WMECO, hired before 2006 (or as negotiated, for bargaining unit employees). Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. NU allocates net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked by the trustee for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year. NU uses a December 31st measurement date for the Pension Plan. Pension expense/(income) affecting Net Income is as follows:

(Millions of Dollars)	For the Years Ended December 31,		
NU	**2010**	**2009**	**2008**
Total Pension Expense	$ 80.4	$ 39.7	$ 2.4
(Expense)/Income Capitalized as Utility Plant	(16.9)	(6.2)	4.9
Total Pension Expense, Net of Amounts Capitalized	$ 63.5	$ 33.5	$ 7.3
CL&P			
Total Pension Expense/(Income)	$ 8.5	$ (5.7)	$ (21.3)
(Expense)/Income Capitalized as Utility Plant	(3.8)	2.6	9.4
Total Pension Expense/(Income), Net of Amounts Capitalized	$ 4.7	$ (3.1)	$ (11.9)
PSNH			
Total Pension Expense	$ 28.1	$ 23.3	$ 18.1
Expense Capitalized as Utility Plant	(6.9)	(6.0)	(4.2)
Total Pension Expense, Net of Amounts Capitalized	$ 21.2	$ 17.3	$ 13.9
WMECO			
Total Pension Income	$ (0.1)	$ (2.9)	$ (6.1)
Income Capitalized as Utility Plant	-	1.2	2.1
Total Pension Income, Net of Amounts Capitalized	$ (0.1)	$ (1.7)	$ (4.0)

Actuarial Determination of Expense: Pension and PBOP expense consists of the service cost and prior service cost determined by actuaries, the interest cost based on the discounting of the obligations and the amortization of the net transition obligation, offset by the expected return on plan assets. Pension and PBOP expense also includes amortization of actuarial gains and losses, which represent differences between assumptions and actual or updated information.

The expected return on plan assets is calculated by applying the assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return based on the change in the fair value of assets during the year. As investment gains and losses are reflected in the average plan asset fair values, they are subject to amortization with other unrecognized gains/losses. Unrecognized gains/losses are amortized as a component of pension and PBOP expense over approximately 10 and 9 years, respectively, which is the average future service period of the employees.

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants, who are officers of NU, with benefits that would have been provided to them under the Pension Plan if certain Internal Revenue Code limitations were not imposed. NU allocates net periodic SERP benefit costs to its subsidiaries based upon actuarial calculations by participant.

Although the Company maintains a trust to support the SERP with marketable securities held in the NU supplemental benefit trust, the plan itself does not contain any assets. For information regarding the investments in the NU supplemental benefit trust that are used to support the SERP liability, see Note 5, "Marketable Securities," to the consolidated financial statements.

PBOP Plan: On behalf of NU's retirees, NUSCO also sponsors plans that provide certain retiree health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan. These benefits are available for employees retiring from NU who have met specified service requirements. For current employees and certain retirees, the total benefit is limited to two times the 1993 per retiree health care cost. These costs are charged to expense over the estimated work life of the employee. NU uses a December 31st measurement date for the PBOP Plan.

NU annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible.

NU allocates net periodic postretirement benefits expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year.

The following table represents information on NU's plan benefit obligations, fair values of plan assets, and funded status:

	As of December 31,					
	Pension Benefits		**SERP Benefits**		**PBOP Benefits**	
(Millions of Dollars)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Change in Benefit Obligation						
Benefit Obligation as of Beginning of Year	$ (2,571.0)	$ (2,297.7)	$ (39.3)	$ (34.2)	$ (475.7)	$ (436.0)
Service Cost	(50.3)	(45.0)	(0.7)	(0.8)	(8.5)	(7.2)
Interest Cost	(150.3)	(153.4)	(2.3)	(2.3)	(26.8)	(29.1)
Actuarial Loss	(139.3)	(203.8)	(1.3)	(4.3)	(17.5)	(44.5)
Federal Subsidy on Benefits Paid	-	-	-	-	(3.7)	(3.5)
Benefits Paid - Excluding Lump Sum Payments	130.2	128.9	2.5	2.3	42.3	44.6
Benefits Paid - Lump Sum Payments	0.9	-	-	-	-	-
Benefit Obligation as of End of Year	$ (2,779.8)	$ (2,571.0)	$ (41.1)	$ (39.3)	$ (489.9)	$ (475.7)
Change in Plan Assets						
Fair Value of Plan Assets as of Beginning of Year	$ 1,789.6	$ 1,556.8	N/A	N/A	$ 240.3	$ 195.6
Actual Return on Plan Assets	274.1	361.7	N/A	N/A	34.9	48.5
Employer Contribution	45.0	-	N/A	N/A	45.6	40.8
Benefits Paid - Excluding Lump Sum Payments	(130.2)	(128.9)	N/A	N/A	(42.3)	(44.6)
Benefits Paid - Lump Sum Payments	(0.9)	-	N/A	N/A	-	-
Fair Value of Plan Assets as of End of Year	$ 1,977.6	$ 1,789.6	N/A	N/A	$ 278.5	$ 240.3
Funded Status as of December 31st	$ (802.2)	$ (781.4)	$ (41.1)	$ (39.3)	$ (211.4)	$ (235.4)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above as of December 31, 2010 and 2009 are as follows:

	As of December 31,					
(Millions of Dollars)	**Pension Benefits**		**SERP Benefits**		**PBOP Benefits**	
NU	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Accrued Pension	$ (802.2)	$ (781.4)	$ -	$ -	$ -	$ -

Other Current Liabilities		-		-		(4.1)		(2.9)		-		-
Other Long-Term Liabilities		-		-		(37.0)		(36.4)		(211.4)		(235.4)
CL&P												
Accrued Pension	$	(42.5)	$	(51.3)	$	-	$	-	$	-	$	-
Other Current Liabilities		-		-		(0.4)		(0.3)		-		-
Other Long-Term Liabilities		-		-		(3.0)		(3.1)		(81.6)		(94.9)
PSNH												
Accrued Pension	$	(261.1)	$	(272.9)	$	-	$	-	$	-	$	-
Other Current Liabilities		-		-		(0.3)		(0.1)		-		-
Other Long-Term Liabilities		-		-		(1.9)		(2.0)		(33.0)		(39.7)
WMECO												
Prepaid Pension	$	13.6	$	6.9	$	-	$	-	$	-	$	-
Other Long-Term Liabilities		-		-		(0.4)		(0.4)		(15.0)		(17.4)

The accumulated benefit obligation for the Pension Plan and SERP as of December 31, 2010 and 2009 is as follows:

	Pension Benefits				**SERP Benefits**			
(Millions of Dollars)		**2010**		**2009**		**2010**		**2009**
NU	$	2,512.2	$	2,034.7	$	38.9	$	36.9
CL&P		864.9		725.8		3.4		3.3
PSNH		395.8		312.4		2.1		1.9
WMECO		177.0		146.4		0.4		0.3

The Company amortizes the prior service cost on an individual subsidiary basis and unrecognized net actuarial gains/(losses) and any remaining transition obligation over the remaining service lives of its employees as calculated on an NU consolidated basis. The pension transition obligation is fully amortized and the PBOP transition obligation will be fully amortized in 2013.

The following is a summary of amounts recorded as Regulatory Assets as of December 31, 2010 and 2009 and the changes in those amounts recorded during the years:

NU	As of December 31, **Pension**		**SERP**		**PBOP**	
(Millions of Dollars)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Net Actuarial Losses as of Beginning of Year	$ 869.4	$ 867.2	$ 7.5	$ 3.2	$ 175.9	$ 170.0
Amounts Reclassified as Net Periodic Benefit Expense	(49.9)	(20.4)	(1.1)	(0.4)	(15.9)	(10.0)
Actuarial Losses Arising During the Year	44.0	22.6	1.3	4.7	4.2	15.9
Actuarial Losses as of End of Year	$ 863.5	$ 869.4	$ 7.7	$ 7.5	$ 164.2	$ 175.9
Prior Service Cost/(Credit) as of Beginning of Year	$ 48.1	$ 57.8	$ 0.2	$ 0.4	$ (3.0)	$ (3.3)
Amounts Reclassified as Net Periodic Benefit (Expense)/Income	(9.5)	(9.5)	-	(0.2)	0.3	0.3
Prior Service Credit Arising During the Year	-	(0.2)	-	-	-	-
Prior Service Cost/(Credit) as of End of Year	$ 38.6	$ 48.1	$ 0.2	$ 0.2	$ (2.7)	$ (3.0)
Transition Obligation as of Beginning of Year	$ -	$ 0.3	$ -	$ -	$ 34.0	$ 45.3
Amounts Reclassified as Net Periodic Benefit Expense	-	(0.3)	-	-	(11.3)	(11.3)
Transition Obligation as of End of Year	$ -	$ -	$ -	$ -	$ 22.7	$ 34.0
Total Deferred Benefit Costs Recorded as Regulatory Assets	$ 902.1	$ 917.5	$ 7.9	$ 7.7	$ 184.2	$ 206.9

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2011 are as follows:

NU	Estimated Expense in 2011 **Pension**	**SERP**	**PBOP**
(Millions of Dollars)			
Net Actuarial Loss	$ 78.3	$ 1.1	$ 17.3
Prior Service Credit	9.5	-	(0.3)
Transition Obligation	-	-	11.3
Total	$ 87.8	$ 1.1	$ 28.3

The following is a summary of amounts recorded in Accumulated Other Comprehensive Loss as of December 31, 2010 and 2009 and the changes in those amounts recorded to Other Comprehensive Income/(Loss):

	As of December 31,					
NU	**Pension**		**SERP**		**PBOP**	
(Millions of Dollars)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Net Actuarial Losses/(Gains) as of Beginning of Year	$ 51.1	$ 42.4	$ (0.2)	$ 0.1	$ 9.1	$ 8.8
Amounts Reclassified as Net Periodic Benefit Expense	(2.7)	(0.1)	-	-	(0.8)	(0.5)
Actuarial Losses/(Gains) Arising During the Year	3.6	8.8	0.1	(0.3)	0.7	0.8
Actuarial Losses/(Gains) as of End of Year	$ 52.0	$ 51.1	$ (0.1)	$ (0.2)	$ 9.0	$ 9.1
Prior Service Cost as of Beginning of Year	$ 2.0	$ 2.1	$ -	$ -	$ -	$ -
Amounts Reclassified as Net Periodic Benefit Expense	(0.3)	(0.3)	-	-	-	-
Prior Service Cost Arising During the Year	-	0.2	-	-	-	-
Prior Service Cost as of End of Year	$ 1.7	$ 2.0	$ -	$ -	$ -	$ -
Transition Obligation as of Beginning of Year	$ -	$ -	$ -	$ -	$ 0.7	$ 0.9
Amounts Reclassified as Net Periodic Benefit Expense	-	-	-	-	(0.2)	(0.2)
Transition Obligation as of End of Year	$ -	$ -	$ -	$ -	$ 0.5	$ 0.7
Total Pension, SERP and PBOP in Accumulated Other Comprehensive Loss	$ 53.7	$ 53.1	$ (0.1)	$ (0.2)	$ 9.5	$ 9.8

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2011 are as follows:

NU	**Estimated Expense in 2011**		
(Millions of Dollars)	**Pension**	**SERP**	**PBOP**
Net Actuarial Loss	$ 4.6	$ -	$ 0.9
Prior Service Cost	0.3	-	-
Transition Obligation	-	-	0.2
Total	$ 4.9	$ -	$ 1.1

For further information, see Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

The following actuarial assumptions were used in calculating the plans' year end funded status:

	As of December 31,			
	Pension Benefits and SERP		PBOP Benefits	
Balance Sheets	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.57%	5.98%	5.28%	5.73%
Compensation/Progression Rate	3.50%	4.00%	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	7.00%	7.50%

The components of net periodic benefit expense/(income) are as follows:

	For the Years Ended December 31,								
NU	**Pension Benefits**			**SERP Benefits**			**PBOP Benefits**		
(Millions of Dollars)	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Service Cost	$ 50.3	$ 45.0	$ 43.9	$ 0.7	$ 0.8	$ 0.7	$ 8.5	$ 7.2	$ 7.1
Interest Cost	150.3	153.4	144.0	2.3	2.3	2.0	26.8	29.1	28.3
Expected Return on Plan Assets	(182.6)	(189.4)	(200.2)	-	-	-	(21.7)	(20.9)	(21.1)
Net Transition Obligation Cost	-	0.3	0.2	-	-	-	11.6	11.6	11.6
Prior Service Cost/(Credit)	9.8	9.8	9.9	0.1	0.1	0.1	(0.3)	(0.3)	(0.3)
Actuarial Loss	52.6	20.6	4.6	1.0	0.4	0.3	16.7	10.5	10.6
Total - Net Periodic Expense	$ 80.4	$ 39.7	$ 2.4	$ 4.1	$ 3.6	$ 3.1	$ 41.6	$ 37.2	$ 36.2

	For the Years Ended December 31,								
CL&P	**Pension Benefits**			**SERP Benefits**			**PBOP Benefits**		
(Millions of Dollars)	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Service Cost	$ 17.6	$ 16.0	$ 15.4	$ -	$ -	$ -	$ 2.7	$ 2.2	$ 2.2
Interest Cost	52.0	54.3	51.4	0.2	0.2	0.2	10.5	11.5	11.3
Expected Return on Plan Assets	(85.8)	(89.0)	(93.4)	-	-	-	(8.7)	(8.3)	(8.4)
Net Transition Obligation Cost	-	-	-	-	-	-	6.1	6.1	6.1
Prior Service Cost	4.2	4.2	4.2	-	-	-	-	-	-
Actuarial Loss	20.5	8.8	1.1	0.2	0.1	0.1	6.3	4.0	4.5
Total - Net Periodic Expense/(Income)	$ 8.5	$ (5.7)	$ (21.3)	$ 0.4	$ 0.3	$ 0.3	$ 16.9	$ 15.5	$ 15.7

	For the Years Ended December 31,								
PSNH	**Pension Benefits**			**SERP Benefits**			**PBOP Benefits**		
(Millions of Dollars)	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Service Cost	$ 9.9	$ 8.8	$ 9.2	$ 0.1	$ 0.1	$ -	$ 1.8	$ 1.5	$ 1.7
Interest Cost	24.0	24.3	23.2	0.1	0.1	0.1	5.0	5.4	5.2
Expected Return on Plan Assets	(14.7)	(15.0)	(17.9)	-	-	-	(4.3)	(4.1)	(4.0)
Net Transition Obligation Cost	-	0.3	0.3	-	-	-	2.5	2.5	2.5
Prior Service Cost	1.8	1.8	1.9	-	-	-	-	-	-
Actuarial Loss	7.1	3.1	1.4	0.1	0.1	0.1	2.7	1.7	1.7
Total - Net Periodic Expense	$ 28.1	$ 23.3	$ 18.1	$ 0.3	$ 0.3	$ 0.2	$ 7.7	$ 7.0	$ 7.1

	For the Years Ended December 31,								
WMECO	**Pension Benefits**			**SERP Benefits**			**PBOP Benefits**		
(Millions of Dollars)	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Service Cost	$ 3.5	$ 3.3	$ 3.2	$ -	$ -	$ -	$ 0.6	$ 0.5	$ 0.5
Interest Cost	10.7	11.1	10.4	-	-	0.1	2.3	2.5	2.4
Expected Return on Plan Assets	(19.5)	(20.0)	(20.7)	-	-	-	(2.1)	(2.0)	(2.1)
Net Transition Obligation Cost	-	-	-	-	-	-	1.3	1.3	1.4
Prior Service Cost	0.9	0.9	0.9	-	-	-	-	-	-
Actuarial Loss	4.3	1.8	0.1	-	-	-	0.9	0.4	0.6
Total - Net Periodic Expense/(Income)	$ (0.1)	$ (2.9)	$ (6.1)	$ -	$ -	$ 0.1	$ 3.0	$ 2.7	$ 2.8

Not included in the Pension Plan, PBOP Plan and SERP amounts above for CL&P, PSNH and WMECO are related intercompany allocations as follows:

	For the Years Ended December 31,								
	CL&P			**PSNH**			**WMECO**		
(Millions of Dollars)	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Pension Benefits	$ 23.2	$ 14.5	$ 8.9	$ 5.4	$ 3.1	$ 2.0	$ 4.2	$ 2.4	$ 1.5
PBOP Benefits	7.9	7.3	6.7	2.0	1.7	1.5	1.4	1.1	1.1
SERP Benefits	2.0	1.8	1.6	0.6	0.5	0.4	0.3	0.3	0.2

The following assumptions were used to calculate pension and PBOP expense and income amounts:

	For the Years Ended December 31,					
	Pension Benefits and SERP			PBOP Benefits		
Statements of Income	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.98%	6.89%	6.60 %	5.73%	6.90 %	6.35 %
Expected Long-Term Rate of Return	8.75%	8.75%	8.75 %	N/A	N/A	N/A
Compensation/Progression Rate	4.00%	4.00%	4.00 %	N/A	N/A	N/A
Expected Long-Term Rate of Return -						
Health Assets, Taxable	N/A	N/A	N/A	6.85%	6.85 %	6.85 %
Life Assets and Non-Taxable Health Assets	N/A	N/A	N/A	8.75%	8.75 %	8.75 %

For 2011 through 2013, the health care trend cost assumption is 7 percent, subsequently decreasing one half percentage point per year to an ultimate rate of 5 percent in 2017. For the year ended December 31, 2010, the assumed healthcare trend was 7.5 percent, decreasing by 5 percent and reaching the ultimate trend rate of 5 percent in 2015.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point for the year ended December 31, 2010 would have the following effects:

(Millions of Dollars) **NU**	**One Percentage Point Increase**	**One Percentage Point Decrease**
Effect on Postretirement Benefit Obligation	$ 14.5	$ (12.1)
Effect on Total Service and Interest Cost Components	1.2	(0.9)

Fair Value of Pension and PBOP Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and PBOP payments. NU's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment strategy for each asset category includes a diversification of asset types, fund strategy and fund managers and establishes target asset allocations that are routinely reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, NU evaluated input from actuaries and consultants, as well as long-term inflation assumptions and historical returns. For 2010, management has assumed long-term rates of return of 8.25

percent on Pension Plan assets and PBOP Plan life and nontaxable health assets and 6.45 percent for PBOP taxable health assets. These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31,							
	Pension and PBOP Life and Non-Taxable Health 2010		PBOP (Taxable Health) 2010		Pension 2009		PBOP (Health and Life) 2009	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:								
United States	24%	9%	55%	9%	24%	9.25%	55%	9.25%
International	13%	9%	15%	9%	13%	9.25%	11%	9.25%
Emerging Markets	3%	10%	-	-	3%	10.25%	2%	10.25%
Private Equity	12%	13%	-	-	12%	14.25%	-	-
Debt Securities:								
Fixed Income	20%	5%	30%	5%	20%	5.7%	27%	5.7%
High Yield Fixed Income	3.5%	7.5%	-	-	3.5%	7.7%	5%	7.7%
Emerging Markets Debt	3.5%	7.5%	-	-	3.5%	7.7%	-	-
Real Estate And Other Assets	8%	7.5%	-	-	8%	7.5%	-	-
Hedge Funds	13%	7%	-	-	13%	8%	-	-

The following table presents, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	Pension Plan Fair Value Measurements as of December 31,							
(Millions of Dollars)	2010				2009			
Asset Category:	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Equity Securities:								
United States (1)	$ 256.3	$ 46.9	$ 266.0	$ 569.2	$ 135.2	$ 150.1	$ 252.1	$ 537.4
International (2)	6.4	250.9	-	257.3	7.1	217.3	-	224.4
Emerging Markets (2)	-	81.1	-	81.1	-	67.1	-	67.1
Private Equity (5)	6.9	-	229.5	236.4	21.9	-	193.8	215.7
Fixed Income (3)	7.6	261.6	247.6	516.8	49.4	251.9	174.0	475.3
Real Estate and Other Assets (6)	-	26.0	43.7	69.7	-	-	38.5	38.5
Hedge Funds	-	-	247.1	247.1	-	-	231.2	231.2
Total	$ 277.2	$ 666.5	$ 1,033.9	$ 1,977.6	$ 213.6	$ 686.4	$ 889.6	$ 1,789.6

	PBOP Plan Fair Value Measurements as of December 31,							
(Millions of Dollars)	2010				2009			
Asset Category:	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and Cash Equivalents	$ 4.4	$ -	$ -	$ 4.4	$ 4.2	$ -	$ -	$ 4.2
Equity Securities:								
United States	132.1	-	10.1	142.2	140.3	-	-	140.3
International	34.8	-	-	34.8	28.0	-	-	28.0
Emerging Markets	7.7	-	-	7.7	-	-	-	-
Debt Securities:								
Fixed Income (4)	-	35.3	23.4	58.7	-	36.9	24.6	61.5
High Yield Fixed Income	-	4.4	-	4.4	6.3	-	-	6.3
	-	4.8	-	4.8	-	-	-	-

Emerging Market Debt																
Hedge Funds		-		-		16.4		16.4		-		-		-		-
Private Equity		-		-		0.3		0.3		-		-		-		-
Real Estate and Other Assets		-		4.8		-		4.8		-		-		-		-
Total	$	179.0	$	49.3	$	50.2	$	278.5	$	178.8	$	36.9	$	24.6	$	240.3

(1)

United States Equities classified as Level 2 include investments in commingled funds totaling $34.8 million and $77.1 million and unrealized gains on holdings in equity index swaps totaling $12.1 million and $73 million for the years ended December 31, 2010 and 2009, respectively. Level 3 investments include hedge funds that are overlayed with equity index swaps and futures contracts. Level 1 investments represent primarily equity holdings and also includes unrealized gains and losses on equity index futures contracts.

(2)

The International and Emerging Markets Equities categorized as Level 2 represent investments in commingled funds.

(3)

Fixed Income securities classified as Level 2 include investments in debt securities, including high yield bond funds, U.S. government issued securities, corporate bonds, asset backed securities and insurance contracts totaling $261.6 million and $201.2 million for the years ended December 31, 2010 and 2009, respectively. In 2009, this amount above included unrealized gains on fixed income swaps of $50.7 million. Level 3 investments include fixed income funds totaling $147.1 million and $80.5 million that invest in senior credit distressed credit funds, and hedge funds totaling $100.5 million and $93.5 million that are overlayed with interest rate swaps and fixed income index swaps for the years ended December 31, 2010 and 2009, respectively. Level 1 investments include exchange traded funds and in 2009 also included unrealized gains on fixed income index futures contracts totaling $29.8 million.

(4)

Fixed Income investments classified as Level 2 include U.S. government issued securities, municipal bonds, corporate bonds and other debt securities. The amount classified in Level 3 represents funds that invests in senior credit distressed income securities totaling $7.6 million and $6.4 million and hedge funds totaling $15.8 million and $18.2 million for the years ended December 31, 2010 and 2009, respectively.

(5)

Private Equity amounts classified as Level 1 represent unrealized gains on futures contracts.

(6)

Level 2 investments relate to other assets not invested in real estate.

The Company values assets based on observable inputs when available. Equity securities and futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date. Commingled funds included in Level 2 equity securities are recorded at the net asset value provided by the asset manager, which is based on the market prices of the underlying equity securities. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows. Fixed income securities included in Level 2 are valued using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures. Hedge funds and investments in distressed credit funds are recorded at net asset value based on the values of the underlying assets. The assets in the hedge funds and distressed credit income funds are valued using observable inputs and are classified as Level 3 within the fair value hierarchy due to redemption restrictions. Private Equity investments and Real Estate and Other Assets are valued using the net asset value provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or market approaches to the valuation of the underlying investments. These investments are classified as Level 3 due to redemption restrictions.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3): The following tables present changes for the Level 3 category of Pension and PBOP Plan assets:

	Pension Plan As of December 31, 2010					
(Millions of Dollars)	**United States Equity**	**Private Equity**	**Fixed Income**	**Real Estate and Other Assets**	**Hedge Funds**	**Total**
Balance as of January 1, 2010	$ 252.1	$ 193.8	$ 174.0	$ 38.5	$ 231.2	$ 889.6
Actual Return on Plan Assets:						
Relating to Assets Still Held as of Year End	13.9	10.9	21.0	0.5	15.9	62.2
Relating to Assets Distributed During the Year	-	-	-	0.5	-	0.5
Purchases, Sales and Settlements	-	24.8	52.6	4.2	-	81.6
Balance as of December 31, 2010	$ 266.0	$ 229.5	$ 247.6	$ 43.7	$ 247.1	$ 1,033.9

	Pension Plan As of December 31, 2009					
(Millions of Dollars)	**United States Equity**	**Private Equity**	**Fixed Income**	**Real Estate and Other Assets**	**Hedge Funds**	**Total**
Balance as of January 1, 2009	$ 333.3	$ 175.2	$ 227.5	$ 58.2	$ -	$ 794.2
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held as of Year End	68.8	11.0	49.8	(26.1)	6.2	109.7
Relating to Assets Distributed During the Year	-	(3.9)	-	-	-	(3.9)

Purchases, Sales and Settlements	(15.0)	11.5	(13.3)	6.4	-	(10.4)
Transfer Between Asset Categories	(135.0)	-	(90.0)	-	225.0	-
Balance as of December 31, 2009	$ 252.1	$ 193.8	$ 174.0	$ 38.5	$ 231.2	$ 889.6

	PBOP Plan As of December 31, 2010					2009
(Millions of Dollars)	**United States Equity**	**Private Equity**	**Fixed Income**	**Hedge Funds**	**Total**	**Fixed Income**
Balance as of Beginning of Year	$ -	$ -	$ 24.6	$ -	$ 24.6	$ 18.9
Actual Return/(Loss) on Plan Assets:						
Relating to Assets Still Held at Year End	0.5	-	3.2	0.4	4.1	-
Relating to Assets Sold During the Year	-	-	-	-	-	4.5
Purchases, Sales and Settlements	9.6	0.3	(4.4)	16.0	21.5	1.2
Balance as of End of Year	$ 10.1	$ 0.3	$ 23.4	$ 16.4	$ 50.2	$ 24.6

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid/(received) for the Pension, SERP and PBOP Plans:

NU *(Millions of Dollars)*	**Pension Benefits**	**SERP Benefits**	**PBOP Benefits**	**Government Benefits**
2011	$ 132.9	$ 2.9	$ 40.8	$ (4.1)
2012	137.8	3.2	41.3	(4.4)
2013	143.4	3.3	41.8	(4.8)
2014	149.7	3.4	42.3	(5.1)
2015	155.7	3.4	42.7	(5.5)
2016-2020	886.8	18.6	216.4	(31.8)

The government benefits represent amounts expected to be received from the federal government for the Medicare prescription drug benefit under the PBOP Plan related to the corresponding year's benefit payments.

Contributions: Currently, NU's policy is to annually fund the Pension Plan in an amount at least equal to an amount that will satisfy the requirements of ERISA and the Internal Revenue Code. Due to the underfunded balance as of January 1, 2009, PSNH made a contribution of $45 million to the plan in the third quarter of 2010. Due to the underfunded balance as of January 1, 2010, NU is required to make an additional contribution to the Pension Plan of approximately $145 million in 2011, which will be made in quarterly installments, to meet current minimum funding requirements.

For the PBOP Plan, it is currently NU's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. NU contributed $41.8 million for the year ended December 31, 2010 to fund the PBOP Plan and expects to make $42.8 million in contributions to the PBOP Plan in 2011. NU makes an additional contribution to the PBOP

Plan for the amounts received from the federal Medicare subsidy. This amount was $3.8 million in 2010 and is estimated to be $4.1 million in 2011.

B.

Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all NU employees, including CL&P, PSNH and WMECO employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares allocated from the ESOP. The 401(k) matching contributions of cash and NU common shares made by NU were $12.7 million ($4 million for CL&P, $2.4 million for PSNH and $0.8 million for WMECO) in 2010, $12.2 million ($3.9 million for CL&P, $2.3 million for PSNH and $0.7 million for WMECO) in 2009, and $12 million ($4 million for CL&P, $2.3 million for PSNH and $0.7 million for WMECO) in 2008.

Effective on January 1, 2006, all newly hired, non-bargaining unit employees, and effective on January 1, 2007 or as subject to collective bargaining agreements, certain newly hired bargaining unit employees participate in a new program under the 401(k) Savings Plan called the K-Vantage benefit. These employees are not eligible to participate in the Pension Plan. In addition, participants in the Pension Plan as of January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU were $3.4 million ($0.4 million for CL&P, $0.4 million for PSNH and $0.1 million for WMECO) in 2010, $2.6 million (de minimis amounts for CL&P and WMECO and $0.3 million for PSNH) in 2009, and $2 million (de minimis amounts for CL&P and WMECO and $0.3 million for PSNH) in 2008.

C.

Employee Stock Ownership Plan

NU maintains an ESOP for purposes of allocating shares to NU, CL&P, PSNH, and WMECO's employees participating in NU's 401(k) Savings Plan. NU issued unsecured notes during 1991 and 1992 totaling $250 million, the proceeds of which were loaned to the ESOP trust (ESOP Notes) for the purchase of 10.8 million newly issued NU common shares (ESOP shares). The ESOP trust was obligated to make principal and interest payments to NU on the ESOP Notes at the same rate that ESOP shares were allocated to employee accounts in the 401(k) Savings Plan. Under this arrangement, NU made annual contributions to the ESOP trust equal to the ESOP's debt service, less dividends received by the ESOP. NU's contributions to the ESOP trust for the years ended December 31, 2010, 2009 and 2008 totaled $1.1 million, $6.1 million and $6 million, respectively. During 2010, the ESOP Notes were fully repaid and all ESOP shares purchased with the proceeds of the ESOP Notes were fully allocated. Following complete allocation of the ESOP shares in 2010, continuing allocations of NU common shares were made from NU treasury shares to satisfy the 401(k) Savings Plan obligation to provide a portion of the matching contribution in NU common shares.

For treasury shares used to satisfy the 401(k) Savings Plan matching contributions, compensation expense is recognized equal to the fair value of shares that have been allocated to participants. Any difference between the fair value and the average cost of the allocated treasury shares is charged or credited to Capital Surplus, Paid In. For the years ended December 31, 2010, 2009 and 2008, NU recognized $8.5 million, $8.2 million and $8 million, respectively, of expense related to the ESOP.

Dividends on the ESOP unallocated shares are not considered dividends for financial reporting purposes. During the first and second quarters of 2008, NU paid a $0.20 per share quarterly dividend. During the third and fourth quarters of 2008, NU paid a $0.2125 per share quarterly dividend. NU paid a $0.2375 per share quarterly dividend in 2009 and a $0.25625 per share quarterly dividend in 2010.

In 2010 and 2009, the ESOP trust allocated 127,054 and 542,724 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. As of December 31, 2010, total allocated ESOP shares were 10,800,185 and there were no unallocated ESOP shares remaining. As of December 31, 2009, total allocated ESOP shares were 10,673,131 and total unallocated ESOP shares were 127,054. The fair market value of the unallocated ESOP shares as of December 31, 2009 was $3.3 million.

D.

Share-Based Payments

NU maintains an ESPP and other long-term equity-based incentive plans under the NU Incentive Plan in which NU, CL&P, PSNH, and WMECO employees and officers are entitled to participate. NU, CL&P, PSNH, and WMECO record compensation cost related to these plans, as applicable, for shares issued or sold to NU, CL&P, PSNH, and WMECO employees and officers, as well as the allocation of costs associated with shares issued or sold to NUSCO employees and officers that support CL&P, PSNH, and WMECO.

In accordance with accounting guidance for share-based payments, share-based compensation awards are recorded using the fair value-based method based on the fair value at the date of grant. This guidance applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed.

NU accounts for its various share-based plans as follows:

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For grants of restricted shares and RSUs, NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the vesting period based upon the fair value of NU's common shares at the date of grant. Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.

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For grants of performance shares, NU records compensation expense, net of estimated forfeitures, on a straight-line basis over the vesting period. Performance shares vest based upon the achievement of Company targets. For the majority of performance shares, fair value is based upon the value of NU's common shares at the date of grant and compensation expense is recorded based upon the probable outcome of the achievement of Company targets. The remaining performance shares are based upon the achievement of the Company's share price as compared to an index of similar equity securities. The fair value at the date of grant for these remaining performance shares was determined using a lattice model and compensation expense is recorded over the vesting period.

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NU has not granted any stock options since 2002, and no compensation expense has been recorded. All options were fully vested prior to January 1, 2006.

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For shares sold under the ESPP, no compensation expense is recorded, as the ESPP qualifies as a non-compensatory plan under relevant accounting guidance.

For the years ended December 31, 2010, 2009 and 2008, tax expense in excess of compensation expense totaling $0.9 million, $0.9 million and $1.6 million, respectively, increased cash flows from financing activities.

NU Incentive Plan: Under the NU Incentive Plan, in which CL&P, PSNH and WMECO participate, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance shares and stock options to eligible employees and board members. As of December 31, 2010 and 2009, NU had 3,068,850 and 2,363,521 common shares, respectively, available for issuance under the NU Incentive Plan.

Restricted Shares: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. The remaining restricted shares under these programs were fully vested as of December 31, 2008 and the total compensation cost recorded had a de minimis impact to NU, CL&P, PSNH and WMECO for the year ended December 31, 2008.

RSUs: NU has granted RSUs under the 2004 through 2010 incentive programs that are subject to three-year and four-year graded vesting schedules for employees, and one-year graded vesting schedules for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of RSU transactions is as follows:

RSUs

	RSUs (Units)	Weighted Average Grant-Date Fair Value	Total Grant-Date Fair Value (Millions)
Outstanding as of December 31, 2007	831,000	$ 22.99	$ 19.1
Granted	352,482	$ 26.82	$ 9.5
Shares issued	(263,422)	$ 21.94	$ 5.8
Forfeited	(7,069)	$ 25.97	$ 0.2
Outstanding as of December 31, 2008	912,991	$ 24.75	$ 22.6
Granted	347,112	$ 23.26	$ 8.1
Shares issued	(203,888)	$ 25.55	$ 5.2
Forfeited	(18,303)	$ 26.26	$ 0.5
Outstanding as of December 31, 2009	1,037,912	$ 24.07	$ 25.0
Granted	258,174	$ 26.03	$ 6.7
Shares issued	(267,951)	$ 25.05	$ 6.7
Forfeited	(13,656)	$ 24.26	$ 0.3
Outstanding as of December 31, 2010	1,014,479	$ 24.31	$ 24.7

As of December 31, 2010 and 2009, the number and weighted average grant-date fair value of RSUs not vested was 519,900 and $12.9 million, and 571,673 and $15.2 million, respectively. The number and weighted average grant-date fair value of RSUs vested during 2010 was 317,866 and $8.3 million, respectively. As of December 31, 2010, 494,579 RSUs were fully vested and 493,905 are expected to vest.

On November 16, 2010, NU granted 192,309 RSUs to certain executives, contingent upon completion of the proposed merger with NSTAR, with a three year vesting period that would begin as of the date of completion of the merger.

Performance Shares: NU has granted performance shares under the 2009 and 2010 incentive programs that vest based upon the achievement of Company targets at the end of a three-year performance measurement period. Performance shares are paid in shares, subsequent to the performance measurement period. A summary of performance share transactions as follows:

Performance Shares	**Performance Shares (Units)**	**Weighted Average Grant-Date Fair Value**	**Total Grant-Date Fair Value (Millions)**
Outstanding as of December 31, 2008	-	$ -	$ -
Granted	104,150	$ 23.93	$ 2.5
Shares issued	-	$ -	$ -
Forfeited	(5,064)	$ 23.96	$ 0.1
Outstanding as of December 31, 2009	99,086	$ 23.93	$ 2.4
Granted	149,520	$ 25.24	$ 3.8
Shares issued	-	$ -	$ -
Forfeited	(47)	$ 23.96	$ -
Outstanding as of December 31, 2010	248,559	$ 24.72	$ 6.1

As of December 31, 2010, 120 percent of performance shares are expected to vest under the 2009 incentive program and 106 percent are expected to vest under the 2010 incentive program, based upon the probable outcome of certain performance metrics.

The total compensation cost recognized by NU (by CL&P, PSNH and WMECO) for share-based compensation awards was $10.5 million ($6.2 million, $2.1 million and $1.1 million), $8.8 million ($5.3 million, $1.7 million and $0.9 million) and $6.5 million ($4 million, $1.2 million and $0.7 million) for the years ended December 31, 2010, 2009 and 2008, respectively. The associated future income tax benefit recognized was $4.2 million ($2.5 million, $0.9 million and $0.4 million), $3.5 million ($2.1 million, $0.7 million and $0.4 million) and $2.6 million ($1.6 million, $0.5 million and $0.3 million) for the years ended December 31, 2010, 2009 and 2008, respectively.

As of December 31, 2010, there was $7.6 million of total unrecognized compensation cost related to nonvested share-based awards for NU, $4.5 million for CL&P, $1.4 million for PSNH and $0.9 million for WMECO. This cost is expected to be recognized ratably over a weighted-average period of 1.75 years for NU, 1.76 years for CL&P, 1.69 years for PSNH and 1.75 years for WMECO.

Stock Options: Prior to 2003, NU granted stock options to certain employees. The options expire ten years from the date of grant. These options were fully vested as of December 31, 2005. The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding as of December 31, 2010 is 1.0 years. A summary of stock option transactions is as follows:

		Exercise Price Per Share			
	Options	**Range**		**Weighted Average**	**Intrinsic Value (Millions)**
Outstanding and exercisable - December 31, 2007	397,180	$ 14.9375	- $ 21.0300	$ 18.3369	
Exercised	(76,260)			$ 16.2473	$ 0.6
Forfeited and cancelled	-			$ -	
Outstanding and exercisable - December 31, 2008	320,920	$ 14.9375	- $ 21.0300	$ 18.8335	
Exercised	(95,704)			$ 18.5418	$ 0.6
Forfeited and cancelled	-			$ -	
Outstanding and exercisable - December 31, 2009	225,216	$ 17.4000	- $ 21.0300	$ 18.9574	
Exercised	(112,617)			$	$

				$ 19.1196	1.0
Forfeited and cancelled	-			-	
Outstanding and exercisable - December 31, 2010	112,599	$17.4000	-$21.0300	$ 18.7952	$ 1.5

Cash received for options exercised during the year ended December 31, 2010 totaled $2.2 million. The tax benefit realized from stock options exercised totaled $0.4 million for the year ended December 31, 2010.

Employee Share Purchase Plan: NU maintains an ESPP for all eligible NU, CL&P, PSNH, and WMECO employees, which allows for NU common shares to be purchased by employees at six-month intervals at 95 percent of the closing market price on the last day of each six-month period. Employees are permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the purchase period up to a limit of $25,000 per annum. The ESPP qualifies as a non-compensatory plan under accounting guidance for share-based payments, and no compensation expense is recorded for ESPP purchases.

During 2010 and 2009, employees purchased 38,672 and 39,264 shares, respectively, at discounted prices of $26.45 and $24.05 in 2010 and $22.61 and $21.86 in 2009. As of December 31, 2010 and 2009, 932,178 and 970,850 shares, respectively, remained available for future issuance under the ESPP.

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards. The Company generally settles stock option exercises and fully vested RSUs and performance shares with the issuance of new common shares.

E.

Other Retirement Benefits

NU provides benefits for retirement and other benefits for certain current and past company officers of NU, including CL&P, PSNH and WMECO. The actuarially-determined liability for these benefits, which is included in Other Long-Term Liabilities on the accompanying consolidated balance sheets, was $49.9 million ($0.4 million for CL&P, $2.4 million for PSNH and $0.2 million for WMECO) and $47.9 million ($0.4 million for CL&P, $2.4 million for PSNH and $0.2 million for WMECO) as of December 31, 2010 and 2009, respectively. During 2010, 2009 and 2008, $4.2 million ($2.3 million for CL&P, $0.9 million for PSNH and $0.4 million for WMECO), $3.9 million ($2.2 million for CL&P, $0.9 million for PSNH and $0.4 million for WMECO) and $3.8 million ($2.2 million for CL&P, $0.8 million for PSNH and $0.4 million for WMECO), respectively, was expensed related to these benefits. These benefits are accounted for on an accrual basis and expensed over the service lives of the employees in accordance with accounting guidance for deferred compensation contracts.

11.

INCOME TAXES

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting authoritative literature. Details of income tax expense and the components of the federal and state income tax provisions are as follows:

	For the Years Ended December 31,		
	2010	**2009**	**2008**
(Millions of Dollars)	**NU**	**NU**	**NU**
Current Income Taxes:			
Federal	$ 9.0	$ 4.5	$ 6.0
State	(6.5)	52.7	16.3
Total Current	2.5	57.2	22.3
Deferred Income Taxes, Net:			
Federal	201.2	155.1	100.2
State	9.7	(29.2)	(13.4)
Total Deferred	210.9	125.9	86.8
Investment Tax Credits, Net	(3.0)	(3.2)	(3.4)
Income Tax Expense	$ 210.4	$ 179.9	$ 105.7

	For the Years Ended December 31,								
		2010			**2009**			**2008**	
	CL&P	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**

(Millions of Dollars)									
Current Income Taxes:									
Federal	$ 20.7	$ 6.1	$ 3.1	$ 28.3	$ (8.9)	$ (8.6)	$ 13.9	$ 0.8	$ (1.4)
State	(1.1)	5.6	2.5	40.1	5.8	0.9	19.0	(3.6)	-
Total Current	19.6	11.7	5.6	68.4	(3.1)	(7.7)	32.9	(2.8)	(1.4)
Deferred Income Taxes, Net:									
Federal	108.1	37.6	11.0	80.5	34.4	21.3	68.0	17.4	10.4
State	7.0	1.6	-	(27.6)	0.8	1.6	(20.4)	7.6	1.8
Total Deferred	115.1	39.2	11.0	52.9	35.2	22.9	47.6	25.0	12.2
Investment Tax Credits, Net	(2.3)	(0.1)	(0.3)	(2.5)	(0.1)	(0.3)	(2.6)	(0.2)	(0.2)
Income Tax Expense	$ 132.4	$ 50.8	$ 16.3	$ 118.8	$ 32.0	$ 14.9	$ 77.9	$ 22.0	$ 10.6

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

	For the Years Ended December 31,		
	2010	**2009**	**2008**
(Millions of Dollars, except percentages)	**NU**	**NU**	**NU**
Income Before Income Tax Expense	$ 604.5	$ 515.5	$ 372.0
Statutory Federal Income Tax Expense at 35%	211.6	180.4	130.2
Tax Effect of Differences:			
Depreciation	(9.5)	(2.7)	(12.9)
Investment Tax Credit Amortization	(3.0)	(3.2)	(3.4)
Other Federal Tax Credits	(3.8)	(3.8)	(4.6)
State Income Taxes, Net of Federal Impact	12.5	11.5	(9.5)
Medicare Subsidy	15.6	(3.5)	(4.2)
Tax Asset Valuation Allowance/Reserve Adjustments	(10.5)	3.8	12.5
Other, Net	(2.5)	(2.6)	(2.4)
Income Tax Expense	$ 210.4	$ 179.9	$ 105.7
Effective Tax Rate	34.8 %	34.9 %	28.4 %

	For the Years Ended December 31,								
	2010			2009			2008		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Income Before Income Tax Expense	$ 376.6	$ 140.9	$ 39.4	$ 335.2	$ 97.6	$ 41.1	$ 269.0	$ 80.1	$ 28.9
Statutory Federal Income Tax Expense at 35%	131.8	49.3	13.8	117.3	34.1	14.4	94.2	28.0	10.1
Tax Effect of Differences:									
Depreciation	(6.1)	(3.2)	0.2	(1.7)	(1.2)	0.3	(11.1)	(1.8)	0.1
Investment Tax Credit Amortization	(2.3)	(0.1)	(0.3)	(2.5)	(0.1)	(0.3)	(2.6)	(0.2)	(0.2)
Other Federal Tax Credits	(0.1)	(3.6)	-	(0.1)	(3.7)	-	(1.2)	(3.4)	-
State Income Taxes, Net of Federal Impact	8.5	4.7	1.6	8.9	4.3	1.6	(18.5)	2.6	1.2
Medicare Subsidy	7.8	3.8	1.5	(1.3)	(0.6)	(0.3)	(1.5)	(0.8)	(0.4)
Tax Asset Valuation Allowance/ Reserve Adjustments	(4.7)	-	-	(0.8)	-	-	19.8	-	-
Other, Net	(2.5)	(0.1)	(0.5)	(1.0)	(0.8)	(0.8)	(1.2)	(2.4)	(0.2)
Income Tax Expense	$ 132.4	$ 50.8	$ 16.3	$ 118.8	$ 32.0	$ 14.9	$ 77.9	$ 22.0	$ 10.6
Effective Tax Rate	35.2 %	36.1 %	41.4 %	35.4 %	32.8 %	36.3 %	28.9 %	27.5 %	36.7 %

NU, CL&P, PSNH, and WMECO file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

The tax effects of temporary differences that give rise to the current and long-term net accumulated deferred tax obligations are as follows:

	As of December 31,			
	2010		2009	
(Millions of Dollars)	NU		NU	
Deferred Tax Liabilities - Current:				
Derivative Asset and Change in Fair Value of Energy Contracts	$	3.2	$	8.5
Property Tax Accruals and Other		63.1		49.3
Total Deferred Tax Liabilities - Current		66.3		57.8
Deferred Tax Assets - Current:				
Derivative Liability and Change in Fair Value of Energy Contracts		23.9		17.5
Allowance for Uncollectible Accounts and Other		91.8		50.1
Total Deferred Tax Assets - Current		115.7		67.6
Net Deferred Tax Assets - Current		49.4		9.8
Deferred Tax Liabilities - Long-Term:				
Accelerated Depreciation and Other Plant-Related Differences		1,612.6		1,351.0
Regulatory Amounts:				
Securitized Contract Termination Costs		65.8		101.6
Other Regulatory Deferrals		873.3		848.6
Tax Effect - Tax Regulatory Assets		177.1		179.8
Derivative Assets		44.8		71.6
Other		18.3		28.2
Total Deferred Tax Liabilities - Long-Term		2,791.9		2,580.8
Deferred Tax Assets Long-Term:				
Regulatory Deferrals		135.5		133.0
Employee Benefits		457.8		493.1
Tax Effect - Tax Regulatory Assets		17.0		25.8
Derivative Liability		352.6		374.9
Other		154.9		193.7
Total Deferred Tax Assets - Long-Term		1,117.8		1,220.5
Less: Valuation Allowance		19.8		19.8
Net Deferred Tax Assets - Long-Term		1,098.0		1,200.7
Net Deferred Tax Liabilities - Long-Term		1,693.9		1,380.1
Net Deferred Tax Liabilities	$	1,644.5	$	1,370.3
Total Deferred Tax Assets	$	1,233.5	$	1,288.1
Total Deferred Tax Liabilities	$	2,858.2	$	2,638.6

	As of December 31,					
		2010			2009	
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred Tax Assets - Current:						
Derivative Liability and Change in Fair Value of Energy Contracts	$ 18.7	$ 5.1	$ -	$ 2.6	$ 7.4	$ -
Allowance for Uncollectible Accounts and Other	60.2	11.2	2.0	25.3	6.0	2.8
Total Deferred Tax Assets Current	78.9	16.3	2.0	27.9	13.4	2.8
Deferred Tax Liabilities - Current:						
Derivative Assets and Change in Fair Value of Energy Contracts	3.1	-	-	8.3	0.2	-
Property Tax Accruals and Other	43.4	5.6	3.7	31.2	5.1	3.0
Total Deferred Tax Liabilities Current	46.5	5.6	3.7	39.5	5.3	3.0
Net Deferred Tax Liabilities/(Assets) - Current	(32.4)	(10.7)	1.7	11.6	(8.1)	0.2
Deferred Tax Assets - Long-Term:						
Regulatory Deferrals	68.9	34.4	6.5	70.0	36.2	5.4
Employee Benefits	63.9	121.8	1.8	85.2	135.1	8.3
Income Tax Gross-Up	7.4	1.6	6.9	12.8	2.2	7.2
Derivative Liability	352.5	-	-	364.5	3.0	-
Other	56.8	8.5	14.3	88.8	9.5	8.4
Net Deferred Tax Assets Long-Term	549.5	166.3	29.5	621.3	186.0	29.3
Deferred Tax Liabilities - Long-Term:						
Accelerated Depreciation and Other Plant-Related Differences	917.0	309.8	168.4	754.1	263.1	152.8
Regulatory Amounts:						
Securitized Contract Termination Costs	(0.8)	50.4	16.2	9.6	69.9	22.1
Other Regulatory Deferrals	546.6	105.1	51.1	536.2	111.1	51.2
Income Tax Gross-Up	138.5	14.0	13.7	145.3	10.9	14.0
Derivative Assets	44.8	-	-	71.4	-	-
Other	4.5	14.3	2.4	6.2	6.7	0.6
	1,650.6	493.6	251.8	1,522.8	461.7	240.7

Total Deferred Tax Liabilities - Long-Term						
Net Deferred Tax Liabilities - Long-Term	1,101.1	327.3	222.3	901.5	275.7	211.4
Net Deferred Tax Liabilities	$ 1,068.7	$ 316.6	$ 224.0	$ 913.1	$ 267.6	$ 211.6
Total Deferred Tax Assets	$ 628.4	$ 182.6	$ 31.5	$ 649.2	$ 199.4	$ 32.1
Total Deferred Tax Liabilities	$ 1,697.1	$ 499.2	$ 255.5	$ 1,562.3	$ 467.0	$ 243.7

Net Deferred Tax Liabilities/(Assets) - Current are recorded as current liabilities or assets and are included in Other Current Liabilities or Prepayments and Other Current Assets, respectively, on the accompanying consolidated balance sheets.

As of December 31, 2010, NU had state net operating loss carryforwards of $317.7 million that expire between December 31, 2011 and December 31, 2027 and state credit carryforwards of $84.9 million that begin expiring in 2013. As of December 31, 2009, NU had state net operating loss carryforwards of $323.9 million that expire between December 31, 2010 and December 31, 2027 and state credit carryforwards of $88.7 million that expire by December 31, 2014. The net operating loss carryforward deferred tax asset has been fully reserved by a valuation allowance. As of December 31, 2010, CL&P had state tax credit carryforwards of $56.1 million that expire by 2014. As of December 31, 2009, CL&P had state tax credit carryforwards of $61.1 million that expire by 2014.

Unrecognized Tax Benefits: As of December 31, 2010, NU and CL&P had unrecognized tax benefits totaling $101.2 million and $80.8 million, respectively, all of which would impact the effective tax rate if recognized. As of December 31, 2009, NU and CL&P had unrecognized tax benefits totaling $124.3 million and $89 million, respectively, all of which would impact the effective tax rate if recognized. As of December 31, 2008, the portion of NU and CL&P unrecognized tax benefits that would impact the effective tax rate, if recognized, were $120 million and $87 million, respectively. A reconciliation of the activity in unrecognized tax benefits from January 1, 2008 to December 31, 2010 is as follows:

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
Balance as of January 1, 2008	$ 121.1	$ 75.9	$ 10.6	$ 2.9
Gross Increases - Current Year	28.6	24.9	-	-
Gross Increases - Prior Year	7.4	5.6	1.8	0.9
Lapse of Statute of Limitations	(0.8)	-	-	-
Balance as of December 31, 2008	156.3	106.4	12.4	3.8
Gross Increases - Current Year	12.3	8.6	-	-
Settlement	(44.2)	(26.0)	(12.4)	(3.8)
Lapse of Statute of Limitations	(0.1)	-	-	-
Balance as of December 31, 2009	124.3	89.0	-	-
Gross Increases - Current Year	10.8	5.3	-	-
Gross Increases - Prior Year	0.8	-	-	-
Settlement	(34.3)	(13.5)	-	-
Lapse of Statute of Limitations	(0.4)	-	-	-
Balance as of December 31, 2010	$ 101.2	$ 80.8	$ -	$ -

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the accompanying consolidated statements of income. No penalties have been recorded. The components of interest on uncertain tax positions by company in 2010, 2009 and 2008 are as follows:

Other Interest Expense/(Income)	**For the Years Ended December 31, 2010**	**2009**	**2008**
(Millions of Dollars)			
CL&P	$ (7.4)	$ (4.2)	$ 4.8
PSNH	0.1	(1.3)	-
WMECO	-	(0.4)	0.2
NU Parent and Other	(17.5)	1.9	3.2
Total	$ (24.8)	$ (4.0)	$ 8.2

Accrued Interest Expense/(Income)	**As of December 31, 2010**	**2009**
(Millions of Dollars)		
CL&P	$ 6.4	$ 13.8
PSNH	0.6	0.5
WMECO	-	-
NU Parent and Other	2.9	20.4
Total	$ 9.9	$ 34.7

Tax Positions: During 2010, NU settled various tax matters including state obligations, which resulted in the recognition during the year of an after-tax gain of approximately $35 million. This gain is recorded as a reduction to both interest expense and income tax expense (including NU and CL&P tax expense reductions of approximately $6 million and $4 million, respectively). NU is currently working to resolve the treatments of certain timing and other costs in the remaining open periods.

Tax Years: The following table summarizes NU, CL&P, PSNH and WMECO's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2010:

Description	**Tax Years**
Federal	2009-2010
Connecticut	2005-2010
New Hampshire	2007-2010
Massachusetts	2007-2010

While tax audits are currently ongoing, it is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions of differences of a non-timing nature, could result in a zero to $77 million decrease in unrecognized tax benefits by NU and a zero to $67 million decrease in unrecognized tax benefits by CL&P. These estimated changes could have an impact on NU's and CL&P's 2011 earnings of zero to $38 million and zero to $34 million, respectively. Other companies impacts are not expected to be material.

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 2010. Since the electric and natural gas distribution companies are cost-of-service and rate-regulated, a portion of the $18 million is 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.

12.

COMMITMENTS AND CONTINGENCIES

A.

Environmental Matters

General: NU, CL&P, PSNH, and WMECO are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. NU, CL&P, PSNH, and WMECO have an active environmental auditing and training program and believe that they are substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring.

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of NU, CL&P, PSNH, and WMECO's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities included in Other Long-Term Liabilities on the accompanying consolidated balance sheets represent management's best estimate of the liability for environmental costs, and take into consideration site assessment and remediation costs. NU, CL&P, PSNH, and WMECO's environmental liability also takes into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate previously contaminated sites and any other infrequent and non-recurring clean up costs. A reconciliation of the activity in the environmental reserves as is as follows:

(Millions of Dollars)	NU	CL&P	PSNH	WMECO
Balance as of December 31, 2008	$ 27.4	$ 2.8	$ 5.5	$ 0.3
Additions	2.3	0.3	0.1	0.4
Payments	(3.7)	(0.4)	(0.3)	(0.3)
Balance as of December 31, 2009	26.0	2.7	5.3	0.4
Additions	18.2	0.5	8.9	0.1
Payments	(7.1)	(0.4)	(5.1)	(0.2)
Balance as of December 31, 2010	$ 37.1	$ 2.8	$ 9.1	$ 0.3

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. NU, CL&P, PSNH, and WMECO have not recorded any probable recoveries from third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

It is possible that new information or future developments could require a reassessment of the potential exposure to related environmental matters. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

As of December 31, 2010, the status of environmental sites are as follows:

(Number of Sites)	NU	CL&P	PSNH	WMECO
Remediation or long-term monitoring phase	33	6	12	8
Some site assessment completed	19	9	2	1
Preliminary site assessment stage	6	2	4	-
Total environmental sites	58	17	18	9

The environmental reserve related to these sites is as follows:

	As of December 31,							
	2010				2009			
	NU	CL&P	PSNH	WMECO	NU	CL&P	PSNH	WMECO
Remediation or long-term monitoring phase	$ 30.3	$ 0.8	$ 8.8	$ 0.2	$ 18.4	$ 0.5	$ 5.0	$ 0.2
Preliminary site assessment stage	6.5	1.9	0.1	0.1	7.3	2.1	0.2	0.2
Some site assessment completed	0.3	0.1	-	-	0.3	0.1	0.1	-

Total	$	37.1	$	2.8	$	0.3	$	0.3	$	26.0	$	2.7	$	5.3	0.4

The majority of the accruals for sites in remediation or long-term monitoring relate to MGP sites that were operated several decades ago and produced manufacturing gas from coal, which resulted in certain byproducts in the environment that may pose a risk to human health and the environment.

As of December 31, 2010, for 8 environmental sites (3 for CL&P, 2 for PSNH, and 1 for WMECO) that are included in the Company's reserve for environmental costs, the information known and nature of the remediation options at those sites allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2010, $8.4 million ($1.5 million for CL&P, $0.7 million for PSNH, and $0.1 million for WMECO) had been accrued as a liability for these sites, which represent management's best estimates of the liabilities for environmental costs. These amounts are the best estimates within estimated ranges of losses from $4.5 million to $25 million ($1.3 million to $5.7 million for CL&P, zero to $4.1 million for PSNH, and zero to $8.7 million for WMECO). For the 50 remaining sites (14 for CL&P, 16 for PSNH, and 8 for WMECO) that comprise the remaining $28.7 million of the environmental reserve ($1.3 million for CL&P, $8.4 million for PSNH and $0.2 million for WMECO), determining an estimated range of loss is not possible at this time.

As of December 31, 2010, in addition to the sites identified above, there were 12 sites (7 for CL&P, 2 for PSNH, and 2 for WMECO) for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time.

HWP: 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 a MGP site that HWP sold to HG&E, a municipal utility, in 1902. HWP shares responsibility for site remediation with HG&E and has conducted substantial investigative and remediation activities. The cumulative expense recorded to the reserve for this site since 1994 through December 31, 2010 was $19.5 million, of which $16.6 million had been spent, leaving $2.9 million in the reserve as of December 31, 2010. For the years ended December 31, 2010, 2009 and 2008, pre-tax charges of $2.6 million, $1.1 million and $3 million, respectively, were recorded to reflect estimated costs associated with the site. HWP's share of the costs related to this site is not recoverable from customers.

In 2008, the MA DEP issued a letter to HWP and HG&E, representing guidance rather than a mandate, providing conditional authorization for additional investigatory and risk characterization activities and indicating that further removal of tar in certain areas was needed. HWP implemented several supplemental studies to further delineate and assess tar deposits in conformity with the MA DEP's guidance letter.

In 2010, HWP delivered a report to the MA DEP describing the results of its site investigation studies and testing. Subsequent communications and discussions with the MA DEP have focused on the course of action to achieve resolution of these matters, and are ongoing.

The $2.9 million reserve balance as of December 31, 2010 represents estimated costs that HWP considers probable over the remaining life of the project, including testing and related costs in the near term and field activities to be agreed upon with the MA DEP, further studies and long-term monitoring that are expected to be required by the MA DEP, and certain soft tar remediation activities. Various factors could affect management's estimates and require an increase to the reserve, which would be reflected as a charge to Net Income. 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.

CERCLA: CERCLA and its amendments or state equivalents impose joint and several strict liabilities, regardless of fault, upon generators of hazardous substances resulting in removal and remediation costs and environmental damages. Liabilities under these laws can be material and in some instances may be imposed without regard to fault or for past acts that may have been lawful at the time they occurred. Of the total sites included in the remediation and long-term monitoring phase, 5 sites (3 for PSNH, 2 for CL&P, and 1 for WMECO) are superfund sites under CERCLA for which the Company has been notified that it is a potentially responsible party but for which the site assessment and remediation are not being managed by the Company. As of December 31, 2010, a liability of $0.7 million ($0.4 million for CL&P, $0.3 million for PSNH, and a de minimis amount for WMECO) accrued on these sites represents management's best estimate of its potential remediation costs with respect to these superfund sites.

Environmental Rate Recovery: PSNH and Yankee Gas have rate recovery mechanisms for environmental costs. CL&P recovers a certain level of environmental costs currently in rates but does not have an environmental cost recovery tracking mechanism. Accordingly, changes in CL&P's environmental reserves impact CL&P's Net Income. WMECO does not have a separate regulatory mechanism to recover environmental costs from its customers, and changes in WMECO's environmental reserves impact WMECO's Net Income.

B.

Spent Nuclear Fuel Disposal Costs (CL&P, WMECO)

Under the Nuclear Waste Policy Act of 1982, CL&P and WMECO must pay the DOE for the costs of disposal of spent nuclear fuel and high-level radioactive waste for the period prior to the sale of their ownership shares in the Millstone nuclear power stations.

The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Spent Nuclear Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made by CL&P and WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P and WMECO remained responsible for their share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability

will continue to accrue interest at the 3-month treasury bill yield rate. Fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel as of December 31, 2010 and 2009 are included in Long-Term Debt and were $301 million and $300.6 million ($243.8 million and $243.5 million for CL&P and $57.2 million and $57.1 million for WMECO), respectively, including accumulated interest costs of $218.9 million and $218.5 million ($177.3 million and $177 million for CL&P and $41.6 million and $41.5 million for WMECO), respectively.

In 2004, WMECO established a trust that holds marketable securities to fund amounts due to the DOE for the disposal of WMECO's Prior Period Spent Nuclear Fuel. For further information on this trust, see Note 5, "Marketable Securities," to the consolidated financial statements.

C.

Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant long-term contractual arrangements as of December 31, 2010 are as follows:

NU

(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Totals**
VYNPC	$ 30.2	$ 7.6	$ 0.2	$ -	$ -	$ -	$ 38.0
Supply/Stranded Cost Contracts/Obligations	243.2	289.3	280.5	265.9	196.4	858.2	2,133.5
Renewable Energy Contracts	16.6	87.4	112.0	142.0	147.8	2,044.7	2,550.5
Peaker CfDs	27.7	54.0	60.6	63.6	62.9	297.4	566.2
Natural Gas Procurement Contracts	61.4	55.5	31.3	29.3	25.3	90.6	293.4
Wood, Coal and Transportation Contracts	118.5	116.9	10.1	-	-	-	245.5
PNGTS Pipeline Commitments	3.1	3.1	3.1	3.1	3.1	9.8	25.3
Transmission Support Commitments	20.6	20.4	20.3	19.8	20.7	103.4	205.2
Yankee Companies Billings	27.4	28.4	28.1	26.8	22.4	-	133.1
Select Energy Purchase Agreements	43.0	42.8	48.7	-	-	-	134.5
Clean Air Project Commitments	49.5	14.0	2.0	-	-	-	65.5
Totals	$ 641.2	$ 719.4	$ 596.9	$ 550.5	$ 478.6	$ 3,404.1	$ 6,390.7

CL&P

(Millions of Dollars)	2011	2012	2013	2014	2015	Thereafter	Totals
VYNPC	$ 17.9	$ 4.5	$ 0.1	$ -	$ -	$ -	$ 22.5
Supply/Stranded Cost Contracts/Obligations	191.4	238.1	233.0	216.1	159.5	728.2	1,766.3
Renewable Energy Contracts	16.6	87.4	112.0	142.0	147.8	2,044.7	2,550.5
Peaker CfDs	27.7	54.0	60.6	63.6	62.9	297.4	566.2
Transmission Support Commitments	11.8	11.6	11.6	11.3	11.8	59.2	117.3
Yankee Companies Billings	18.8	19.5	19.2	18.5	15.7	-	91.7
Totals	$ 284.2	$ 415.1	$ 436.5	$ 451.5	$ 397.7	$ 3,129.5	$ 5,114.5

PSNH

(Millions of Dollars)	2011	2012	2013	2014	2015	Thereafter	Totals
VYNPC	$ 7.5	$ 1.9	$ 0.1	$ -	$ -	$ -	$ 9.5
Supply/Stranded Cost Contracts/Obligations	51.8	51.2	47.5	49.8	36.9	130.0	367.2
Wood, Coal and Transportation Contracts	118.5	116.9	10.1	-	-	-	245.5
PNGTS Pipeline Commitments	3.1	3.1	3.1	3.1	3.1	9.8	25.3
Transmission Support Commitments	6.3	6.4	6.3	6.1	6.4	31.8	63.3
Yankee Companies Billings	3.4	3.6	3.6	3.2	2.3	-	16.1
Clean Air Project Commitments	49.5	14.0	2.0	-	-	-	65.5
Totals	$ 240.1	$ 197.1	$ 72.7	$ 62.2	$ 48.7	$ 171.6	$ 792.4

WMECO

(Millions of Dollars)	2011	2012	2013	2014	2015	Thereafter	Totals
VYNPC	$ 4.7	$ 1.2	$ -	$ -	$ -	$ -	$ 5.9
Transmission Support Commitments	2.5	2.4	2.4	2.4	2.5	12.4	24.6
Yankee Companies Billings	5.2	5.3	5.3	5.1	4.4	-	25.3
Totals	$ 12.4	$ 8.9	$ 7.7	$ 7.5	$ 6.9	$ 12.4	$ 55.8

VYNPC: CL&P, PSNH, and WMECO have commitments to buy approximately 9.5 percent, 4 percent, and 2.5 percent (16 percent in the aggregate for NU), respectively, of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March 2012 at a range of fixed prices. CL&P, PSNH, and WMECO's total cost of purchases under contracts with VYNPC amounted to $16 million, $6.7 million, and $4.2 million, respectively, in 2010, $17.5 million, $7.3 million, and $4.6 million, respectively, in 2009, and $15.7 million, $6.6 million, and $4.2 million, respectively, in 2008 ($26.9 million in 2010, $29.4 million in 2009 and $26.5 million in 2008 in the aggregate for NU).

Supply/Stranded Cost Contracts/Obligations: CL&P and PSNH have various IPP contracts or purchase obligations for electricity, including payment obligations resulting from the buydown of electricity purchase contracts. Excluding renewable and CfD contracts, which are discussed below, such contracts extend through 2024 for CL&P. At PSNH such contracts extend through 2023. The total cost of purchases and obligations under these contracts/obligations amounted to $196.2 million, ($151.3 million for CL&P, $42.6 million for PSNH, and $2.3 million for WMECO) in 2010, $205.3 million, ($173.1 million for CL&P, $29.8 million for PSNH, and $2.4 million for WMECO) in 2009, and $237.6 million ($200.5 million for CL&P, $34.6 million for PSNH, and $2.5 million for WMECO) in 2008.

In addition, CL&P and UI have entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects being built or modified and one demand response project. The capacity CfDs extend through 2026 and obligate the utilities to pay the difference between a set price and the value that the projects receive in the ISO-NE markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers. The information in the table above includes 100 percent of the payments projected as of December 31, 2010 under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI. The amounts of these payments are subject to changes in capacity and forward reserve prices that the projects receive in the ISO-NE capacity markets. 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 CfD. This event could delay or change CL&P's estimated payments under the CfD contract.

These amounts do not include contractual commitments related to CL&P's standard or last resort service or WMECO's default service, both of which represent contractual commitments that are conditional upon CL&P and WMECO customers' use of energy, and PSNH's short-term power supply management.

Renewable Energy Contracts: CL&P has entered into various agreements to purchase energy, capacity and renewable energy credits from renewable energy facilities. Amounts payable under these contracts are subject to a sharing agreement with UI, whereby UI will share approximately 20 percent of the costs and benefits of these contracts. In addition, UI has entered into contracts that are subject to this cost sharing agreement under which CL&P will share in approximately 80 percent of the costs and benefits of the contract. The information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

Peaker CfDs: In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the DPUC (Peaker CfDs). These units will have a total of approximately 500 MW of peaking capacity. As directed by the DPUC, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The information in the table above includes 100 percent of the estimated payments projected under the contracts, before reimbursement from UI under the sharing agreement. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from or refunded to CL&P's customers.

Natural Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of natural gas in the normal course of business as part of its portfolio of supplies. These contracts extend through 2022. The total cost of Yankee Gas' procurement portfolio, including these contracts, amounted to $209.5 million in 2010, $236.3 million in 2009 and $352.5 million in 2008.

Wood, Coal and Transportation Contracts: PSNH has entered into various arrangements for the purchase of wood, coal and the transportation services for fuel supply for its electric generating assets. PSNH's fuel and natural gas costs, excluding emissions allowances, amounted to approximately $168.3 million in 2010, $156.7 million in 2009 and $165.4 million in 2008.

PNGTS Pipeline Commitments: PSNH has a contract for capacity on the Portland Natural Gas Transmission System (PNGTS) pipeline that extends through 2018. The cost under this contract amounted to $2.8 million in 2010, $1.6 million in 2009 and $1.5 million in 2008. These costs are not recovered from PSNH's retail customers.

Transmission Support Commitments: Along with other New England utilities, CL&P, PSNH and WMECO entered into agreements in 1985 to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, PSNH and WMECO are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities. CL&P, PSNH and WMECO's total cost of these agreements amounted to $10.8 million, $5.8 million and $2.3 million, respectively, in 2010, $10.7 million, $5.7 million and $2.2 million, respectively, in 2009, and $10.5 million, $5.6 million and $2.2 million, respectively, in 2008 ($18.9 million in 2010, $18.6 million in 2009 and $18.3 million in 2008 in the aggregate for NU).

Yankee Companies Billings: CL&P, PSNH and WMECO have significant decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. CL&P, PSNH and WMECO's total cost of these billings amounted to $22.7 million, $4.1 million and $6.2 million, respectively, in 2010, $18.2 million, $3.7 million and $5 million, respectively, in 2009, and $20 million, $4.4 million and $5.4 million, respectively, in 2008 ($33 million in 2010, $26.9 million in 2009 and $29.8 million in 2008 in the aggregate for NU).

See Note 12D "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

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Clean Air Project Commitments: These amounts represent commitments for engineering, program management services and major component supply and installation associated with PSNH's coal-fired 440 MW Merrimack Station clean air project, which includes the addition of a wet scrubber to reduce mercury and SO_2 emissions at Merrimack Station Units 1 and 2. The total cost under these contracts amounted to $129.6 million in 2010, $107.5 million in 2009 and $20.5 million in 2008.

Select Energy Purchase Agreements: Select Energy maintains long-term agreements to purchase energy as part of its portfolio of resources to meet its actual or expected sales commitments. Most purchase commitments are recorded at their mark-to-market value with the exception of one nonderivative contract, which is accounted for on the accrual basis.

Select Energy's purchase commitment amounts are reported on a net basis in Fuel, Purchased and Net Interchange Power on the accompanying consolidated statements of income along with certain sales contracts and mark-to-market amounts. Accordingly, the amount included in Fuel, Purchased and Net Interchange Power will be less than the amounts included in the table above. Select Energy also maintains certain energy commitments whose mark-to-market values have been recorded on the consolidated balance sheets as Derivative Assets and Liabilities. These contracts are included in the table above.

D.

Deferred Contractual Obligations

CL&P, PSNH and WMECO have decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates.

CL&P, PSNH and WMECO's percentage share of the obligations to support the Yankee Companies under FERC-approved rate tariffs is the same as their respective ownership percentages in the Yankee Companies. For further information on the ownership percentages, see Note 1L, "Summary of Significant Accounting Policies - Equity Method Investments," to the consolidated financial statements.

The Yankee Companies are currently collecting amounts that management believes are adequate to recover the remaining decommissioning and closure cost estimates for the respective plants. Management believes CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. PSNH has already recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 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 2007, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December 2006, the DOE appealed the ruling, and the Yankee Companies filed cross-appeals. The Court of Appeals issued its decision on August 7, 2008, effectively agreeing with the trial court's findings as to the liability of the DOE but disagreeing with the method that the trial court used to calculate damages. The Court of Appeals vacated the decision and remanded the case for new findings consistent with its decision.

On September 7, 2010, the trial court issued its decision following remand, and judgment on the decision was entered on September 9, 2010. The judgment 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 on November 8, 2010. Briefs will be due absent extensions during the first quarter of 2011. Interest on the judgments does not start to accrue until all appeals have been decided and/or all appeal periods have expired without appeals being filed. The application of any damages, which 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.

The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery the Yankee Companies may obtain from the DOE on this matter. However, NU believes that any net settlement proceeds it receives would be incorporated into FERC-approved recoveries, which would be passed on to its customers, through reduced charges.

E.

Guarantees and Indemnifications

NU parent provides credit assurances on behalf of its subsidiaries, including CL&P, PSNH and WMECO, in the form of guarantees and LOCs in the normal course of business.

NU has also provided guarantees and various indemnifications on behalf of external parties as a result of the sale of SESI, formerly a subsidiary of NU Enterprises, with an aggregate fair value amount recorded of $0.3 million. Other indemnifications in connection with the sale of SESI include specific indemnifications for estimated costs to complete or modify specific projects, indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts, and surety bonds covering certain projects. The maximum exposure on these items is either not specified or not material, and no amounts are recorded as liabilities. NU parent also provided guarantees and various indemnifications on behalf of external parties as a result of the sales of NU Enterprises' former retail marketing business and competitive generation business. These included indemnifications for compliance with tax and environmental laws, and various claims for which the maximum exposure was not specified in the sale agreements.

In October 2010, NU issued a guaranty for the benefit of Hydro Renewable Energy under which NU guaranteed the financial obligations of NPT under the TSA in an amount not to exceed $18.8 million. NU's obligations under the guaranty arise at the time the Northern Pass Transmission line goes into commercial operation and expires upon the full, final and indefeasible payment of the guaranteed obligations.

Management does not anticipate a material impact to net income to result from these various guarantees and indemnifications. The following table summarizes the NU, including CL&P, PSNH, and WMECO, maximum exposure as of December 31, 2010, in accordance with guidance on guarantor's accounting and disclosure requirements for guarantees and expiration dates:

Subsidiary	**Description**	**Maximum Exposure (in millions)**	**Expiration Dates**
Various	Surety Bonds	$ 11.8	January 2011 - June 2012 (1)
PSNH and Select Energy	Letters of Credit	$ 32.1	October 2011 - November 2011
RRR and NUSCO	Lease Payments for Real Estate and Vehicles	$ 21.4	2019-2024
NU Enterprises	Surety Bonds, Insurance Bonds and Performance Guarantees	$ 121.5(2)	(2)

(1)

Surety bond expiration dates reflect bond termination dates, the majority of which will be renewed or extended.

(2)

The maximum exposure includes $64.8 million related to performance guarantees on Select Energy's wholesale purchase contracts, which expire in 2013 assuming purchase contracts guaranteed have no value; however, actual exposures vary with underlying commodity prices. The maximum exposure also includes $17.5 million related to a performance guarantee of NGS obligations for which no maximum exposure is specified in the agreement. The maximum exposure was calculated as of December 31, 2010 based on limits of NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. Also included in the maximum exposure is $1.1 million related to insurance bonds at NGS with no expiration date that are billed annually on their anniversary date. The remaining $38.1 million of maximum exposure relates to surety bonds covering ongoing projects at Boulos, which expire upon project completion.

CL&P, PSNH and WMECO do not guarantee the performance of third parties.

Many of the underlying contracts that NU parent guarantees, as well as certain surety bonds, contain credit ratings triggers that would require NU parent to post collateral in the event that the unsecured debt credit ratings of NU are downgraded below investment grade.

F.

Litigation and Legal Proceedings

NU, including CL&P, PSNH and WMECO, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, discloses matters when losses are probable but not estimable or reasonably possible, and expenses legal costs related to the defense of loss contingencies as incurred.

13.

LEASES

Various NU subsidiaries, including CL&P, PSNH and WMECO, have entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. In addition, CL&P, PSNH and WMECO incur costs associated with leases entered into by NUSCO and RRR. These costs are included below in CL&P, PSNH and WMECO's operating lease payments charged to expense and amounts capitalized as well as future operating lease payments from 2011 through 2015 and thereafter. These amounts are eliminated on an NU consolidated basis. The provisions of these lease agreements generally contain renewal options. Certain lease agreements contain contingent lease payments. The contingent lease payments are based on various factors, such as the commercial paper rate plus a credit spread or the consumer price index.

For the years ended December 31, 2010, 2009, and 2008, rental payments made on capital leases, interest included in capital lease payments, and capital lease asset amortization were as follows:

(Millions of Dollars)	**Rental Payments**			**Interest**			**Asset Amortization**		
	NU	**CL&P**	**PSNH**	**NU**	**CL&P**	**PSNH**	**NU**	**CL&P**	**PSNH**
2010	$ 2.5	$ 1.9	$ 0.5	$ 1.8	$ 1.5	$ 0.3	$ 0.7	$ 0.4	$ 0.2
2009	2.6	1.9	0.5	1.9	1.6	0.3	0.6	0.3	0.2
2008	2.5	2.1	0.4	1.8	1.7	0.1	0.7	0.4	0.3

There was a de minimis amount of capital leases held by WMECO in 2010, 2009, and 2008.

For the years ended December 31, 2010, 2009 and 2008, operating lease rental payments charged to expense and the capitalized portion of operating lease payments were as follows:

	Expensed				Capitalized			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
2010	$ 11.9	$ 10.0	$ 2.2	$ 2.6	$ 4.8	$ 3.8	$ 0.1	$ 0.1
2009	18.1	12.8	3.9	3.4	9.7	6.1	1.5	1.1
2008	19.1	12.7	4.1	3.8	10.8	6.8	1.8	1.3

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 2010 are as follows:

Capital Leases

(Millions of Dollars)	**NU**	**CL&P**	**PSNH**
2011	$ 2.5	$ 1.9	$ 0.5
2012	2.6	2.0	0.5
2013	2.4	2.0	0.4
2014	2.0	1.8	0.2
2015	2.0	1.8	0.2
Thereafter	11.4	11.3	0.1
Future minimum lease payments	22.9	20.8	1.9
Less amount representing interest	10.7	10.2	0.5
Present value of future minimum lease payments	$ 12.2	$ 10.6	$ 1.4

Operating Leases

(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**
2011	$ 7.9	$ 7.2	$ 2.0	$ 3.0
2012	7.0	6.8	1.8	2.9
2013	6.8	6.7	1.7	2.8

2014	4.9	6.5	1.7	1.3
2015	4.5	6.5	1.7	0.9
Thereafter	19.1	23.0	5.3	2.6
Future minimum lease payments	$ 50.2	$ 56.7	$ 14.2	$ 13.5

In November 2008, the lessor of CL&P, PSNH, WMECO and Yankee Gas' vehicle/equipment master lease agreements notified the companies that it was electing to terminate the lease agreements as permitted under the termination clause of the agreements. The remaining payments under the agreements were made in 2009 for PSNH and WMECO and January 2011 for CL&P and Yankee Gas.

CL&P entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not included in the tables above. See Note 12C, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements for further information regarding these contracts.

14.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of fixed-rate long-term debt securities and RRBs is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. Adjustable rate securities are assumed to have a fair value equal to their carrying value. Carrying amounts and estimated fair values are as follows:

	As of December 31, 2010							
	NU		**CL&P**		**PSNH**		**WMECO**	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 93.7	$ 116.2	$ 93.7	$ -	$ -	$ -	$ -

Long-Term Debt - First Mortgage Bonds	2,703.4	2,998.7	1,919.8	2,148.3	430.0	462.8	-	-
Other Long-Term Debt	1,989.0	2,045.1	667.7	668.4	407.3	408.6	401.0	417.0
Rate Reduction Bonds	181.6	193.3	-	-	138.2	146.9	43.3	46.4

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	As of December 31, 2009							
	NU		CL&P		PSNH		WMECO	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 86.8	$ 116.2	$ 86.8	$ -	$ -	$ -	$ -
Long-Term Debt -								
First Mortgage Bonds	2,657.7	2,713.5	1,919.8	1,960.6	430.0	425.4	-	-
Other Long-Term Debt	1,893.6	1,938.0	667.4	673.4	407.3	408.6	305.9	304.9
Rate Reduction Bonds	442.4	487.3	195.6	220.1	188.1	203.5	58.7	63.7

The NU Other Long-Term Debt includes $301 million and $300.6 million of fees and interest due for spent nuclear fuel disposal costs as of December 31, 2010 and 2009, respectively. CL&P's portion of this obligation is $243.8 million and $243.5 million and WMECO's portion of this obligation is $57.2 million and $57.1 million as of December 31, 2010 and 2009, respectively.

Derivative Instruments: NU, including CL&P and PSNH, holds various derivative instruments that are carried at fair value. For further information, see Note 4, "Derivative Instruments," to the consolidated financial statements.

Other Financial Instruments: Investments in marketable securities are carried at fair value on the accompanying consolidated balance sheets. For further information, see Note 1I, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 5, "Marketable Securities," to the consolidated financial statements.

The carrying value of other financial instruments included in current assets and current liabilities, including cash and cash equivalents and special deposits, approximates their fair value due to the short-term nature of these instruments.

15.

PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION (CL&P)

CL&P's charter authorizes it to issue up to 9 million shares of preferred stock ($50 par value per share) of which 2,324,000 shares were outstanding as of December 31, 2010 and 2009. In addition, CL&P's charter authorizes it to issue up to 8 million shares of Class A preferred stock ($25 par value per share). There were no Class A preferred shares outstanding as of December 31, 2010 and 2009. The issuance of additional preferred shares would be subject to approval by the DPUC.

Preferred stockholders have liquidation rights equal to the par value for each class, which they would receive in preference to any distributions to any junior stock. Were there to be a shortfall, all preferred stockholders would share ratably in available liquidation assets. Details of preferred stock not subject to mandatory redemption are as follows (in millions except in redemption price and shares):

Description	December 31, 2010 Redemption Price	Shares Outstanding as of December 31, 2010 and 2009	As of December 31, 2010	2009
$1.90 Series of 1947	$ 52.50	163,912	$ 8.2	$ 8.2
$2.00 Series of 1947	$ 54.00	336,088	16.8	16.8
$2.04 Series of 1949	$ 52.00	100,000	5.0	5.0
$2.20 Series of 1949	$ 52.50	200,000	10.0	10.0
3.90% Series of 1949	$ 50.50	160,000	8.0	8.0
$2.06 Series E of 1954	$ 51.00	200,000	10.0	10.0
$2.09 Series F of 1955	$ 51.00	100,000	5.0	5.0
4.50% Series of 1956	$ 50.75	104,000	5.2	5.2
4.96% Series of 1958	$ 50.50	100,000	5.0	5.0
4.50%	$	160,000	8.0	8.0

Series of 1963		50.50					
5.28%	$						
			200,000		10.0		10.0
Series of 1967		51.43					
$3.24	$						
			300,000		15.0		15.0
Series G of 1968		51.84					
6.56%	$						
			200,000		10.0		10.0
Series of 1968		51.44					
Totals			2,324,000	$	116.2	$	116.2

Dividends totaling $6.1 million for 2010 and $5.6 million for 2009 and 2008 were declared and dividends of $5.6 million were paid to the preferred stockholders in 2010, 2009 and 2008.

16.

ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The accumulated balance for each component of other comprehensive income/(loss), net of tax, is as follows:

(Millions of Dollars) **NU**		**December 31, 2008**		**2009 Change**		**December 31, 2009**		**2010 Change**		**December 31, 2010**
Qualified Cash Flow Hedging Instruments	$	(4.6)	$	0.2	$	(4.4)	$	0.2	$	(4.2)
Unrealized Gains/(Losses) on Other Securities		1.2		(1.0)		0.2		0.4		0.6
Pension, SERP and PBOP Benefits		(33.9)		(5.4)		(39.3)		(0.5)		(39.8)
Accumulated Other Comprehensive Income/(Loss)	$	(37.3)	$	(6.2)	$	(43.5)	$	0.1	$	(43.4)

CL&P										
Qualified Cash Flow Hedging Instruments	$	(3.6)	$	0.4	$	(3.2)	$	0.5	$	(2.7)
Unrealized Gains/(Losses) on Other Securities		-		-		-		-		-
Accumulated Other Comprehensive Income/(Loss)	$	(3.6)	$	0.4	$	(3.2)	$	0.5	$	(2.7)
PSNH										
Qualified Cash Flow Hedging Instruments	$	(0.8)	$	0.1	$	(0.7)	$	0.1	$	(0.6)
Unrealized Gains/(Losses) on Other Securities		0.1		(0.1)		-		-		-
Accumulated Other Comprehensive Income/(Loss)	$	(0.7)	$	-	$	(0.7)	$	0.1	$	(0.6)
WMECO										
Qualified Cash Flow Hedging Instruments	$	0.1	$	(0.1)	$	-	$	(0.1)	$	(0.1)
Unrealized Gains/(Losses) on Other Securities		0.1		(0.1)		-		-		-
Accumulated Other Comprehensive Income/(Loss)	$	0.2	$	(0.2)	$	-	$	(0.1)	$	(0.1)

Qualified cash flow hedging items impacting Net Income in the tables above represent amounts that were reclassified from Accumulated Other Comprehensive Income/(Loss) into Net Income in connection with the consummation of interest rate swap agreements and the amortization of existing interest rate hedges.

The changes in the components of other comprehensive income/(loss) are reported net of the following income tax effects:

(Millions of Dollars)						
NU		**2010**		**2009**		**2008**
Qualified Cash Flow Hedging Instruments	$	(0.2)	$	(0.2)	$	4.5
Change in Unrealized Gains/(Losses) on Other Securities		(0.2)		0.7		1.1
Pension, SERP and PBOP Benefits		-		2.9		24.2
Total	$	(0.4)	$	3.4	$	29.8
CL&P						
Qualified Cash Flow Hedging Instruments	$	(0.3)	$	(0.3)	$	2.2

PSNH			
Qualified Cash Flow Hedging Instruments	$ (0.1)	$ -	$ 1.0
WMECO			
Qualified Cash Flow Hedging Instruments	$ -	$ 0.1	$ 0.1

It is estimated that a charge of $0.2 million will be reclassified from Accumulated Other Comprehensive Income/(Loss) as a decrease to earnings over the next 12 months as a result of amortization of the interest rate swap agreements, which have been settled. Included in this amount are estimated charges of $0.4 million and $0.1 million for CL&P and PSNH, respectively, and a benefit of $0.1 million for WMECO. As of December 31, 2010, it is estimated that a pre-tax amount of $6 million included in the Accumulated Other Comprehensive Income/(Loss) balance will be reclassified as a decrease to Net Income over the next 12 months related to Pension, SERP and PBOP adjustments for NU.

17.

DIVIDEND RESTRICTIONS

NU parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement.

CL&P, PSNH, and WMECO are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, PSNH and WMECO, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from retained earnings. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. Such state law restrictions do not restrict payment of dividends from retained earnings or net income. CL&P, PSNH, WMECO and Yankee Gas also have a revolving credit agreement that imposes leverage restrictions including consolidated total debt to total capitalization ratio requirements. The Retained Earnings balances subject to these leverage restrictions are $1.453 billion for NU, $734.6 million for CL&P, $347.5 million for PSNH and $98.8 million for WMECO as of December 31, 2010. PSNH is further required to reserve an additional amount under its FERC hydroelectric license conditions. As of December 31, 2010, approximately $11.6 million of PSNH's Retained Earnings is subject to restriction under its FERC hydroelectric license conditions. As of December 31, 2010, NU, CL&P, PSNH, WMECO and Yankee Gas were in compliance with all such provisions of its credit agreement that may restrict the payment of dividends.

18.

COMMON SHARES

The following table sets forth the NU common shares and the shares of CL&P, PSNH and WMECO common stock authorized and issued and the respective par values as of December 31, 2010 and 2009:

			Shares		
		Per Share Par Value	Authorized	Issued	
			2010 and 2009	2010	2009
NU	$	5	225,000,000	195,781,740	195,455,214
CL&P	$	10	24,500,000	6,035,205	6,035,205
PSNH	$	1	100,000,000	301	301
WMECO	$	25	1,072,471	434,653	434,653

On March 20, 2009, NU issued approximately 19 million common shares. As of December 31, 2010 and 2009, 19,333,659 and 19,708,136 NU common shares were held as treasury shares, respectively.

19.

COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS (NU)

A summary of the changes in Common Shareholders' Equity and Noncontrolling Interests of NU is as follows:

	For the Years Ended December 31,							
	2010				2009		2008	
(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Preferred Stock Not Subject to Mandatory Redemption	Total Equity	Preferred Stock Not Subject to Mandatory Redemption	Total Equity	Preferred Stock Not Subject to Mandatory Redemption
	$	$	$	$	$	$	$	$

Balance as of Beginning of Year	3,577.9	-	3,577.9	116.2	3,020.3	116.2	2,913.8	116.2
Net Income	394.1	-	394.1	-	335.6	-	266.4	-
Dividends on Common Shares	(181.7)	-	(181.7)	-	(162.8)	-	(129.0)	-
Dividends on Preferred Stock	(6.1)	-	(6.1)	(6.1)	(5.6)	(5.6)	(5.6)	(5.6)
Issuance of Common Shares	7.4	-	7.4	-	389.7	-	5.5	-
Capital Stock Expenses, Net	(0.3)	-	(0.3)	-	(12.5)	-	0.1	-
Contributions to NPT	-	1.4	1.4	-	-	-	-	-
Other Transactions, Net	19.9	-	19.9	-	18.7	-	15.7	-
Net Income Attributable to Noncontrolling Interests	(0.1)	0.1	-	6.1	-	5.6	-	5.6
Other Comprehensive Income/(Loss) (Note 16)	0.1	-	0.1	-	(5.5)	-	(46.6)	-
Balance as of End of Year	$ 3,811.2	$ 1.5	$ 3,812.7	$ 116.2	$ 3,577.9	$ 116.2	$ 3,020.3	$ 116.2

20.

EARNINGS PER SHARE (NU)

EPS is computed based upon the monthly weighted average number of common shares outstanding, excluding unallocated ESOP shares, during each year. Diluted EPS is computed on the basis of the monthly weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. The computation of diluted EPS excludes the effect of the potential exercise of share awards when the average market price of the common shares is lower than the exercise price of the related awards during the period. These outstanding share awards are not included in the computation of diluted EPS because the effect would have been antidilutive. In 2010 and 2009, there were 1,578 and 17,637 share awards excluded from the computation, respectively, as these awards were antidilutive. In 2008, there were no antidilutive share awards outstanding.

The following table sets forth the components of basic and diluted EPS:

(Millions of Dollars, except share information)	**2010**	**2009**	**2008**
Net Income Attributable to Controlling Interests	$ 387.9	$ 330.0	$ 260.8

Weighted Average Common Shares Outstanding:						
Basic		176,636,086		172,567,928		155,531,846
Dilutive Effect		249,301		149,318		467,394
Diluted		176,885,387		172,717,246		155,999,240
Basic EPS	$	2.20	$	1.91	$	1.68
Diluted EPS	$	2.19	$	1.91	$	1.67

RSUs and performance shares are included in basic common shares outstanding as of the date that all necessary vesting conditions have been satisfied. The dilutive effect of outstanding RSUs and performance shares for which common shares have not been issued is calculated using the treasury stock method. Assumed proceeds of the units under the treasury stock method consist of the remaining compensation cost to be recognized and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the units (the difference between the market value of the average units outstanding for the year, using the average market price during the year, and the grant date market value).

The dilutive effect of stock options is also calculated using the treasury stock method. Assumed proceeds for stock options consist of remaining compensation cost to be recognized, cash proceeds that would be received upon exercise, and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the stock options (the difference between the market value of the average stock options outstanding for the year, using the average market price during the year, and the grant price).

Allocated ESOP shares are included in basic common shares outstanding in the above table.

21.

SEGMENT INFORMATION

Presentation: NU is organized between the Regulated companies' segments, NU Enterprises and Other based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income.

The Regulated companies' segments include the electric distribution segment, the natural gas distribution segment and the electric transmission segment. The electric distribution segment includes the generation activities of PSNH and WMECO. The Regulated companies' segments represented substantially all of NU's total consolidated revenues for each of the years ended December 31, 2010, 2009 and 2008.

NU Enterprises is comprised of the following: 1) Select Energy (wholesale contracts), 2) Boulos, 3) NGS, 4) NGS Mechanical, 5) SECI, and 6) NU Enterprises parent.

Other in the tables below primarily consists of 1) the results of NU parent, which includes other income related to the equity in earnings of NU parent's subsidiaries and interest income from the NU Money Pool, which are both eliminated in consolidation, and interest income and expense related to the cash and debt of NU parent, respectively, 2) the revenues and expenses of NU's service companies, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which are comprised of RRR (a real estate subsidiary), the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company and Yankee Energy Financial Services Company) and the remaining operations of HWP that were not exited as part of the sale of the competitive generation business in 2006 and the sale of its transmission business to WMECO in December 2008.

Regulated companies' revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

NU's segment information for the years ended December 31, 2010, 2009 and 2008, with the distribution segment segregated between electric and natural gas, is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	For the Year Ended December 31, 2010						
	Regulated Companies						
	Distribution						
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 3,802.0	$ 434.3	$ 625.6	$ 80.3	$ 441.3	$ (485.3)	$ 4,898.2
Depreciation and Amortization	(506.7)	(23.8)	(86.7)	(0.3)	(15.5)	3.8	(629.2)
Other Operating Expenses	(2,919.6)	(340.0)	(192.1)	(62.6)	(442.8)	488.0	(3,469.1)
Operating Income/(Loss)	375.7	70.5	346.8	17.4	(17.0)	6.5	799.9
Interest Expense	(133.4)	(17.9)	(73.2)	(2.2)	(15.2)	4.6	(237.3)
Interest Income	0.7	-	1.8	-	5.3	(6.3)	1.5
Other Income, Net	24.4	0.8	14.3	(0.3)	436.7	(435.5)	40.4
Income Tax (Expense)/Benefit	(90.3)	(20.7)	(109.3)	(6.6)	17.6	(1.1)	(210.4)
Net Income	177.1	32.7	180.4	8.3	427.4	(431.8)	394.1
Net Income Attributable to Noncontrolling Interests	(3.6)	-	(2.6)	-	-	-	(6.2)
Net Income Attributable to Controlling Interests	$ 173.5	$ 32.7	$ 177.8	$ 8.3	$ 427.4	$ (431.8)	$ 387.9
Total Assets (as of)	$ 8,968.9	$ 1,451.5	$ 3,418.3	$ 86.7	$ 6,197.9	$ (5,601.3)	$ 14,522.0
Cash Flows for Total Investments in Plant	$ 560.1	$ 82.5	$ 239.2	$ -	$ 72.7	$ -	$ 954.5

	For the Year Ended December 31, 2009						
	Regulated Companies						
	Distribution						
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 4,358.4	$ 449.6	$ 577.9	$ 81.3	$ 400.8	$ (428.6)	$ 5,439.4
Depreciation and Amortization	(431.5)	(26.8)	(71.0)	(0.4)	(13.0)	1.9	(540.8)
Other Operating Expenses	(3,604.6)	(368.1)	(170.9)	(53.8)	(382.1)	432.3	(4,147.2)
Operating Income	322.3	54.7	336.0	27.1	5.7	5.6	751.4
Interest Expense	(149.1)	(22.1)	(72.5)	(2.8)	(33.4)	6.3	(273.6)
Interest Income	4.5	-	1.0	-	7.7	(7.6)	5.6
Other Income, Net	24.0	0.3	7.6	-	371.6	(371.4)	32.1
Income Tax (Expense)/Benefit	(60.2)	(11.9)	(105.5)	(8.5)	8.6	(2.4)	(179.9)
Net Income	141.5	21.0	166.6	15.8	360.2	(369.5)	335.6
Net Income Attributable to Noncontrolling Interests	(3.3)	-	(2.3)	-	-	-	(5.6)
Net Income Attributable to Controlling Interests	$ 138.2	$ 21.0	$ 164.3	$ 15.8	$ 360.2	$ (369.5)	$ 330.0
Total Assets (as of)	$ 8,881.1	$ 1,379.0	$ 3,263.0	$ 71.9	$ 5,857.8	$ (5,395.1)	$ 14,057.7
Cash Flows for Total Investments in Plant	$ 521.5	$ 54.8	$ 286.0	$ -	$ -	$ 45.8	$ 908.1

	For the Year Ended December 31, 2008						
	Regulated Companies						
	Distribution						
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**NU Enterprises**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 4,716.1	$ 577.4	$ 424.8	$ 114.1	$ 416.6	$ (448.9)	$ 5,800.1
Depreciation and Amortization	(581.5)	(26.2)	(49.3)	(0.6)	(13.1)	0.9	(669.8)
Other Operating Expenses	(3,828.6)	(487.3)	(138.5)	(89.6)	(431.2)	435.7	(4,539.5)
Operating Income/(Loss)	306.0	63.9	237.0	23.9	(27.7)	(12.3)	590.8
Interest Expense	(164.3)	(21.6)	(51.8)	(5.6)	(35.4)	9.6	(269.1)
Interest Income	14.1	0.5	2.1	1.0	8.5	(10.6)	15.6

Other Income, Net	13.1	0.3	21.8	-	227.5	(227.9)	34.8
Income Tax (Expense)/Benefit	(41.6)	(16.0)	(68.8)	(6.2)	28.7	(1.8)	(105.7)
Net Income	127.3	27.1	140.3	13.1	201.6	(243.0)	266.4
Net Income Attributable to Noncontrolling Interests	(3.6)	-	(2.0)	-	-	-	(5.6)
Net Income Attributable to Controlling Interests	$ 123.7	$ 27.1	$ 138.3	$ 13.1	$ 201.6	$ (243.0)	$ 260.8
Cash Flows for Total Investments in Plant	$ 487.8	$ 58.4	$ 678.9	$ -	$ 30.3	$ -	$ 1,255.4

The information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the years ended December 31, 2010, 2009 and 2008 is included below. Information for segmenting total assets between electric distribution and transmission is not available as of December 31, 2008.

	CL&P - For the Years Ended December 31,								
	2010			2009			2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**
Operating Revenues	$ 2,500.3	$ 498.8	$ 2,999.1	$ 2,954.6	$ 469.9	$ 3,424.5	$ 3,218.5	$ 339.9	$ 3,558.4
Depreciation and Amortization	(355.5)	(67.6)	(423.1)	(330.3)	(58.4)	(388.7)	(433.1)	(39.4)	(472.5)
Other Operating Expenses	(1,942.4)	(146.0)	(2,088.4)	(2,441.7)	(129.0)	(2,570.7)	(2,610.5)	(102.0)	(2,712.5)
Operating Income	202.4	285.2	487.6	182.6	282.5	465.1	174.9	198.5	373.4
Interest Expense	(77.6)	(60.1)	(137.7)	(93.1)	(62.7)	(155.8)	(102.1)	(44.1)	(146.2)
Interest Income	1.9	1.5	3.4	2.7	0.8	3.5	9.2	1.6	10.8
Other Income, Net	14.6	8.6	23.2	16.2	6.1	22.3	12.4	18.7	31.1
Income Tax Expense	(43.6)	(88.8)	(132.4)	(31.1)	(87.7)	(118.8)	(20.8)	(57.1)	(77.9)
Net Income	$ 97.7	$ 146.4	$ 244.1	$ 77.3	$ 139.0	$ 216.3	$ 73.6	$ 117.6	$ 191.2
	$ 5,687.9	$ 2,599.7	$ 8,287.6	$ 5,771.1	$ 2,593.5	$ 8,364.6	$ -	$ -	$ -

Total Assets (as of)																		
Cash Flows for Total Investments in Plant	$	270.2	$	110.1	$	380.3	$	270.8	$	164.9	$	435.7	$	294.3	$	555.2	$	849.5

	PSNH - For the Years Ended December 31,								
	2010			2009			2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**
Operating Revenues	$ 951.0	$ 82.4	$ 1,033.4	$ 1,035.8	$ 73.8	$ 1,109.6	$ 1,082.2	$ 59.0	$ 1,141.2
Depreciation and Amortization	(118.4)	(10.4)	(128.8)	(70.5)	(9.3)	(79.8)	(104.0)	(7.2)	(111.2)
Other Operating Expenses	(696.0)	(32.4)	(728.4)	(865.8)	(29.4)	(895.2)	(882.8)	(24.3)	(907.1)
Operating Income	136.6	39.6	176.2	99.5	35.1	134.6	95.4	27.5	122.9
Interest Expense	(38.6)	(8.5)	(47.1)	(39.8)	(6.7)	(46.5)	(44.6)	(5.6)	(50.2)
Interest Income/(Loss)	(1.7)	0.2	(1.5)	2.1	0.1	2.2	2.9	0.5	3.4
Other Income, Net	11.6	1.7	13.3	6.0	1.3	7.3	1.4	2.6	4.0
Income Tax Expense	(38.6)	(12.2)	(50.8)	(20.2)	(11.8)	(32.0)	(13.7)	(8.3)	(22.0)
Net Income	$ 69.3	$ 20.8	$ 90.1	$ 47.6	$ 18.0	$ 65.6	$ 41.4	$ 16.7	$ 58.1
Total Assets (as of)	$ 2,399.3	$ 490.5	$ 2,889.8	$ 2,255.0	$ 442.2	$ 2,697.2	$ -	$ -	$ -
Cash Flows for Total Investments in Plant	$ 252.2	$ 44.1	$ 296.3	$ 207.8	$ 58.6	$ 266.4	$ 158.6	$ 80.3	$ 238.9

	WMECO - For the Years Ended December 31,								
	2010			2009			2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**	**Distribution**	**Transmission**	**Totals**
Operating Revenues	$ 350.9	$ 44.3	$ 395.2	$ 368.2	$ 34.2	$ 402.4	$ 415.6	$ 25.9	$ 441.5
Depreciation and Amortization	(32.9)	(8.6)	(41.5)	(30.8)	(3.2)	(34.0)	(44.4)	(2.7)	(47.1)

Other Operating Expenses	(281.3)	(13.8)	(295.1)	(297.3)	(12.5)	(309.8)	(335.5)	(12.4)	(347.9)
Operating Income	36.7	21.9	58.6	40.1	18.5	58.6	35.7	10.8	46.5
Interest Expense	(17.1)	(4.7)	(21.8)	(16.1)	(3.2)	(19.3)	(17.5)	(2.1)	(19.6)
Interest Income	0.4	0.2	0.6	(0.3)	-	(0.3)	1.9	0.1	2.0
Other Income, Net	(1.8)	3.8	2.0	1.8	0.3	2.1	(0.7)	0.6	(0.1)
Income Tax Expense	(8.1)	(8.2)	(16.3)	(8.8)	(6.1)	(14.9)	(7.1)	(3.4)	(10.5)
Net Income	$ 10.1	$ 13.0	$ 23.1	$ 16.7	$ 9.5	$ 26.2	$ 12.3	$ 6.0	$ 18.3
Total Assets (as of)	$ 884.2	$ 315.4	$ 1,199.6	$ 863.2	$ 238.6	$ 1,101.8	$ -	$ -	$ -
Cash Flows for Total Investments in Plant	$ 37.6	$ 77.6	$ 115.2	$ 42.9	$ 62.5	$ 105.4	$ 34.9	$ 43.4	$ 78.3

22.

SUBSEQUENT EVENT (WMECO)

On January 31, 2011, the DPU issued a final decision on WMECO's distribution rate case 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, and recovery of certain 2008 and 2010 major storm costs over five years and recovery of certain hardship costs. The DPU did not approve WMECO s request for rate recovery of increased reliability infrastructure investment averaging approximately $20 million per year.

The decision clarified which customer hardship balances should be recovered through rates, which resulted in an increase to WMECO s uncollectible accounts receivable reserves and bad debt expense, both of which have been reflected on the accompanying consolidated financial statements. The decision also disallowed recovery of certain previously deferred rate case filing costs and allowed recovery of an additional amount not previously deferred for 2010 tax benefits lost as a result of the 2010 Health Care Act; these amounts were recorded in Net Income, with offsets to Regulatory Assets, both of which have also been reflected on the accompanying consolidated financial statements. For the year ended December 31, 2010, the net effect of these impacts was a pre-tax charge of approximately $1.8 million.

23.

QUARTERLY FINANCIAL DATA (UNAUDITED)

NU Consolidated Statements of Quarterly Financial Data *(Millions of Dollars, except per share information)*	**Quarter Ended (a)**			
	March 31,	**June 30,**	**September 30,**	**December 31,**
2010				
Operating Revenues	$ 1,339.4	$ 1,111.4	$ 1,243.3	$ 1,204.1
Operating Income	226.7	178.3	199.6	195.3
Net Income	87.6	73.3	101.9	131.3
Net Income Attributable to Controlling Interests	86.2	71.9	100.5	129.3
Basic and Diluted Earnings Per Common Share	$ 0.49	$ 0.41	$ 0.57	$ 0.73
2009				
Operating Revenues	$ 1,593.5	$ 1,224.4	$ 1,306.2	$ 1,315.3
Operating Income	217.3	179.2	162.5	192.4
Net Income	99.1	84.2	66.2	86.1
Net Income Attributable to Controlling Interests	97.7	82.9	64.8	84.7
Basic and Diluted Earnings Per Common Share	$ 0.60	$ 0.47	$ 0.37	$ 0.48

(a)

The summation of quarterly EPS data may not equal annual data due to rounding.

CL&P Consolidated Statements of Quarterly Financial Data	**Quarter Ended**			
(Millions of Dollars)	**March 31,**	**June 30,**	**September 30,**	**December 31,**
2010				
Operating Revenues	$ 795.0	$ 707.9	$ 789.2	$ 707.0
Operating Income	125.5	106.2	131.4	124.6
Net Income	48.4	44.1	69.0	82.6
2009				
Operating Revenues	$ 954.5	$ 784.9	$ 859.3	$ 825.8
Operating Income	115.4	118.1	110.1	121.6
Net Income	53.1	58.4	46.5	58.2

PSNH Consolidated Statements of Quarterly Financial Data	**Quarter Ended**			
(Millions of Dollars)	**March 31,**	**June 30,**	**September 30,**	**December 31,**
2010				
Operating Revenues	$ 258.6	$ 238.3	$ 277.0	$ 259.5
Operating Income	39.9	43.4	49.8	43.1
Net Income	15.8	21.6	28.8	23.9
2009				
Operating Revenues	$ 307.7	$ 262.9	$ 275.1	$ 263.9
Operating Income	36.1	31.2	34.1	33.2
Net Income	17.5	16.6	16.2	15.3

WMECO Consolidated Statements of Quarterly Financial Data	**Quarter Ended**			
(Millions of Dollars)	**March 31,**	**June 30,**	**September 30,**	**December 31,**
2010				
Operating Revenues	$ 100.2	$ 92.5	$ 103.7	$ 98.8
Operating Income	16.4	14.3	14.9	13.1
Net Income	5.7	5.2	7.3	4.9
2009				
Operating Revenues	$ 118.1	$ 95.1	$ 96.6	$ 92.6
Operating Income	15.3	13.2	17.1	13.0
Net Income	6.1	5.8	8.5	5.7

Item 8A.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

No events that would be described in response to this item have occurred with respect to NU, CL&P, PSNH or WMECO.

Item 8B.

Controls and Procedures

Management, on behalf of NU, CL&P, PSNH and WMECO, is responsible for the preparation, integrity, and fair presentation of the accompanying Consolidated Financial Statements and other sections of this combined Annual Report on Form 10-K. NU, CL&P, PSNH and WMECO s internal controls over financial reporting were audited by Deloitte & Touche LLP.

Management, on behalf of NU, CL&P, PSNH and WMECO, is responsible for establishing and maintaining adequate internal controls over financial reporting. The internal control framework and processes have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment. Under the supervision and with the participation of the principal executive officers and principal financial officer, an evaluation of the effectiveness of internal controls over financial reporting was conducted based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that internal controls over financial reporting at NU, CL&P, PSNH and WMECO were effective as of December 31, 2010.

Management, on behalf of NU, CL&P, PSNH and WMECO, undertook a separate evaluation of the design and operation of disclosure controls and procedures to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Securities Exchange Act of 1934 and the rules and forms of the SEC. This evaluation was made under management s supervision and with management s participation, including the principal executive officers and principal financial officer, as of the end of the period covered by this report on Form 10-K. The principal executive officers and principal financial officer have concluded, based on their review, that the disclosure controls and procedures of NU, CL&P, PSNH and WMECO are effective to ensure that information required to be disclosed by us in reports filed under the Securities Exchange Act of 1934 i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and ii) is accumulated and communicated to management, including the principal executive officers and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no changes in internal controls over financial reporting for NU, CL&P, PSNH and WMECO during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Item 9.

Other Information

No information is required to be disclosed under this item as of December 31, 2010, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2010.

PART III

Item 10.

Directors, Executive Officers and Corporate Governance

The information in Item 10 is provided as of February 24, 2011 except where otherwise indicated.

Certain information required by this Item 10 is omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly Owned Subsidiaries.

NU

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information to be contained in the sections captioned "Election of Trustees," "Governance of Northeast Utilities" and the related subsections, "Selection of Trustees," and "Section 16(a) Beneficial Ownership Reporting Compliance" of NU's definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 30, 2011.

NU and CL&P

The following table sets forth certain information as of February 24, 2011 concerning NU s and CL&P s executive officers:

Name	Age	Title
Jay S. Buth	41	Vice President - Accounting and Controller of NU and CL&P.
Gregory B. Butler	53	Senior Vice President and General Counsel of NU and CL&P.
Jeffrey D. Butler*	55	President and Chief Operating Officer of CL&P
Jean M. LaVecchia**	59	Vice President - Human Resources of NUSCO.
David R. McHale	50	Executive Vice President and Chief Financial Officer of NU and CL&P.

Leon J. Olivier	62	Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of CL&P.
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; Chairman of CL&P.

*

Mr. Butler is President and Chief Operating Officer and Director of CL&P and is therefore an executive officer solely of CL&P.

**

Deemed executive officer of NU and CL&P 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.

Jeffrey D. Butler. Mr. Butler was elected President and Chief Operating Officer and a Director of CL&P effective July 1, 2009. Previously, Mr. Butler was employed by Pacific Gas & Electric Company for approximately 28 years, most recently as Senior Vice President - Energy Delivery, before retiring in March 2008. Prior to his last assignment, Mr. Butler also held the positions of Senior Vice President - Transmission and Distribution, Vice President - Operations, Maintenance and Construction, and Vice President - Distribution Operations, Maintenance and Construction beginning in July 1997.

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, WMECO and PSNH, 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, WMECO and PSNH 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.

There are no family relationships between any director or executive officer and any other trustee, director or executive officer of NU or CL&P and none of the above executive officers or directors serves as an executive officer or director pursuant to any agreement or understanding with any other person. Our executive officers hold the offices set forth opposite their names until the next annual meeting of the Board of Trustees, in the case of NU, and the Board of Directors, in the case of CL&P, and until their successors have been elected and qualified.

CL&P obtains audit services from the independent registered public accounting firm engaged by the Audit Committee of NU's Board of Trustees. CL&P does not have its own audit committee or, accordingly, an audit committee financial expert. CL&P relies on NU, which has an audit committee and an audit committee expert.

CODE OF ETHICS AND STANDARDS OF BUSINESS CONDUCT

Each of NU, CL&P, PSNH and WMECO has adopted a Code of Ethics for Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) and the Standards of Business Conduct, which are applicable to all Trustees, directors, officers, employees, contractors and agents of NU, CL&P, PSNH and WMECO. The Code of Ethics and the Standards of Business Conduct have both been posted on the NU web site and are available at www.nu.com/investors/corporate_gov/default.asp on the Internet. Any amendments to or waivers from the Code of Ethics and Standards of Business Conduct for executive officers, directors or Trustees will be posted on the website. Any such amendment or waiver would require the prior consent of the Board of Trustees or an applicable committee thereof.

Printed copies of the Code of Ethics and the Standards of Business Conduct are also available to any shareholder without charge upon written request mailed to:

Ms. O. Kay Comendul

Assistant Secretary

Northeast Utilities Service Company

P.O. Box 270

Hartford, CT 06141

Item 11.

Executive Compensation

NU

The information required by this Item 11 for NU is incorporated herein by reference to certain information contained in NU s definitive proxy statement for solicitation of proxies, which is expected to be filed with the SEC on or about March 30, 2011, under the sections captioned "Compensation Discussion and Analysis" plus the related subsections, and "Compensation Committee Report" plus the related subsections following such Report.

PSNH and WMECO

Certain information required by this Item 11 has been omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

CL&P

The information in this Item 11 relates solely to CL&P.

COMPENSATION DISCUSSION AND ANALYSIS

OVERALL OBJECTIVES OF EXECUTIVE COMPENSATION PROGRAM

General

CL&P is a wholly-owned subsidiary of NU with a board of directors made up entirely of executive officers of NU system companies. CL&P does not have a compensation committee, and the Compensation Committee of NU s Board of Trustees determines compensation for the executive officers of CL&P, including their salaries, annual incentive awards and long-term incentive awards. All of CL&P s "Named Executive Officers," as defined below, also serve as officers of NU and one or more other subsidiaries of NU. Compensation set by the Compensation Committee of NU and set forth herein is for services rendered to NU and its subsidiaries by such officers in all capacities.

The fundamental objective of NU s Executive Compensation Program is to motivate executives and key employees to support NU s strategy of investing in and operating businesses that benefit customers, employees, and shareholders. We are also responsible to our franchise customers to provide energy services reliably, safely, with respect for the environment and our employees, and at a reasonable cost.

NU s Executive Compensation Program supports its fundamental objective through the following design principles:

·

Attract and retain key executives by providing total compensation competitive with that of other executives employed by companies of similar size and complexity in the utility and general industries. The program relies on compensation data obtained from consultants surveys of companies and from a customized peer group to ensure that compensation opportunities are competitive and capable of attracting and retaining executives with the experience and talent required to achieve NU s strategic objectives. As NU continues to grow and improve its transmission, distribution, and generation systems, having the right talent will be critical.

·

Establish performance-based compensation that balances rewards for short-term and long-term business results. The program motivates executives to run the business well in the short term, while executing the long-term business plan to benefit both NU s customers and NU shareholders. The program aims to strike a balance between the short- and long-term programs so that they work in tandem. It also ensures that long-term objectives are not sacrificed to achieve short-term goals or vice versa.

Incentive plan performance criteria are based on a combination of financial, operational, stewardship, and strategic goals that are essential to the achievement of NU s business strategies. This linkage to critical goals helps to align executives with NU s key stakeholders: customers, employees, and shareholders. The long-term program also compares performance relative to a group of comparable utility companies.

·

Reward corporate and individual performance. Overall compensation has many metrics based on NU corporate performance but is also highly differentiated based on individual performance. The annual incentive program rewards both NU corporate performance (measured by NU adjusted net income) and individual performance (including individualized financial, operational, stewardship and strategic metrics). Long-term incentives consist of performance units (performance shares and performance cash) and restricted share units (RSUs). Performance units are paid out based on the achievement of NU corporate goals (cumulative net income, average return on equity, average credit rating and relative total shareholder return). The size of RSU grants may reflect corporate performance during the preceding fiscal year as well as individual performance and contribution, but the ultimate value of the RSUs is based on total NU shareholder return.

·

Encourage long-term commitment to NU. Utility companies provide a public service and have a long-term commitment to ensure that customers receive reliable service day after day. Meeting this commitment requires specialized skills and institutional knowledge that are learned over time through local industry experience. These skills include familiarity with the regions and communities that we serve, government regulations, and long-term energy policies. In addition, utility companies rely on long-term capital investments to serve their customers.

As a result, public utilities benefit from long-term service employees. NU has structured its executive compensation programs to build long-term commitment as well as shareholder alignment. Providing competitive compensation opportunities and offering programs such as RSUs and supplemental retirement benefits that vest and have the ability to increase in value over time encourage long-term employment. Executive share ownership guidelines are another program component intended to build long-term shareholder alignment and commitment.

NAMED EXECUTIVE OFFICERS

The executive officers of CL&P listed in the Summary Compensation Table in this Item 11 whose compensation is discussed in this Compensation Discussion and Analysis (CD&A) are CL&P s Chief Executive Officer (CEO), Executive Vice President and Chief Financial Officer (CFO), and the three other most highly compensated executive officers other than CL&P s CEO and CFO who were serving as executive officers at the end of 2010 (collectively, referred to as the "Named Executive Officers" or "NEOs"). Each Named Executive Officer of CL&P also serves as an executive officer of NU and one or more other subsidiaries of NU. Compensation for such

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NEOs discussed in this CD&A was for all services provided by such individuals in all capacities to NU and its subsidiaries. For 2010, CL&P s Named Executive Officers are:

.

Leon J. Olivier, Chief Executive Officer of CL&P

.

David R. McHale, Executive Vice President and Chief Financial Officer

.

Charles W. Shivery, Chairman of the Board, President and Chief Executive Officer of NU, and Chairman of CL&P

.

Gregory B. Butler, Senior Vice President and General Counsel

.

James B. Robb, Senior Vice President-Enterprise Planning and Development of NUSCO

RISK ANALYSIS OF EXECUTIVE COMPENSATION PROGRAM

The overall compensation program features a mix of compensation elements ranging from a fixed base salary that is risk-neutral to annual and long-term incentive compensation programs intended to motivate officers and eligible employees to achieve individual and corporate performance goals that reflect the appropriate assessment of risk. The fundamental objective of the compensation program is to foster the continued growth and success of NU s business. The design and implementation of the overall compensation program provides NU s Compensation Committee with opportunities throughout the year to assess risks within the compensation program that may have a material effect on NU and its shareholders.

Each year, as part of its annual planning process, NU s Board of Trustees and its Finance Committee review NU s comprehensive annual operating and five-year strategic plans. The annual operating plan consists of the goals and objectives for the year, key performance indicators and financial forecasts. The strategic plan consists of long-term corporate goals and objectives, specific strategies to achieve those goals, and action plans designed to implement each strategy. The Enterprise Risk Management (ERM) process is integrated into the annual operating planning and the strategic planning processes. The most significant enterprise-wide financial risks are identified during development of the annual operating plans, and are updated and presented monthly to NU s Finance Committee. Enterprise strategic risks are identified and presented to the Board during development of the five-year strategic plans. Following review and approval of the annual operating and strategic plans by the Board of Trustees and the Finance Committee, the Compensation Committee reviews the overall compensation program in the context of both plans. In particular, the Compensation Committee designs the annual and long-term incentive compensation programs for officers and eligible employees to promote the achievement of the goals and objectives of the annual operating plan and the strategic plan that were each previously subjected to ERM review.

In 2009, the Compensation Committee assessed the risks associated with the executive compensation program proposed for 2010 by specifically reviewing the various elements of the incentive compensation programs. The annual incentive program was reviewed to ensure an appropriate balance between the individual and corporate goals and that the goals were appropriate to support the annual business plan. Similarly, the long-term incentive program was reviewed to ensure that the performance metrics were properly weighted and supported NU s strategic plan. Both the annual and long-term incentive programs were reviewed to ensure that mechanisms exist to mitigate risk, which mechanisms include goal setting and discretion with respect to actual payments, share ownership guidelines, clawback of incentive compensation under certain circumstances, and deferral of certain long-term incentive awards. Key elements of the executive compensation program have not changed since the review in 2009.

ELEMENTS OF 2010 COMPENSATION

Set forth below is a brief description and the objective of each material element of NU s executive compensation program:

Compensation Element	Description	Objective
Base Salary	Fixed compensation	Compensate officers for fulfilling their basic job responsibilities
	Subject to increase annually during the first quarter based on individual performance, competitive market levels, strategic importance of the role and experience in the position	Provide base pay commensurate with salaries paid to executive officers holding comparable positions in other utility companies and companies in general industry
		Aid in attracting and retaining qualified personnel

Annual Incentive Program	Variable compensation based on performance against pre-established annual NU corporate and individual goals that is paid in cash in the first quarter following the end of the program year	Promote the achievement of annual performance objectives that represent business success for the company, the executive, and his or her business unit or function

Long-Term Incentive Program	Variable compensation consisting of 25% RSUs and 75% Performance Units (see below)	
· Restricted share units (RSUs)	Common share units, which vest over a three-year period, may be granted based on NU corporate performance and individual performance and contribution	Align executive and shareholder interests through NU share performance and NU share ownership Encourage a long-term commitment to the company
· Performance units	Long-term incentive, one-half of which is performance cash and one-half of which is performance shares, that rewards individuals for NU corporate performance over a three-year period based on achieving pre-established levels of: · NU Cumulative net income · NU Average return on equity · NU Average credit rating · Total NU shareholder return relative to a group of comparable utility companies	Reward performance on key corporate priorities that are also key drivers of total NU shareholder return performance Align executive and shareholder interests through NU share performance and NU share ownership Strengthen the link between long-term compensation and total shareholder return performance Encourage long-term thinking and commitment to the company
Supplemental Benefits	Supplemental Executive Retirement Plan, Nonqualified Deferred Compensation, and Perquisites	Supplemental benefits intended to help NU attract and retain executive officers critical to NU s success by reflecting

		competitive practices
·	·	Compensate for Internal Revenue Code limits on qualified plans
Supplemental Executive Retirement Plan (Supplemental Plan)	Non-qualified pension plan, providing additional retirement income to officers beyond payments provided in NU s standard defined benefit retirement plan, consisting of: · A defined benefit "make-whole" plan · A supplemental "target" benefit (certain senior vice presidents and above only) · Executives hired after 2005 are ineligible for these benefits	Aid in retention of executives and enhance long-term commitment to the company
· Other Nonqualified Deferred Compensation (Deferral Plan)	Opportunity to defer base salary and annual incentives, using the same investment vehicles as NU s 401(k) plan, and receive matching contributions otherwise capped by Internal Revenue Code limits on qualified plans	Aid executives in tax planning by allowing them to defer taxes on certain compensation Compensate for Internal Revenue Code limits on qualified plans
	Each year s matching contribution vests after three years or at retirement	Provide a competitive benefit
	For executives hired after 2005, who are ineligible to participate in NU s defined benefit pension plan, NU makes contributions of 2.5%, 4.5% and 6.5%, as applicable based on the relevant bracket for the sum of the officer s age and years of service, of cash compensation that would otherwise be capped by Internal Revenue Code limits on qualified plans	Aid in retention and enhance long-term commitment to the company

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· Med-Vantage Plan	For executives hired after 2005, who are ineligible to participate in NU s defined benefit pension plan, starting at age 40 NU makes contributions of $1,000 per year to a qualified retiree medical savings account.	Designed to help build tax-free savings for post-employment health care expenses.
· Perquisites	Tax preparation and financial planning reimbursement benefit (certain senior executives)	Encourage use of a professional tax advisor to properly prepare complex tax returns and leverage the value of NU s compensation programs
	Executive physical examination reimbursement plan	Encourage executives to undergo regular health checks to reduce the risk of losing critical employees
	Reimbursement of relocation expenses for newly hired and transferred executives	Discretionary benefits intended to help NU s executive officers be more productive and efficient
	Reimbursement of spousal travel expenses only for business purposes	
Employment Agreements	Employment or other agreements with certain of our Named Executive Officers provide benefits and payments upon involuntary termination and termination following a change of control. Mr. Olivier participates in a "Special Severance Program" (SSP) that provides other benefits and payments upon termination of employment resulting from a change-in-control	Meet competitive expectation of employment Help focus executive on shareholder interests Provide income protection in the event of involuntary loss of employment

MIX OF COMPENSATION ELEMENTS

NU strives to provide executive officers with base salary, performance-based annual incentive compensation and long-term incentive compensation opportunities that are competitive with the market. The Compensation Committee of NU s Board of Trustees determines the Total Direct Compensation for our Named Executive Officers as described under the caption entitled "Market Analysis," below. As a result, the annual and long-term incentive target percentages for the NEOs listed in the Summary Compensation Table are approximately equal to competitive median incentives.

With respect to incentive compensation, the Compensation Committee believes it is important to balance short-term goals, such as generating earnings, with longer term goals, such as long-term value creation and maintaining a strong balance sheet. As our executive officers are promoted to more senior positions, they assume increased responsibility for implementing NU s long-term business plans and strategies, and a greater proportion of their total compensation is based on performance with a long-term focus.

The Compensation Committee determines the compensation for each executive officer based on the relative authority, duties and responsibilities of each office. Mr. Shivery s responsibilities for the daily operations and management of the Northeast Utilities System companies, as Chairman, President and Chief Executive Officer of NU and Chairman of each of the Regulated companies, are significantly greater than the duties and responsibilities of our other executive officers. As a result, Mr. Shivery s compensation is significantly higher than the compensation of our other executive officers. NU regularly reviews market compensation data for executive officer positions similar to those held by our executive officers, including Mr. Shivery, and this market data continues to indicate that chief executive officers are typically paid significantly more than other executive officers. For 2010, target annual incentive and long-term incentive compensation opportunities for Mr. Shivery were 100 percent and 300 percent of base salary, respectively. For the remaining NEOs, target annual incentive compensation opportunities ranged from 50 percent to 65 percent of base salary and target long-term incentive compensation opportunities ranged from 100 percent to 150 percent of base salary.

The following table sets forth the contribution to 2010 Total Direct Compensation (TDC) of each element of compensation, at target, reflected as a percentage of TDC, for each Named Executive Officer.

	Percentage of TDC at Target				
		Performance Based (1)			
			Long-Term Incentives (2)		
Named Executive Officer	**Base Salary**	**Annual Incentive**	**Performance Units**	**RSUs (3)**	**TDC**
Leon J. Olivier, CEO, CL&P	32%	20%	36%	12%	100%
David R. McHale	32%	20%	36%	12%	100%
Charles W. Shivery	20%	20%	45%	15%	100%
Gregory B. Butler	32%	20%	36%	12%	100%
James B. Robb	40%	20%	30%	10%	100%

(1)

The annual incentive compensation element and performance units under the long-term incentive compensation element are performance-based.

(2)

Long-term incentive compensation at target consists of 75 percent performance units and 25 percent RSUs.

(3)

RSUs vest over three years contingent upon continued employment.

MARKET ANALYSIS

The Compensation Committee strives to provide our executive officers with compensation opportunities over time at or above the median compensation levels for executive officers of companies comparable to NU. The Committee determined executive officer TDC levels in two steps. First, the Committee determined the "market" values of executive officer compensation elements (base salaries, annual incentives and long-term incentives) as well as total compensation using compensation data obtained from other companies. The Committee reviewed compensation data obtained primarily from utility and general industry surveys and, secondarily, from a customized group of peer utility companies. The Committee then reviewed the compensation elements for each executive officer with respect to the median of these market values, and considered individual performance, experience and internal pay equity to determine the amount, if any, by which the various compensation elements should differ from median market values. Significantly, the Committee has not made an explicit commitment to compensate our executive officers through a firm and direct connection between the compensation paid by NU and the compensation paid by any of the companies in the utility and general industry surveys or in the customized group of peer utilities.

Set forth below is a description of the sources of the compensation data used by the Compensation Committee when reviewing 2010 compensation:

- **Utility and general industry survey data**. The Committee analyzed compensation information obtained from surveys of diverse groups of utility and general industry companies that represent NU s market for executive officer talent. The Committee used size-adjusted utility and general industry survey data to determine base salaries and incentive opportunities. Then the Committee compared utility-specific executive officer positions, including NU s Executive Vice President and Chief Operating Officer, to utility-specific market values. For executive officer positions that have counterparts in general industry, including NU s CEO; Executive Vice President and Chief Financial Officer; Senior Vice President and General Counsel; and Senior Vice President-Enterprise Planning and Development, the Committee averaged general industry comparisons with utility industry comparisons weighted equally, as both groups represent the talent market for these executive officers.

- **Customized peer group data.** The Committee also evaluated compensation data obtained from reviews of proxy statements from NU s customized group of peer utility companies. Periodically, the Committee assesses the composition of NU s customized peer group to ensure that the number of companies is sufficient and the companies have reasonably similar revenues. The Committee reviewed the composition of NU s customized peer group in 2010 and compared the group against NU s size guidelines of revenues between approximately $3 billion and $12 billion. Keeping in mind the Compensation Committee s desire to maintain a consistent set of peer companies from year to year to avoid volatility in competitive compensation findings used for comparison across companies, the Committee maintained the same peer group for 2010 that it used in 2009. As a result, in support of executive pay decisions during 2009, NU s customized peer group consisted of utilities with annual revenues that ranged from $1.7 billion to $14 billion with median annual revenues of $6.1 billion. NU will continue to monitor their size to determine if they should be removed from the peer group in the future. The Committee considered data only for those executive officer positions where there is a title match, which in 2010 included the holding company CEO, Chief Operating Officer, Chief Financial Officer, and General Counsel. For 2010, the peer group consisted of the following 20 companies:

Allegheny Energy, Inc.	Great Plains Energy, Incorporated	Pinnacle West Capital Corporation
Alliant Energy Corporation	Integrys Energy Group, Inc.	Progress Energy, Inc.
Ameren Corporation	NiSource Inc.	SCANA Corporation
CenterPoint Energy, Inc.	NSTAR	TECO Energy, Inc.
CMS Energy Corporation	NV Energy, Inc.	Wisconsin Energy Corporation
Consolidated Edison, Inc.	OGE Energy Corp.	Xcel Energy Inc.
DTE Energy Company	Pepco Holdings, Inc.	

The Committee used compensation data obtained from these companies for insights into incentive compensation design practices and compensation levels, although no specific actions were taken in 2010 directly as a result of this information. In 2010, the Committee also used this group for performance comparisons under the 2010 2012 Long-Term Incentive Program. The Committee periodically adjusts the target percentages of annual and long-term incentives based on the survey data to ensure that they continue to represent market median levels. Adjustments are made gradually over time to avoid radical changes.

The Compensation Committee also sets supplemental benefits at levels that provide market-based compensation opportunities to the executive officers. Compensation includes perquisites to the extent they serve business purposes. The Committee periodically reviews the general market for supplemental benefits and perquisites using utility and general industry survey data, sometimes including data obtained from companies in the customized peer group. Benefits are adjusted occasionally to help maintain market parity. When the market trend for supplemental benefits reflects a general reduction (*e.g.*, the elimination of defined benefit pension plans), the Committee has reduced these benefits only for newly hired officers. The Committee reviewed NU s supplemental retirement practices most recently in 2005 and 2006, as described in more detail below under the caption entitled "Supplemental Benefits."

BASE SALARY

The Compensation Committee reviews executive officers base salaries annually. The Committee considers the following specific factors when setting or adjusting base salaries:

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Annual individual performance appraisals

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Market pay movement across industries (determined through market analysis)

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Targeted market pay positioning for each executive officer

.

Individual experience and years of service

.

Changes in corporate focus with respect to strategic importance of a position

.

Internal equity

Individuals who are performing well in strategic positions are likely to have their base salaries increased more significantly than other individuals. From time-to-time, economic conditions and corporate performance has caused salary increases to be postponed. The Committee prefers to reflect subpar corporate performance through the variable pay components.

In 2010, given the continuing uncertainty in the capital markets and weakened economic conditions, the Committee determined to continue to the base salary freeze for the NEOs, first implemented in 2009.

INCENTIVE COMPENSATION

The annual incentive program and the long-term incentive program are provided under the Northeast Utilities Incentive Plan, which was approved by NU s shareholders at its 2007 Annual Meeting of Shareholders. The annual incentive program provides cash compensation intended to reward performance under NU s annual operating plans. The long-term incentive program is designed to reward demonstrated performance and leadership, motivate future superior performance, align the interests of the executive officers with those of NU s shareholders and retain the executive officers during the term of grants. The annual and long-term programs are intended to work in tandem so that achievement of NU s annual goals leads NU towards attainment of its long-term financial goals. Similar to 2009, grants under the long-term incentive program consisted of three elements of compensation: RSUs, performance cash, and performance shares. For the 2010 2012 Long-Term Incentive Program, the grant value consisted of 25 percent RSUs, 37.5 percent performance shares, and 37.5 percent performance cash, reflecting the Committee s desire to balance the roles of total NU shareholder return and NU s corporate financial performance in its compensation programs.

Incentive grants are based on objective financial performance goals established by the Compensation Committee with the advice of the Finance Committee. The Compensation Committee sets the performance goals annually for new annual incentive and long-term incentive program performance periods, depending on NU s business focus for the then-current year and the long-term strategic plan.

2010 ANNUAL INCENTIVE PROGRAM

The 2010 Annual Incentive Program consisted of an NU corporate goal plus individual goals for each NEO. The Compensation Committee set the annual incentive compensation targets for 2010 at 100 percent of base salary for Mr. Shivery, and at 50 percent to 65 percent of base salary for the other NEOs. The annual incentive compensation targets are used as guidelines for the determination of annual incentive payments, but actual annual incentive payments may vary significantly from these targets, depending on individual and NU corporate performance. Actual annual incentive payments may equal up to two times target if NU achieves superior financial and operational results. The opportunity to earn up to two times the incentive target reflects the Compensation Committee s belief that executive officers have significant ability to affect performance outcomes. However, NU does not pay annual incentive awards if minimum levels of financial performance are not met. A total of 33 NU system company officers, including CL&P s NEOs, participated in the 2010 Annual Incentive Program.

2010 Corporate Goal

The objective of the 2010 Annual Incentive Program corporate goal for the NEOs was to achieve an NU adjusted net income (ANI) target established by the Compensation Committee. ANI is defined as consolidated Northeast Utilities net income adjusted to exclude the effect of certain nonrecurring income and expense items or events. The Committee uses ANI because it believes that ANI serves as an indicator of ongoing operating performance. The minimum payout under the corporate goal was set at 50 percent of target and would have occurred if actual ANI had been at least 90 percent of the ANI target. The maximum payout under the corporate goal was set at 200 percent of target and would have occurred if actual ANI had been at least 110 percent of the ANI target.

For 2010, the Compensation Committee established the ANI target at $346.8 million. The ANI target reflects the midpoint of the range of internal ANI estimates calculated at the beginning of the year. The ANI thresholds for the individual and corporate goals appear below (dollars in millions):

Threshold for Individual Goals (20% below ANI Target)	**Minimum Corporate Goal (10% Below ANI Target)**	**2010 ANI Target**	**Maximum Corporate Goal (10% Above ANI Target)**	**Actual 2010 ANI**
$ 277.4	$ 312.1	$ 346.8	$ 381.5	$ 400.6

The Compensation Committee set the ANI threshold for achieving individual goals and the minimum and maximum corporate goals in its discretion based on the following factors:

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An assessment of the potential volatility in results through an evaluation of critical elements of the strategic business plan, both individually and in combination with each other;

.

The degree of difficulty in achieving the ANI target; and

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The minimum acceptable ANI.

At the time that the Compensation Committee established the performance goals for 2010, the Committee also considered and agreed upon exclusions from ANI consisting of certain nonrecurring income and expense items or events that were either beyond the control of management generally or related to a decision by the Committee not to penalize executive officers for making correct strategic business decisions. The Compensation Committee approved all final exclusions from ANI. In addition, using its discretion, the Compensation Committee excluded the positive effect on earnings that resulted from the delay of a planned asset transaction. The income and expense items set forth below were excluded from ANI in 2010.

<u>Excluded Categories</u>	**Specific 2010 Adjustments *($ in millions)***
Changes to net income as the result of accounting or tax law changes	$ (5.1)
Delay in planned asset transactions	$ 1.8
Incremental NSTAR merger costs	$ (9.4)
Net Adjustments:	$ (12.7)

2010 Individual Goals

The 2010 Annual Incentive Program individual goals included various financial, operational, stewardship, and strategic metrics that are drivers of overall corporate performance. The achievement of individual goals would result in an annual incentive payment only if actual ANI is at least 80 percent of the ANI target. Upon achieving this ANI threshold, the maximum payout is possible for individual goals for every participant.

This 80 percent ANI threshold satisfies the requirements of Section 162(m) of the Internal Revenue Code. The Committee acts in its discretion under Section 162(m) and related Internal Revenue Service rules and regulations to ensure that incentive compensation payments are "qualified performance based compensation" not subject to the $1 million limitation on deductibility.

The Compensation Committee, acting jointly with NU s Corporate Governance Committee, determines Mr. Shivery s proposed annual incentive program payment based on the extent to which individual and corporate goals have been achieved. The Compensation Committee recommends to NU s Board of Trustees for approval the proposed award for Mr. Shivery. For the remaining NEOs, Mr. Shivery recommends annual incentive awards to the Compensation Committee for its approval. NEOs are eligible to receive up to two times the annual incentive compensation target for the individual portion of the award.

Goal Weightings and Individual Goals for 2010

The following table sets forth the weighting of the annual incentive program corporate goal and individual goals of each NEO s compensation for 2010. These weightings reflect the Compensation Committee s desire to balance individual accountability with teamwork across NU s organization. Individual goals for our NEOs range from 40 percent to 50 percent of the total annual incentive program target. Certain of our NEOs individual performance goals are subjective in nature and cannot be measured either by reference to existing financial metrics or by using pre-determined mathematical formulas. The Committee believes that it is important to exercise judgment and discretion when determining the extent to which each NEO satisfies subjective individual performance goals. The Committee considers these goals along with several factors, including overall individual performance, corporate performance, prior year compensation and the other factors discussed below.

Name and Principal Position	Corporate Goal Weighting	Individual Goal Weighting	Brief Description of Material Individual Goals
Charles W. Shivery Chairman of the Board, President, and Chief Executive Officer of NU, Chairman of CL&P	60%	40%	Ensure the effective execution of NU s articulated 2010 operating and capital plans as approved. Special emphasis should be given to ensuring that operational leadership continues to transition to the appropriate level within the organization, through the use of well defined expectations and metrics. Implement NU s new safety initiatives and make measurable improvement in safety related results (20 percent of individual goals).
			Ensure the effective execution of NU s articulated strategic plan for 2010-2014. Continue to shape the implementation of energy policy in New England, consistent with NU s strategic plan to benefit its customers (20 percent of individual goals).
			Identify a strategic vision and the associated opportunities that are in addition to the current transmission-centric strategy and ensure the appropriate organizational structure, resources and culture to position NU for future success (20 percent of individual goals).
			Continue to embed sustainability into NU s operations and relationships with its key stakeholders. Achieve improvement in NU s reputation among its various stakeholders. (10 percent of individual goals).
			Implement cultural changes necessary for NU to succeed in an increasingly customer-centric environment. Continue to advance NU s succession planning and leadership development program to improve the depth and breadth of leadership talent. Lead through tone and actions NU s efforts to realize its vision to create an inclusive environment and a diverse workforce (10 percent of individual goals)

			Assist the Committee on Succession Planning and the Board of Trustees to ensure the smooth implementation of the succession planning process and to provide a seamless transition of leadership for NU and its stakeholders (20 percent of individual goals).
David R. McHale Executive Vice President and Chief Financial Officer	60%	40%	Successfully execute operating plans: support NU s strategy, 2010 operating plan, and competitive businesses, and improve effectiveness of shared services (40 percent of individual goals).
			Provide critical subject matter and execution expertise to advance NU s strategy while ensuring integrity of its financial position (20 percent of individual goals).
			Manage department budgets and expenditures; continue to execute internal customer focus strategy (15 percent of individual goals).
			Effectively communicate NU s strategy and financial position to stakeholders, with particular emphasis on investors, and throughout NU (15 percent of individual goals).
			Achieve organization development goals: continue to ensure the effective organizational design of the finance and shared services organizations; manage for an inclusive environment and diverse workforce (10 percent of individual goals).

Leon J. Olivier Executive Vice President and Chief Operating Officer of NU; Chief Executive Officer of CL&P	50%	50%	Advance NU s strategic objectives (40 percent of individual goals).
			Achieve NU s 2010 utility operating plans emphasizing execution, improvement, and Regulated company operational objectives (30 percent of individual goals).
			Work with NU s chief executive officer and members of NU s executive team to build stakeholder confidence (10 percent of individual goals).
			Achieve 2010 Customer Experience goals and objectives (10 percent of individual goals).
			Implement planned safety initiatives and make measureable improvements in overall safety results; continue to build and maintain a diverse and quality workforce (10 percent of individual goals).
Gregory B. Butler Senior Vice President and General Counsel	50%	50%	Manage NU s Legal Department to enable NU to achieve its strategic plan and 2010 operating and capital financing objectives; provide leadership with respect to uncollectibles expense and HWP Company site remediation (30 percent of individual goals).
			Develop Legislative, Regulatory, Legal, and Communications plans and provide expertise for NU s strategic initiatives and emerging opportunities (30 percent of individual goals).

			Achieve successful outcomes in federal and state energy regulatory legislative proceedings; contribute to positioning NU as a leading regional and national expert on energy issues (25 percent of individual goals).
			Provide quality internal customer support; execute talent management and development plans; manage budget (15 percent of individual goals).
James B. Robb Senior Vice President Enterprise Planning and Development of NUSCO	50%	50%	Develop comprehensive energy productivity and renewable generation strategies that align NU s objectives, shareholder aspirations, and customer needs; finalize key commitments established for the northern transmission opportunities (75 percent of individual goals).
			Continue to build NU s reputation for sustainability and build on its emerging reputation as a thought leader on energy issues; evolve NU s thinking regarding key policy issues in the energy sector, including policies around electric vehicles. (25 percent of individual goals).

2010 Results

The 2010 actual ANI was $400.6 million, which exceeded the maximum ANI amount. As a result, a portion of the total annual incentive payment to each NEO was attributable to achieving the corporate goal at 200 percent of target. In addition, the 2010 actual ANI exceeded the individual goal threshold. Accordingly, the balance of the annual incentive payment to each NEO was based on the extent to which each NEO achieved his individual goals.

Mr. Shivery s Annual Incentive Payment

The Compensation Committee and the Corporate Governance Committee assessed Mr. Shivery s performance on his individual goals described in the table above. The Committee determined that Mr. Shivery s execution of NU s long-term strategic plan as well as NU s 2010 operating and capital plans exceeded expectations. NU's financial performance improved over 2009 due in part to cost controls while at the same time, energy rates paid by NU's customers continued to trend downward. Additionally, NU invested approximately $1

billion in 2010 strengthening and expanding the energy infrastructure of Connecticut, Massachusetts and New Hampshire. This investment supports the provision of reliable energy service, as well as the region's economic development. While NU began the year with a number of operational and economic uncertainties, it achieved fair and reasonable outcomes in multiple-year electric distribution rate cases, reached key milestones for the Northern Pass transmission project, secured key approvals to advance the New England East-West Solutions projects for improved interstate reliability, and achieved significant improvements in safety and Customer Experience. Mr. Shivery continued to improve the depth and breadth of NU s leadership talent and to advance NU s succession planning programs. With Mr. Shivery s leadership, NU is well positioned for the future as it plans for the proposed merger with NSTAR.

Coupled with NU s overall corporate performance measured by ANI, the Compensation Committee members applied judgment to determine their recommendation for Mr. Shivery s annual incentive payment. Following a detailed review of these factors without Mr. Shivery present, the Board of Trustees awarded Mr. Shivery an annual incentive payment of $1,987,200 for 2010, consisting of $1,242,000 attributable to the achievement of 200 percent of the corporate goal and an additional $745,200 attributable to Mr. Shivery s performance of his individual goals. The Board of Trustees determined that this annual incentive payment was consistent with Mr. Shivery s above-expectations performance based on corporate, financial and individual criteria established for 2010. Mr. Shivery s annual incentive payment exceeds that of the other NEOs because of his significantly greater duties and responsibilities as NU s chief executive officer.

NEO Annual Incentive Payments

In addition to NU s corporate ANI goal described above, the Compensation Committee considered individual performance goals and other factors in determining the annual incentive payments for each of the other NEOs. These factors included the annual incentive payment recommendations made by Mr. Shivery with respect to each of the other NEOs and the scope of such NEO s responsibilities, performance, and impact on or contribution to NU s corporate success and growth. The annual incentives paid to each of the other NEOs as described below include the corporate ANI goal component for 2010.

Name and Principal Position	Annual Incentive Payment	2010 Accomplishments
Leon J. Olivier CEO of CL&P; Executive Vice President and Chief Operating Officer of NU	$601,494	The Compensation Committee determined that Mr. Olivier and his team effectively executed NU s operating plan within a challenging economy. Accomplishments included attainment of milestones related to Northern Pass transmission project, NEEWS, Yankee Gas pipeline expansion initiatives, customer service enhancements, and effective completion of the year s capital program.

David R. McHale Executive Vice President and Chief Financial Officer	$608,517	The Compensation Committee determined that Mr. McHale and his organization successfully issued debt on favorable terms, maintaining and enhancing liquidity through a period of continued economic contraction. Mr. McHale and his team also achieved higher than expected margins from NU s competitive businesses. Mr. McHale and his organization provided critical subject matter expertise and financial, analytical and risk management support for NU s major strategic initiatives, allowing it to successfully pursue new opportunities, including the Northern Pass transmission project and the proposed merger with NSTAR.
Gregory B. Butler Senior Vice President and General Counsel	$458,320	The Compensation Committee determined that Mr. Butler and his team contributed significantly to NU s operational and strategic accomplishments by achieving fair and reasonable outcomes in various federal and state regulatory proceedings and by providing extensive support for various strategic initiatives, including the Northern Pass transmission project and the proposed merger with NSTAR. His team continued to position NU as a leading regional and national expert on energy issues.
James B. Robb Senior Vice President Enterprise Planning and Development of NUSCO	$339,000	The Compensation Committee determined that Mr. Robb and his team were instrumental in finalizing and executing agreements on the Northern Pass transmission project. Mr. Robb and his team have continued to develop smart grid and electric vehicle strategies to better meet NU s customers needs and improve the efficiency of NU s operations.

LONG-TERM INCENTIVE PROGRAMS

General

Under NU s Long-Term Incentive Programs, the Compensation Committee of NU s Board of Trustees acting jointly with the Corporate Governance Committee of NU s Board of Trustees recommends to the NU Board of Trustees a long-term incentive target grant value for Mr. Shivery as a percentage of base salary on the date of grant. This recommendation is presented to the Board of Trustees for approval. The Compensation Committee also approves long-term incentive target grant values for each of the other NEOs as a percentage of base salary on the date of grant. For the 2010 2012 Long-Term Incentive Program, at target, each grant generally consisted of 25 percent RSUs and 75 percent performance units (one-half of which was performance cash and one-half of which were performance shares), subject to adjustment by the Compensation Committee (except the Compensation Committee acts jointly with the Corporate Governance Committee in recommending to the Board of Trustees adjustments to Mr. Shivery s targets), reflecting the Committee s desire to balance the roles of total shareholder return and NU s corporate financial performance in NU s compensation programs.

For the 2010 2012 program, the Compensation Committee acting jointly with the Corporate Governance Committee recommended to the Board of Trustees a long-term incentive compensation target for Mr. Shivery at 300 percent of base salary, which the Board approved. The Compensation Committee established long-term incentive compensation targets at 100 percent to 150 percent of base salary for the remaining NEOs.

Restricted Share Units (RSUs)

Each RSU granted under the long-term incentive program entitles the holder to receive one NU common share at the time of vesting. All RSUs granted in 2010 will vest in equal annual installments over three years. RSU holders are eligible to receive reinvested dividend units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU common shares. Reinvested dividend units are accounted for as additional RSUs that accrue and are distributed with the common shares issued upon vesting and distribution of the underlying RSUs. Common shares, including any additional common shares in respect of reinvested dividend units, are not issued for any RSUs that do not vest.

General

Annually, the Compensation Committee determines RSU grants for each officer participating in the long-term incentive program. Initially, the target RSU grants are equal to 25 percent of the long-term incentive compensation target for each officer. RSU grants are based on a percentage of base salary and measured in dollars. The percentage used for each officer is based on the officer s position in the company and ranges from 9 percent to 75 percent of salary. The Committee reserves the right to increase or decrease the RSU grant from target for each officer under special circumstances. The Compensation Committee acting jointly with the Corporate Governance Committee recommends to the Board of Trustees the final RSU grant for Mr. Shivery. Based on input from Mr. Shivery, the Compensation Committee determines the final RSU grants for each of the other officers, including the other NEOs.

All RSUs are granted on the date of the Committee meeting at which they are approved. RSU grants are subsequently converted from dollars into NU common share equivalents by dividing the value of each grant by the average closing price for NU common shares during the last ten trading days in January in the year of the grant.

RSU Grants under the 2010 2012 Program

Under the 2010 2012 program, the target RSU grant totaled approximately $2.4 million for all 31 officers participating in the long-term incentive program. The Committee did not adjust any officer s RSU grant from target for the 2010 2012 program. Accordingly, the final total RSU grant for officers, including Mr. Shivery, was unchanged from target. Dividing the final total RSU grant by $25.74, the average closing price for NU common shares during the last ten trading days in January 2010, resulted in an aggregate of 93,843 RSUs. The following RSU grants at 100 percent of target were approved, reflected in RSUs: Mr. Shivery: 30,157; Mr. McHale: 7,649; Mr. Olivier: 8,103; Mr. Butler: 5,929; and Mr. Robb: 3,885.

Performance Units

General

Performance units are a performance-based component of NU s long-term incentive program. A new three-year program commences every year. Performance unit grants are equal to 75 percent of total individual long-term incentive grants at target. The performance-based component of NU s long-term incentive programs has continued to evolve over the three prior years by shifting a portion of performance cash in earlier programs to performance shares in more recent programs to further strengthen the alignment of the performance elements with NU s shareholders.

Long-Term Incentive Program	**Percentage of Performance Cash**	**Percentage of Performance Shares**
2008 - 2010	100%	0%
2009 - 2011	67%	33%
2010 - 2012	50%	50%
2011 - 2013	0%	100%

The Committee approved the 2010 - 2012 program in early 2010. One-half of the performance unit grant in the 2010 - 2012 program consisted of a performance cash grant and the remaining one-half of each performance unit grant consisted of a performance share grant. Consequently, performance cash grants and performance share grants were each equal to 37.5 percent of the total individual long-term incentive grants at target. Under all of NU s long-term programs, both performance cash grants and performance share grants are measured in dollars. Performance share grants are subsequently converted from dollars into NU common share equivalents by dividing the value of each grant by the average closing price for NU common shares during the last ten trading days in January in the year of the grant. During the three-year performance program period, the dividends that would have been paid with respect to the performance shares to holders of performance share grants are accounted for as additional common shares that accrue and are distributed with the common shares, if any, at the end of the program.

Awards under a program are earned to the extent to which NU achieves goals in the four metrics described below during each year of the program, except as reduced in the discretion of the Compensation Committee. The Compensation Committee determines the actual awards, if any, only after the end of the final year in the respective program.

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Cumulative Adjusted Net Income, which is consolidated NU net income adjusted by the Compensation Committee to exclude the effects of certain nonrecurring income and expense items or events (which are defined as ANI under the annual incentive program) over the three years in a program. (20%)

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Average adjusted ROE, which is the average of the annual return on equity for NU for the three years in a program. The Committee adjusts average ROE on the same basis as cumulative adjusted net income. (20%)

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Average credit rating of NU (excluding the regulated companies), which is the time-weighted average daily credit rating by the rating agencies Standard & Poor s, Moody s, and Fitch. The metric is calculated by assigning numerical values, or "points," to credit ratings (A or A2: 5; A- or A3: 4; BBB+ or Baa1: 3; BBB or Baa2: 2; and BBB- or Baa3: 1) so that a large point value represents a high credit rating. In addition to average credit rating objectives, the ratings of NU by S&P and Moody s must remain above investment grade. (20%)

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Relative total shareholder return of NU as compared to the return of the utility companies listed in the performance peer group identified for each long term incentive program. (40%)

The selection of these four metrics reflects the Compensation Committee s belief that these areas are critical measurements of corporate success. Each metric was weighted equally in the 2009 - 2011 program. In the 2010 - 2012 program, the weighting of the total shareholder return metric was increased to 40 percent and the remaining three metrics were reduced to 20 percent each, to strengthen the alignment between executives and shareholders. The Committee measures performance against the cumulative adjusted net income, average adjusted ROE, and average credit rating, because these metrics are directly related to NU s multi-year business plan in effect at the beginning of the three-year program. The Committee also measures performance against relative total shareholder return to emphasize to the plan participants the importance of achieving total shareholder returns that are comparable to the returns for companies listed in the performance peer group. Before any amount is payable with respect to a metric, NU must achieve a minimum level of performance under that metric. If NU achieves the minimum level of performance for any goal, then the resulting payout will equal 50 percent of the target for that goal. If NU achieves the maximum level of performance for any goal, then the resulting payout will equal 150 percent of target for that goal. The Committee fixed the minimum opportunity at 50 percent of target and the maximum opportunity at 150 percent of target because the Committee believes this range is consistent with the ranges used by companies listed in the performance peer group.

Upon closing of the proposed merger with NSTAR, the extent of satisfaction of the performance goals applicable to Performance Units for performance periods not yet completed in the 2009 - 2011 program and the 2010 - 2012 program generally will be measured based on performance up to the closing of the merger and payment generally will be made on a pro-rata basis (based on the portion of the applicable performance period that had been completed upon closing of the merger) following the end of the original performance period conditioned upon continued employment through such date. Performance Units outstanding immediately before the closing of the merger that are attributable to the portion of the applicable performance periods extending beyond the closing of the merger will be forfeited. However, if an executive officer experiences a qualifying termination of employment (a termination of employment before age 65 without cause or by the executive officer for good reason) before completion of the original performance period, the awards will be vested at target performance levels and paid out without pro-ration upon such termination.

Subject to the closing of the merger, the Committee intends to grant to each executive officer whose awards are paid on a pro-rated basis as described in the preceding paragraph a make-whole award of RSUs with a value equal to the value of the executive officer s Performance Units outstanding at target immediately before the closing of the merger that are attributable to the portion of the applicable performance periods extending beyond the closing of the merger.

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Set forth below are descriptions of each of the three long-term performance programs that were in effect during 2010. The peer groups used by the Committee for performance comparisons under each program are listed in footnote 1 to the table that accompanies each description. The performance peer groups represent companies with investment profiles, including growth potential, business models and areas of focus substantially similar to NU s. The Committee compared NU s total shareholder return to the total shareholder returns of the companies in the performance peer group. Prior to the 2009 - 2011 program, the customized peer group had been larger than the performance peer groups because NU competes for talent with more companies than those with which it competes for investment. However, beginning with the 2009 - 2011 Long-Term Incentive Program, to simplify the peer group structure, the Committee evaluates the total shareholder return metric using the same customized group of peer utilities described above under "Market Analysis."

2008 - 2010 Performance Cash

The Compensation Committee approved the 2008 - 2010 performance cash grants in early 2008. Upon completion of NU s fiscal year ended 2010, the Committee determined that NU achieved goals under each of the four metrics during the three-year program and, accordingly, that awards under the program were payable at an overall level of 114 percent of target.

The 2008 2010 program included goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2008 2010 program, cumulative adjusted net income and average adjusted ROE excluded the positive and negative effects of the following nonrecurring income and expense items or events:

<u>**Excluded Categories**</u>		**Specific 2010 Adjustments ($ in millions)**
Changes to net income as the result of accounting or tax law changes	$	(5.1)
Delay in planned asset transactions	$	1.8
Incremental NSTAR merger costs	$	(9.4)
Net Adjustments:	$	

(12.7)

The table set forth below describes the goals under the 2008 2010 program and NU s actual results during that period:

Goal	2008 2010 Program Goals Minimum	Target	Maximum	Actual Results
	$	$	$	$
Cumulative Adjusted Net Income ($ in millions)	845.7	939.7	1,033.7	1,023.2
Average Adjusted ROE	8.6%	9.5%	10.5%	10.1%
Average Credit Rating Points	1.2	1.7	2.2	1.7
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th	53rd

(1)

Goals were evenly weighted in the 2008 -2010 program.

(2)

The performance peer group for the 2008 - 2010 program includes Northeast Utilities and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, Consolidated Edison, Inc., NiSource, Inc., NSTAR, NV Energy, Inc., Pepco Holdings, Inc., Pinnacle West Capital Corporation, SCANA Corporation, TECO Energy, Inc., Wisconsin Energy Corporation and Xcel Energy Inc.

Based on NU s financial performance during the three-year performance period, the total payout under the 2008 - 2010 Long-Term Incentive Program equaled 114 percent of target. As a result, the Committee approved the following performance cash awards: Mr. Shivery: $1,769,850; Mr. McHale: $427,500; Mr. Olivier: $381,188; Mr. Butler: $347,975; and Mr. Robb: $228,000. The payments were determined pursuant to formulas set forth in the 2008 - 2010 Long-Term Incentive Program and were not subject to the discretion of the Compensation Committee.

2009 2011 Performance Units

The Committee approved the 2009 2011 performance unit goals in early 2009. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the end of NU s 2011 fiscal year, which is the final year in the three-year program.

As described above, under the 2009 2011 program, two-thirds of each performance unit grant consists of a performance cash grant and the remaining one-third of each performance unit grant consists of a performance share grant. The 2009 2011 program also includes goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2009 2011 program, cumulative adjusted net income and average adjusted ROE exclude the positive and negative effects of the following nonrecurring income and expense items or events: accounting or tax law changes; unusual Internal Revenue Service or regulatory issues; unexpected changes in costs related to nuclear decommissioning; unexpected changes in costs related to environmental remediation of HWP Company; divestiture or discontinuance of a segment or component of NU s business; the acquisition of shares or assets of another entity comprising an additional segment or component of NU s business; and impairments on goodwill acquired before 2003 (more than six years prior to the beginning of this program cycle).

The table set forth below describes the goals under the 2009 2011 program:

Goal	2009 2011 Program Goals Minimum	Target	Maximum
	$	$	$
Cumulative Adjusted Net Income ($ in millions)	899.3	999.2	1,099.1
Average Adjusted ROE	8.4%	9.3%	10.1%
Average Credit Rating Points	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th

(1)

Goals were evenly weighted in the 2009 2011 program.

(2)

The performance peer group for the 2009 2011 program includes Northeast Utilities and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, Consolidated Edison, Inc., DTE Energy Company, Great Plains Energy Incorporated, Integrys Energy Group Inc., NiSource, Inc., NSTAR, NV Energy, Inc., OGE Energy Corp., Pepco Holdings, Inc., Pinnacle West Capital Corporation, Progress Energy Inc., SCANA Corporation, TECO Energy, Inc., Wisconsin Energy Corporation and Xcel Energy Inc.

2010 2012 Performance Units

The Committee approved the 2010 2012 performance unit goals in early 2010. No awards have been paid under this program, and the Committee will not determine whether any awards are payable until the end of NU s 2012 fiscal year, which is the final year in the three-year program.

As described above, under the 2010 2012 program, one-half of each performance unit grant consists of a performance cash grant and the remaining one-half of each performance unit grant consists of a performance share grant. The 2010 2012 program also includes goals in four metrics: cumulative adjusted net income, average adjusted ROE, average credit rating, and relative total shareholder return, as described below. For the 2010 2012 program, cumulative adjusted net income and average adjusted ROE exclude the positive and negative effects of the following nonrecurring income and expense items or events: accounting or tax law changes; unusual Internal Revenue Service or regulatory issues; unexpected changes in costs related to nuclear decommissioning; unexpected changes in costs related to environmental remediation of HWP Company; divestiture or discontinuance of a segment or component of NU s business; the acquisition of shares or assets of another entity comprising an additional segment or component of NU s business; and impairments on goodwill acquired before 2003 (more than seven years prior to the beginning of this program cycle).

The table set forth below describes the goals under the 2010 2012 program:

	2010 2012 Program Goals		
Goal	**Minimum**	**Target**	**Maximum**
	$	$	$
Cumulative Adjusted Net Income ($ in millions)	1,051.6	1,168.4	1,285.2
Average Adjusted ROE	9.0%	9.9%	10.7%
Average Credit Rating Points	1.2	1.7	2.2
Relative Total Shareholder Return (percentile) (1)	40th	60th	80th

(1)

Relative total shareholder return accounted for 40 percent of the performance units granted in the 2010 2012 program while the cumulative adjusted net income, average adjusted ROE, and average credit rating metrics each accounted for 20 percent of the performance units granted.

(2)

The performance peer group for the 2010 2012 program includes Northeast Utilities and the following companies: Allegheny Energy, Inc., Alliant Energy Corporation, Ameren Corporation, CenterPoint Energy, Inc., CMS Energy Corporation, Consolidated Edison, Inc., DTE Energy Company, Great Plains Energy Incorporated, Integrys Energy Group Inc., NiSource, Inc., NSTAR, NV Energy, Inc., OGE Energy Corp., Pepco Holdings, Inc., Pinnacle West Capital Corporation, Progress Energy Inc., SCANA Corporation, TECO Energy, Inc., Wisconsin Energy Corporation and Xcel Energy Inc.

2011 CHANGES

2011 2013 Long-Term Incentive Program

In late-2010, the Compensation Committee changed the performance component of the 2011 2013 Long-Term Incentive Program to 100 percent performance shares to further strengthen the alignment of the performance component with NU s shareholders. For the 2011 2013 program, the grant value at target will consist of 75 percent performance shares. RSUs will continue to constitute the remaining 25 percent of the grant value at target, unchanged from the 2010 2012 program. Upon the closing of the proposed merger with NSTAR, all outstanding 2011 2013 performance shares will be converted to RSUs assuming a target level of performance. These RSUs will vest according to the schedule that applies to the RSU component already granted as part of the 2011 2013 Long-Term Incentive Program.

NORTHEAST UTILITIES RETENTION PLAN

In light of the extraordinary nature of the proposed merger between NU and NSTAR, on November 16, 2010, the NU Board of Trustees established a retention pool in an aggregate amount of $10 million to be allocated to key employees, including some or all executive officers, to help ensure their continued dedication to NU both before and after completion of the merger. Awards to executive officers are established by the Committee, are in the form of restricted share units and generally vest subject to three years of continuous service following completion of the merger. Full payment will also be made if an eligible executive dies, becomes disabled, or is terminated without cause before the end of the retention period, in which case the retention payment will be reduced by the amount of any cash severance payable to the executive upon or during the year following termination. On November 16, 2010, the Committee granted retention awards to the following Named Executive Officers: Mr. Butler: 48,077 RSUs; Mr. McHale: 64,103 RSUs; Mr. Olivier: 48,077 RSUs; and Mr. Robb: 32,052 RSUs.

CLAWBACKS

If our earnings were to be restated as a result of noncompliance with accounting rules caused by fraud or misconduct, the Sarbanes-Oxley Act of 2002 would require our CEO and our Chief Financial Officer to reimburse NU for certain incentive compensation received by each of them. To the extent that reimbursement were not required under Sarbanes-Oxley, NU s Incentive Plan would require any employee whose misconduct or fraud caused such restatement, as determined by the Board of Trustees, to reimburse NU for any incentive compensation received by him or her. To date, there have been no restatements to which either the Sarbanes-Oxley clawback provisions or the Incentive Plan clawback provisions would apply.

SHARE OWNERSHIP GUIDELINES

Effective in 2006, the Compensation Committee approved share ownership guidelines to emphasize the importance of share ownership by certain of NU s executive officers. The Committee most recently reviewed the guidelines for these executive officers in 2010 and determined that they remain reasonable and require no modification. The guidelines call for Mr. Shivery to own 200,000 NU common shares, which is currently valued at approximately five- to six-times base salary, and the other executive officers to own a minimum number of common shares valued at approximately two- to three-times base salary.

Executive Officer	Ownership Guidelines (Number of Shares)	Approximate Salary Multiple
Mr. Shivery	200,000	5-6
EVPs/SVPs	30,000 45,000	2-3
VPs	3,000 17,500	1.2

At the time the share ownership guidelines were implemented, the Committee required NU s executive officers to attain these ownership levels within five years. The Committee requires all newly-elected executive officers to attain the ownership levels within five to seven years. All of our executive officers, including our NEOs, have satisfied, or are expected to satisfy, the share ownership guidelines within the applicable time frame. Common shares, whether held of record, in street name, or in individual 401(k) accounts, and RSUs satisfy the guidelines. Unexercised stock options and unvested performance shares do not count toward the ownership guidelines.

SUPPLEMENTAL BENEFITS

NU provides a variety of basic and supplemental benefits designed to assist it in attracting and retaining executive officers critical to NU s success by reflecting competitive practices. The Compensation Committee endeavors to adhere to a high level of propriety in managing executive benefits and perquisites. NU does not provide permanent lodging or personal entertainment for any executive officer or employee, and our executive officers are eligible to participate in substantially the same health care and benefit programs available to NU employees.

RETIREMENT BENEFITS

NU provides retirement income benefits for employees, including executive officers, who commenced employment before 2006 under the Northeast Utilities Service Company Retirement Plan (Retirement Plan) and, for officers, under the Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies (Supplemental

Plan). Each plan is a defined benefit pension

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plan, which determines retirement benefits based on years of service, age at retirement, and "plan compensation." Plan compensation for the Retirement Plan, which is a qualified plan under the Internal Revenue Code, includes primarily base pay and nonofficer annual incentives up to the Internal Revenue Code limits for qualified plans. Beginning in 2006, newly-hired nonunion employees, including Mr. Robb and other executive officers, participate in an enhanced defined contribution retirement program in the Northeast Utilities Service Company 401k Plan (401k Plan), called the K-Vantage benefit, instead of participating in the Retirement Plan.

For NEOs who participate in the Retirement Plan, the Supplemental Plan adds to plan compensation: base pay over the Internal Revenue Code limits; deferred base salary; annual executive incentive program awards; and, for certain participants, long-term incentive program awards, as explained in the narrative accompanying the Pension Benefits Table.

The Supplemental Plan consists of two parts. The first part, called the make-whole benefit, compensates for benefits lost due to Internal Revenue Code limitations on benefits provided under the Retirement Plan. The second part, called the target benefit, is available to all NEOs except Mr. Olivier and Mr. Robb. The target benefit supplements the Retirement Plan and make-whole benefit under the Supplemental Plan so that, upon attaining at least 25 years of service, total retirement benefits from these plans will equal a target percentage of the final average compensation. To receive the target benefit, a participant must remain employed by NU or its subsidiaries at least for five years and until age 60, unless the Board of Trustees establishes a lower age.

The value of the target benefit was reduced in 2005 to reflect changes in competitive practices, which indicated general reductions in the prevalence of defined benefit plans and the value of special retirement benefits to senior executives. Individuals who began serving as officers before February 2005 are eligible to receive a target benefit with the target percentage fixed at 60 percent. Individuals who began serving as officers from and after February 2005 are eligible to receive a target benefit with the target percentage fixed at 50 percent. As a result, Messrs. Shivery and Butler have target benefits at 60 percent while Mr. McHale has a target benefit at 50 percent.

Mr. Shivery s employment agreement provides for a special total retirement benefit determined using the Supplemental Plan target benefit formula plus three additional years of company service. This benefit will be reduced by two percent per year for each year Mr. Shivery retires before age 65. Upon retirement, Mr. Shivery will be eligible to receive retirement health benefits. In addition, the Named Executive Officers are eligible to receive certain health and welfare benefits upon termination of employment following a change of control or, for Messrs. Shivery, Olivier, McHale and Butler, an involuntary termination of employment. To the extent such benefits may not be provided through NU s tax qualified plans, the executive is entitled to participate in a non-qualified health plan that will be treated as taxable compensation to the executive officer to the extent of company contributions and will be provided with a tax gross-up so that the value to the executive is equivalent to a tax qualified plan benefit. See the Pension Benefits Table and the accompanying narrative for more details of these arrangements.

NU entered into an employment agreement with Mr. Olivier that includes retirement benefits similar to the benefits provided by his previous employer. Accordingly, Mr. Olivier is entitled to receive separate retirement benefits in lieu of the Supplemental Plan benefits described above. Pursuant to his agreement, Mr. Olivier will receive a targeted pension value if he meets certain eligibility requirements. See the Pension Benefits Table and the accompanying narrative for more details of this arrangement.

401K PLAN

NU provides an opportunity for employees to save money for retirement on a tax-favored basis through the 401k Plan. The 401k Plan is a defined contribution qualified plan under the Internal Revenue Code and contains a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code. Participants with at least six months of service receive employer matching contributions, not to exceed 3 percent of base compensation, one-third of which are in cash available for investment in various mutual fund alternatives and two-thirds of which are in the form of NU common shares (ESOP shares).

The K-Vantage benefit provides for employer contributions to the 401k Plan in amounts between 2.5 percent and 6.5 percent of plan compensation based on an eligible employee s age and years of service. These contributions are in addition to employer matching contributions. Mr. Robb and other executive officers hired beginning in 2006 also participate in a companion nonqualified K-Vantage benefit in the Nonqualified Deferred Compensation Plan (Deferral Plan) that provides defined contribution benefits above Internal Revenue Code limits on qualified plans.

MED-VANTAGE PLAN

NU automatically enrolls K-Vantage employees who have attained at least age 40 in the Med-Vantage Plan to help pay for medical expenses, including healthcare premiums on a tax-favored basis upon the employee's termination of employment. Eligible full-time employees receive employer contributions of $1,000 per year**.**

NONQUALIFIED DEFERRED COMPENSATION PLAN

Our executive officers participate in the Deferral Plan to provide additional retirement benefits not available in NU s 401k Plan because of Internal Revenue Code limits on qualified plans. Under the Deferral Plan, executive officers are entitled to defer up to 100 percent of base salary and annual incentive awards. NU matches officer deferrals in an amount equal to 3 percent of the amount of base salary above Internal Revenue Code limits on qualified plans. The matching contribution is deemed to be invested in NU common shares and vests at the end of the third year after the calendar year in which the matching contribution was earned, or at retirement, whichever occurs first. Participants are entitled to select deemed investments for all deferred amounts from the same investments available in the 401k Plan, except for investments in NU s common shares. NU also credits the Deferral Plan in amounts equal to the K-Vantage

benefit that would have been provided under the 401k Plan but for Internal Revenue Code limits on qualified plans. This nonqualified plan is unfunded. Please see the Nonqualified Deferred Compensation Table and the accompanying notes for additional plan details.

PERQUISITES

It is NU s philosophy that perquisites should be provided to executive officers only as needed for business reasons, and not simply in reaction to prevalent market practices.

Senior executive officers, including the NEOs, are eligible to receive reimbursement for financial planning and tax preparation services. This benefit is intended to help ensure that executive officers seek competent tax advice, properly prepare complex tax returns, and leverage the value of NU s compensation programs. Reimbursement is limited to $4,000 every two years for financial planning services and $1,500 per year for tax preparation services.

All executive officers receive a special annual physical examination benefit to help ensure serious health issues are detected early. The benefit is limited to the reimbursement of up to $800 for fees incurred beyond those covered by NU s medical plan.

When hiring a new executive officer or transferring an executive officer to a new location, NU sometimes reimburses executive officers for reasonable temporary living and relocation expenses, or provides a lump sum payment in lieu of specific reimbursement. These expenses are grossed-up for income taxes attributable to such reimbursements so that relocation or transfer is cost neutral to the executive officer.

When required for a valid business purpose, an executive officer may be accompanied by his or her spouse, in which case NU will reimburse the executive officer for all spousal travel expenses.

Effective beginning in 2009, NU no longer pays gross-ups for taxes on any perquisites other than for taxes on reimbursement of relocation expenses for newly-hired or transferred executives.

CONTRACTUAL AGREEMENTS

NU has entered into employment and other agreements with certain executive officers, including the NEOs. The agreements specify all or part of the following: compensation and benefits during the employment term, benefits payable upon involuntary termination of employment, and benefits payable upon termination of employment following a change of control. These termination and change of control benefits were customary at the time the agreements were signed and were necessary to attract and retain competent and capable executive talent. NU continues to believe that these benefits help to ensure the executive officers dedication and objectivity at a time when they might otherwise be concerned about their future employment.

The agreements with Messrs. McHale, Butler and Robb provide for enhanced cash severance benefits in the event of a change of control and subsequent termination of employment without cause (as defined in the employment agreement, generally involving a felony conviction; acts of fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to NU property; gross misconduct or gross negligence in the course of employment; or a material breach of obligations under the agreement) or upon termination of employment by the executive for "good reason" (as defined in the employment agreement, generally meaning an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control). The Compensation Committee believes that termination for good reason is conceptually the same as termination "without cause" and, in the absence of this provision, potential acquirers would have an incentive to constructively terminate executives to avoid paying severance. The change of control provisions in Mr. Shivery s employment agreement expired when Mr. Shivery reached age 65. Mr. Olivier s employment agreement does not provide for severance payments in the event that his employment terminates following a change of control. Mr. Olivier participates instead in the Special Severance Program.

For Messrs. McHale and Butler, a "change of control" is defined in their employment agreements as a change in ownership or control effected through (i) the acquisition of 20 percent or more of the combined voting power of NU s common shares or other voting securities, (ii) a change in the majority of NU s Board of Trustees over a 24-month period, unless approved by a majority of the incumbent Trustees, (iii) certain reorganizations, mergers or consolidations where substantially all of the persons who were the beneficial owners of the outstanding common shares immediately prior to such business combination do not beneficially own more than 50 percent of the voting power of the resulting business entity, and (iv) complete liquidation or dissolution of NU, or a sale or disposition of all or substantially all of NU s assets other than to an entity with respect to which following completion of the transaction more than 50 percent of common shares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction. For Mr. Robb, a "change of control" is as defined in the shareholder-approved Northeast Utilities Incentive Plan.

Pursuant to the change of control provisions in the employment agreements, each NEO except for Mr. Olivier and Mr. Robb would be reimbursed for the full amount of any excise taxes imposed on severance payments and any other payments under Section 4999 of the Internal Revenue Code. This "gross-up" is intended to preserve the aggregate amount of the severance payments by compensating the executive officers for any adverse tax consequences to which they may become subject under the Internal Revenue Code. NU has not included gross-up provisions in any employment arrangements entered into with executive officers hired after Mr. Robb. Mr. Olivier s and Mr. Robb s severance payments may be reduced to avoid excise taxes.

We describe and explain how the appropriate payment and benefit levels are determined under the various circumstances that trigger payments or provision of benefits in the tables and accompanying footnotes appearing in the section captioned "Potential Payments Upon Termination or Change of Control," below.

To help protect NU after the termination of an executive officer s employment, the employment agreements include non-competition and non-solicitation covenants pursuant to which the executive officers have agreed not to compete with NU system companies or solicit NU companies employees for a period of two years (one year for Mr. Olivier pursuant to the Special Severance Program and one year for Mr. Robb pursuant to his agreement) after termination of employment.

In the event of termination of employment without "cause" or upon termination of employment by an NEO for good reason, in each case following a change of control, the expiration date of all vested unexercised stock options held by our NEOs would be extended automatically for up to an additional 36 months, but not beyond the original expiration date, to provide these holders with an opportunity to benefit from increased shareholder value created by the change of control. Also, in the event of a change of control, the long-term incentive programs provide for the vesting, pro rata based on the number of days of employment during the performance period, and payment at target of performance cash, whether or not the executive s employment terminates, unless the Committee determines otherwise.

Finally, in the event of a change of control, the Deferral Plan provides for the immediate vesting of any employer matches, although these matches would be paid according to the schedule defined by the executive s original election.

As discussed under the caption entitled "Supplemental Benefits," above, the employment agreements with Messrs. Shivery and Olivier also include additional retirement benefits payable upon voluntary termination of employment.

With respect to NU s proposed merger with NSTAR, Mr. Shivery is not entitled to severance benefits because he ceased being entitled to such benefits upon attaining age 65. Messrs. McHale and Butler are entitled to severance benefits upon a qualifying termination of employment without regard to whether the merger is completed because the merger does not constitute a change in control within the meaning of their employment agreements. Mr. Olivier will be entitled to benefits under the Special Severance Program in the event of a qualifying termination of employment within two years following the approval by NU s shareholders of the proposed merger. Pursuant to a supplemental agreement between NU and Mr. Olivier, Mr. Olivier is also entitled to a special retirement payment upon a qualifying termination of employment within two years following the approval by NU s shareholders of the merger. Mr. Robb will be entitled to benefits under his employment agreement in the event of a qualifying termination of employment within two years following the approval by NU s shareholders of the merger.

TAX AND ACCOUNTING CONSIDERATIONS

Tax Considerations. All executive compensation for 2010 was fully deductible by NU for federal income tax purposes, except for: (i) approximately $67,000 paid to Mr. Shivery, consisting primarily of RSU distributions.

Section 162(m) of the Internal Revenue Code limits the tax deduction for compensation paid to a company s CEO and certain other executives. NU is entitled to deduct compensation payments above $1 million as compensation expense only to the extent that these payments are "performance based" in accordance with Section 162(m) of the Internal Revenue Code. NU s annual incentive program and performance unit grants qualify as performance-based compensation under the Internal Revenue Code. As required by Section 162(m), the Compensation Committee reports to the Board of Trustees annually the extent to which various performance goals have been achieved. RSUs do not qualify as performance-based compensation.

Currently, Messrs. Shivery and Olivier are the only NEOs to exceed the Section 162(m) limit. To preserve an employee compensation tax deduction, Mr. Shivery agreed, for as long as it is beneficial to NU, to defer the distribution to him of NU common shares in respect of all vested RSUs until the calendar year after he leaves NU s employment, at which time Section 162(m) will no longer apply to him. The non-deductible RSU distributions for Mr. Shivery in 2010 described above relate to RSUs granted before Mr. Shivery was elected as NU s CEO.

Section 409A of the Internal Revenue Code provides that amounts deferred under nonqualified deferred compensation plans are includable in an employee s income when vested unless certain requirements are met. If these requirements are not met, employees are also subject to additional income tax and interest penalties. All of NU s supplemental retirement plans, executive employment agreements, severance arrangements, and other nonqualified deferred compensation plans were amended in 2008 to satisfy the requirements of Section 409A.

Section 280G of the Internal Revenue Code disallows a tax deduction for "excess parachute payments" in connection with the termination of employment related to a change of control (as defined in the Internal Revenue Code), and Section 4999 of the Internal Revenue Code imposes a 20 percent excise tax on any person who receives excess parachute payments. As discussed above, our NEOs are entitled to receive certain payments upon termination of their employment, including termination following a change of control. Under the terms of the agreements, all NEOs except Mr. Olivier and Mr. Robb are entitled to receive tax gross-ups for any payments that constitute an excess parachute payment. Accordingly, a tax deduction would be disallowed under Section 280G for all excess parachute payments as well as tax gross-ups. Not all of the payments to which NEOs are entitled are excess parachute payments. The amounts of the payments that constitute excess parachute payments are set forth in the tables found under the caption entitled "Potential Payments at Termination or Change of Control," below.

In the event of a change of control in which NU is not the surviving entity, RSUs granted to executive officers provide that the acquirer will assume or replace the grants, even if the executive remains employed after the change of control.

Accounting Considerations. RSUs and performance shares disclosed in the Grants of Plan-Based Awards Table are accounted for based on their grant date fair value, as determined under FASB ASC Topic 718, which is recognized over the service period, or the three-year vesting period applicable to the grant. Assumptions used in the calculation of this amount appear under the caption entitled *Management s Discussion and Analysis and Results of Operations* in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Forfeitures are estimated, and the compensation cost of the grants will be reversed if the employee does not remain employed by NU throughout the three-year vesting period. Performance unit grants are accounted for on a variable basis based on the most likely payment outcome.

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by CL&P s NEOs. As explained in the footnotes below, the amounts reflect the economic benefit to each Named Executive Officer of the compensation item paid or accrued on his behalf for the fiscal year ended December 31, 2010. All salaries, annual incentive amounts and long-term incentive amounts shown for each Named Executive Officer were paid for all services rendered to NU and its subsidiaries, including CL&P, in all capacities.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Stock Awards ($) (3)	Option Awards ($) (4)	Non-Equity Incentive Plan Compensation ($) (5)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($) (6)	All Other Compen-sation ($) (7)	Total ($)
Charles W. Shivery	2010	1,035,000		1,905,964		3,757,050	1,525,310	31,050	8,254,374
Chairman of the	2009	1,035,000		1,574,915		3,280,650	1,812,023	31,050	7,773,638
Board,	2008	1,067,404		1,891,430		3,257,929	1,627,493	35,397	7,879,653
President and CEO of NU;									
Chairman of CL&P									
David R. McHale	2010	525,000		2,484,707		1,036,017	934,059	15,750	4,995,533
Executive Vice	2009	524,520		399,436		923,603	1,038,268	7,350	2,893,177
President and	2008	508,654		456,858		750,214	514,753	9,907	2,240,386

Chief Financial Officer (8)							
Leon J. Olivier	2010	550,000	2,007,381	982,682	699,343	16,500	4,255,906
Executive Vice	2009	550,000	418,459	882,009	219,565	16,500	2,086,533
President and Chief Operating Officer of NU; CEO of CL&P	2008	550,962	407,367	839,571	324,854	18,997	2,141,751
Gregory B. Butler	2010	406,988	1,875,695	806,295	472,066	7,350	3,568,394
Senior Vice President and	2009	406,988	309,666	730,878	503,614	7,350	1,958,496
General Counsel	2008	418,542	327,261	723,674	206,850	8,207	1,684,534
James B. Robb	2010	400,000	1,246,211	567,000		45,243	2,258,454
Senior Vice President Enterprise Planning & Development of NUSCO	2009	400,000	202,896	316,500		44,237	963,634

(1)

Includes amounts deferred in 2010 by the Named Executive Officers under the Deferral Plan, as follows: Mr. Shivery: $31,050; Mr. McHale: $8,400; Mr. Olivier: $110,000; and Mr. Robb: $8,000. For more information, see the Executive Contributions in the Last Fiscal Year column of the Non-Qualified Deferred Compensation Plans Table.

NU pays each of its salaried employees, including each of the Named Executive Officers, 1/26th of their annual base salary every two weeks. This bi-weekly pay schedule typically results in one extra pay date per year approximately once every twelve years. One additional pay date occurred in 2008. Accordingly, the amounts reported for Salary for each Named Executive Officer in 2008 reflect 27 pay dates, as compared to 26 pay dates in each of 2009 and 2010.

(2)

No discretionary bonus awards were made to any of the Named Executive Officers in the fiscal years ended 2008, 2009 and 2010.

(3)

Reflects the aggregate grant date fair value of restricted share units (RSUs) and performance shares granted in each fiscal year, calculated in accordance with FASB ASC Topic 718.

In 2008, 2009 and 2010, certain Named Executive Officers were granted RSUs that vest in equal annual installments over three years as long-term incentive compensation. NU deferred the distribution of common shares upon vesting of RSUs granted to Mr. Shivery until the calendar year after he leaves employment. RSU holders are eligible to receive dividend equivalent units on outstanding RSUs held by them to the same extent that dividends are declared and paid on NU s common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares issued upon vesting of the underlying RSUs.

In 2010, certain Named Executive Officers were granted performance shares as long-term compensation. These performance shares will vest on December 31, 2012, based on the extent to which four performance conditions are achieved. The grant date values for the performance shares, assuming achievement of the highest level of all four performance conditions, are as follows: Mr. Shivery: $1,726,250; Mr. McHale: $437,820; Mr. Olivier: $458,657; Mr. Butler: $339,404; and Mr. Robb: $222,402.

In 2010, NU established a retention pool in an aggregate amount of $10 million to be allocated to key employees, including some or all of the executive officers, to help ensure their continued dedication to NU both before and after completion of the proposed merger with NSTAR. Awards to executive officers are determined by the Committee, are in the form of RSUs and generally vest subject to three years of continuous service following completion of the merger. Full payment will also be made if an eligible executive dies, becomes disabled, or his or her employment is terminated by NU without cause before the end of the retention period, in which case the retention payment will be reduced by the amount of any cash severance payable to the executive upon or during the year following termination. On November 16, 2010, the Committee granted retention awards to the following executive officers: Mr. McHale: 64,103 RSUs; Mr. Olivier: 48,077 RSUs; Mr. Butler: 48,077 RSUs; and Mr. Robb: 32,052 RSUs.

(4)

NU did not grant stock options to any of the Named Executive Officers in 2010. NU has not granted any stock options since 2002.

(5)

Includes payments to the Named Executive Officers under the 2010 Annual Incentive Program (Mr. Shivery: $1,987,200; Mr. McHale: $608,517; Mr. Olivier: $601,494; Mr. Butler: $458,320; and Mr. Robb: $339,000). Also includes performance cash payments under the 2008 2010 Long-Term Incentive Program (Mr. Shivery: $1,769,850; Mr. McHale: $427,500; Mr. Olivier: $381,188; Mr. Butler: $347,975; and Mr. Robb: $228,000). Performance goals under the 2010 Annual Incentive Program were communicated to each officer by Mr. Shivery or, in the case of Mr. Shivery, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2010. The Compensation Committee acting jointly with the Corporate Governance Committee determined the extent to which these goals were satisfied (based on input from Mr. Shivery, in the case of the other Named Executive Officers) in February 2011. Performance goals under the 2008 2010 Long-Term Incentive Program were communicated to each officer by Mr. Shivery or, in the case of Mr. Shivery, jointly by the Compensation Committee and Corporate Governance Committee, during the first 90 days of 2008. The Compensation Committee determined the extent to which the long-term goals were satisfied in February 2011.

(6)

Includes the actuarial increase in the present value from December 31, 2009 to December 31, 2010 of the Named Executive Officer s accumulated benefits under all of NU s defined benefit pension plans determined using interest rate and mortality rate assumptions consistent with those appearing under the caption entitled Management s Discussion and Analysis and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. The Named Executive Officer may not be fully vested in such amounts. More information on this topic is set forth in the notes to the Pension Benefits table, appearing further below. Mr. Robb does not participate in NU s defined benefit pension plan. There were no above-market earnings on deferrals in 2010.

(7)

Includes matching contributions of $7,350 allocated by NU to the account of each of the Named Executive Officers under the 401k Plan; plus Med-Vantage employer contributions (Mr. Robb: $1,000); plus qualified K-Vantage employer contributions under the 401k Plan (Mr. Robb: $11,025); plus nonqualified K-Vantage employer contributions under the Deferral Plan (Mr. Robb: $21,218); and employer matching contributions under the Deferral Plan for the Named Executive Officers who deferred part of their salary in the fiscal year ended December 31, 2010 (Mr. Shivery: $23,700; Mr. McHale: $8,400; Mr. Olivier: $9,150; and Mr. Robb: $4,650). Mr. Butler did not participate in the Deferral Plan in 2010.

(8)

Mr. McHale was elected Executive Vice President and Chief Financial Officer of CL&P effective January 1, 2009. He served as Senior Vice President and Chief Financial Officer of CL&P from January 1, 2005 until January 1, 2009.

(9)

Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU on May 13, 2008. He served as Executive Vice President Operations of NU from February 13, 2007 until May 13, 2008.

(10)

Mr. Robb did not meet the requirements for inclusion in the Summary Compensation Table and was not a Named Executive Officer for 2008. Mr. Robb became a Named Executive Officer in 2009.

GRANTS OF PLAN-BASED AWARDS DURING 2010

The Grants of Plan-Based Awards Table provides information on the range of potential payouts under all incentive plan awards during the fiscal year ended December 31, 2010. The table also discloses the underlying stock awards and the grant date for equity-based awards. NU has not granted any stock options since 2002. Accordingly, NU did not grant stock options to any of the Named Executive Officers in 2010.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**(#) (1)**	**($) (2)**
Charles W. Shivery						
Annual Incentive (3)	2/9/2010	517,500	1,035,000	2,070,000		
Long-Term Incentive (4)	2/9/2010	582,192	1,164,384	1,746,576	75,393	1,905,964
David R. McHale						
Annual Incentive (3)	2/9/2010	170,625	341,250	682,500		
Long-Term Incentive (4)	2/9/2010	147,650	295,300	442,950	19,122	483,411
Retention Award (5)	11/16/2010				64,103	2,000,014
Leon J. Olivier						
Annual Incentive (3)	2/9/2010	178,750	357,500	715,000		
Long-Term Incentive (4)	2/9/2010	154,688	309,376	464,064	20,032	506,417
Retention Award (5)	11/16/2010				48,077	1,500,002
Gregory B. Butler						
Annual Incentive (3)	2/9/2010	132,271	264,542	529,085		
Long-Term Incentive (4)	2/9/2010	114,469	228,938	343,407	14,823	374,731
Retention Award (5)	11/16/2010				48,077	1,500,002
James B. Robb						
Annual Incentive (3)	2/9/2010	100,000	200,000	400,000		
Long-Term Incentive (4)	2/9/2010	74,994	149,987	224,981	9,713	245,548
Retention Award (5)	11/16/2010				32,052	1,000,022

(1)

Includes the number of RSUs and performance shares granted to each of the Named Executive Officers on February 9, 2010 under the 2010 2012 Long-Term Incentive Program. Performance shares were granted with a three-year Performance Period that ends on December 31, 2012. At the end of the Performance Period, common shares will be awarded based on performance compared to goals, subject to reduction for applicable withholding taxes. RSUs vest in equal installments on February 25, 2011, 2012 and 2013. Except for Messrs. Shivery and Robb, NU will distribute common shares in respect to vested RSUs on a one-for-one basis immediately upon vesting, after reduction for applicable withholding taxes. For Mr. Shivery, NU will distribute common shares, after reduction for applicable withholding taxes, in respect of vested RSUs in three approximately equal annual installments beginning the later of (i) six months after he leaves the Company and (ii) January of the calendar year after he leaves the Company. For Mr. Robb, NU will distribute common shares after reduction for applicable withholding taxes, in respect of vested RSUs beginning the earlier of (i) fifteen years beyond the vesting date or (ii) six months after he leaves the Company. Holders of RSUs and performance shares are eligible to receive dividend equivalent units on outstanding RSUs and performance shares held by them to the same extent that dividends are declared and paid on NU s common shares. Dividend equivalent units are accounted for as additional common shares that accrue and are distributed simultaneously with the common shares distributed in respect of the underlying RSUs or performance shares. The Annual Incentive Program does not include an equity component.

Also includes the number of RSUs granted to certain Named Executive Officers on November 16, 2010 pursuant to the retention pool established in connection with the proposed merger with NSTAR. See note 3 to the Summary Compensation Table.

(2)

Reflects the grant-date fair value of RSUs and performance shares granted to the Named Executive Officers on February 9, 2010, under the 2010 2012 Long-Term Incentive Program determined pursuant to generally accepted accounting principles. The Annual Incentive Program does not include an equity component.

(3)

Amounts reflect the range of potential payouts, if any, under the 2010 Annual Incentive Program for each Named Executive Officer, as described in the Compensation Discussion and Analysis. The payment in 2011 for performance in 2010 is set forth in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. The threshold payment under the Annual Incentive Program is 50 percent of target. However, based on Adjusted Net Income and individual performance, the actual payment under the Annual Incentive Program could be zero.

(4)

Reflects the range of potential payouts, if any, pursuant to performance cash awards under the 2010 2012 Long-Term Incentive Program, as described in the Compensation Discussion and Analysis. Grants of three-year performance cash awards were made in 2010 under the 2010 2012 Long-Term Incentive Program. Performance cash will be fully vested at the

end of the performance period and paid to the officers in cash during the first fiscal quarter after the end of the performance period.

(5)

Reflects the number of RSUs granted to certain Named Executive Officers on November 16, 2010 pursuant to the retention pool established in connection with the proposed merger with NSTAR. See note 3 to the Summary Compensation Table.

EQUITY GRANTS OUTSTANDING AT DECEMBER 31, 2010

The following table sets forth option, RSU and performance share grants outstanding at the end of NU s fiscal year ended December 31, 2010 for each of the Named Executive Officers. All outstanding options were fully vested as of December 31, 2010.

	Option Awards (1)			Stock Awards (2)			
Name	**Number of Securities Underlying Unexercised Options Exercisable (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock that have not Vested (#) (3)**	**Market Value of Shares or Units of Stock that have not Vested ($)(4)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(5)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(6)**
Charles W. Shivery	29,024	$18.90	06/11/2012	80,206	2,556,972	82,191	2,620,249
David R. McHale				84,654	2,698,765	20,846	664,570
Leon J. Olivier				68,496	2,183,642	21,838	696,195
Gregory B. Butler				63,634	2,028,636	16,160	515,181
James B. Robb				42,381	1,351,092	10,589	337,577

(1)

NU has not granted stock options since 2002.

(2)

Awards and market values of awards appearing in the table and the accompanying notes have been rounded to whole units.

(3)

A total of 2,230 unvested RSUs held by Mr. Robb vested on September 4, 2010 plus 19 associated dividend equivalent units vested on September 30, 2010. An additional 87,294 unvested RSUs will vest on February 25, 2011 (Mr. Shivery: 49,531; Mr. McHale: 11,766; Mr. Olivier: 11,368; Mr. Butler: 8,759 and Mr. Robb: 5,870). An additional 40,929 unvested RSUs will vest on February 25, 2012 (Mr. Shivery: 22,187; Mr. McHale: 5,627; Mr. Olivier: 5,895; Mr. Butler: 4,362; and Mr. Robb: 2,858). An additional 19,222 unvested RSUs will vest on February 25, 2013 (Mr. Shivery: 10,419; Mr. McHale: 2,643; Mr. Olivier: 2,769; Mr. Butler: 2,049; and Mr. Robb: 1,342).

An additional 193,854 unvested RSUs granted pursuant to the retention pool will vest subject to three years of continuous service following completion of the merger with NSTAR (Mr. McHale: 64,618; Mr. Olivier: 48,463; Mr. Butler: 48,463; and Mr. Robb: 32,310). See note 3 to the Summary Compensation Table regarding retention pool grants.

(4)

The market value of RSUs is determined by multiplying the number of RSUs by $31.88, the closing price per share of common shares on December 31, 2010, the last trading day of the fiscal year.

(5)

Reflects the target payout level for 2010 and 2009 performance shares. Payouts for 2010 and 2009 performance shares will be based on actual performance. Performance shares are described in the CD&A and footnote (1) to the Grants of Plan-Based Awards table. Performance shares vest following a three-year performance period to the extent targets are achieved. Performance shares are also discussed in the CD&A under "Performance Units" above. A total of 65,126 unearned performance shares will vest on December 31, 2012 (Mr. Shivery: 35,303; Mr. McHale: 8,954; Mr. Olivier: 9,380; Mr. Butler: 6,941 and Mr. Robb: 4,548). An additional 86,498 unearned performance shares will vest on December 31, 2013 (Mr. Shivery: 46,888; Mr. McHale: 11,892; Mr. Olivier: 12,458; Mr. Butler: 9,219; and Mr. Robb: 6,041).

(6)

The market value is determined by multiplying the number of performance shares in the adjacent column by $31.88, the closing price per share of common shares on December 31, 2010, the last trading day of the fiscal year.

OPTIONS EXERCISED AND STOCK VESTED IN 2010

The following table reports amounts realized on equity compensation during the fiscal year ended December 31, 2010. None of the Named Executive Officers exercised options in 2010. The Stock Awards columns report the vesting of RSU grants to the Named Executive Officers in 2010.

	Option Awards		Stock Awards	
Name	**Number of Shares Acquired on Exercise (#)**	**Value Realized On Exercise ($) (1)**	**Number of Shares Acquired on Vesting (#) (2)**	**Value Realized on Vesting ($) (3)**
Charles W. Shivery			70,957	1,863,346
David R. McHale			15,568	408,816
Leon J. Olivier			14,248	374,188
Gregory J. Butler			11,526	302,672
James J. Robb			6,618	181,049

(1)

Represents the amounts realized upon option exercises, which is the difference between the option exercise price and the market price at the time of exercise.

(2)

Includes RSUs granted to our Named Executive Officers under NU s long-term incentive programs, including dividend reinvestments, as follows:

Name	**2007 Program**	**2008 Program**	**2009 Program**
Charles W. Shivery	35,087	24,517	11,353
David R. McHale	6,767	5,922	2,879
Leon J. Olivier	5,952	5,280	3,016
Gregory B. Butler	5,052	4,242	2,232
James B. Robb	2,249	2,906	1,463

In all cases, NU reduces the distribution of common shares by that number of shares valued in an amount sufficient to satisfy tax withholding obligations, which amount NU distributes in cash. Included in the value realized are values associated with deferred RSUs, which are also reported in the Registrant Contributions in Last Fiscal Year column of the Non-Qualified Deferred Compensation Table.

(3)

Value realized on vesting of Mr. Robb s 2007 RSU grant is based on $29.48 per share, the closing price of common shares on September 3, 2010 and the associated third-quarter 2010 dividend equivalent units at $29.87 per share, the closing price of common shares on September 29, 2010. Value realized on vesting for all other amounts is based on $26.26 per share, the closing price of common shares on February 24, 2010. This value includes the value of vested RSUs for which the distribution of common shares is currently deferred.

PENSION BENEFITS IN 2010

The Pension Benefits Table sets forth the estimated present value of accumulated retirement benefits that would be payable to each Named Executive Officer upon his retirement as of the first date upon which he is eligible to receive an unreduced pension benefit (see below). The table distinguishes the benefits among those available through the Retirement Plan, the Supplemental Plan and any additional benefits available under the respective officer s employment agreement. The Supplemental Plan provides a make whole benefit that is based in part on compensation that is not permitted to be recognized under a tax-qualified plan and provides a target benefit if the eligible officer continues his or her employment until age 60. Benefits under the Supplemental Plan are also based on elements of compensation that are not included under the Retirement Plan. This includes compensation equal to: (i) deferred compensation; (ii) the value of awards under the Annual Incentive Program for officers; and (iii) long-term incentive awards only for Messrs. McHale and Butler (as to each of their respective make whole benefits), the values of which are frozen at the 2001 target levels.

The present value of accumulated benefits shown in the Pension Benefits Table was calculated as of December 31, 2010 assuming benefits would be paid in the form of a one-half spousal contingent annuitant option (the typical form of payment for the target benefit). For Mr. Olivier, who has a special retirement arrangement, NU assumed that his special retirement benefit would be paid as a lump sum, and his Retirement Plan benefit would be paid in the form of a life annuity with a one-third spousal contingent annuitant option (the typical form of payment under the Retirement Plan). None of Mr. Olivier s benefits will be provided under the Supplemental Plan. In addition, the present value of accrued benefits for any Named Executive Officer assumes that benefits commence at the earliest age at which the participant would be eligible to retire and receive unreduced benefits. Named Executive Officers are eligible to receive unreduced benefits upon the earlier of (a) attainment of age 65 or (b) attainment of at least age 55 when age plus service equals 85 or more years, except for Mr. Olivier. Mr. Olivier s unreduced benefit is available at age 60 pursuant to his employment agreement. The target benefit is available for Messrs. Butler and McHale only after age 60. Accordingly, Mr. Shivery is eligible to receive unreduced benefits at age 65, Messrs. McHale and Olivier are eligible to receive unreduced benefits at age 60, and Mr. Butler is eligible to receive unreduced benefits at age 62. Mr. Robb does not participate in the Retirement Plan or the Supplemental Plan.

The limitations applicable to the Retirement Plan under the Internal Revenue Code as of December 31, 2010 were used to determine the benefits under each plan. The accrued benefits reflect actual compensation (both salary and incentives) earned during 2010. Under the terms of the Supplemental Plan, annual incentives earned for services provided in a plan year are deemed to have been paid ratably over that plan year. For example, the March 2011 payment pursuant to the 2010 Annual Incentive Program was reflected in the 2010 plan compensation. NU determined the present value of the benefit at retirement age by using the discount rate of 5.57 percent under Statement of Financial Accounting Standards No. 87 for the 2010 fiscal year end measurement (as of December 31, 2010). This present value assumes no pre-retirement mortality, turnover or disability. However, for the postretirement period beginning at the retirement age, NU used the RP2000 Combined Healthy mortality table as published by the Society of Actuaries projected to 2011 with projection scale AA (same table used for financial reporting under FAS 87). Additional assumptions appear in Item 7 *Management s Discussion and Analysis and Results of Operations* in this Annual Report on Form 10-K.

Pension Benefits

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Charles W. Shivery (1)	Retirement Plan	8.6	327,627	
	Supplemental Plan	8.6	6,553,108	
	Other Special Benefit	11.6	2,405,851	
David R. McHale	Retirement Plan	29.3	732,032	
	Supplemental Plan	29.3	3,541,066	
Leon J. Olivier (2)	Retirement Plan	11.8	439,960	
	Supplemental Plan	9.3	—	
	Other Special Benefit	9.3	2,481,374	
	Other Special Benefit	31.3	1,253,081	105,966
Gregory B. Butler	Retirement Plan	14.0	344,191	
	Supplemental Plan	14.0	1,832,152	
James B. Robb	Retirement Plan			
	Supplemental Plan			

(1)

Mr. Shivery’s actual service with NU totaled 8.6 years at December 31, 2010. However, Mr. Shivery’s employment agreement provides for a special retirement benefit consisting of an amount equal to the difference between: (i) the equivalent of fully-vested benefits under the Retirement Plan and the Supplemental Plan calculated by adding three years to his actual service and using an early retirement commencement reduction factor of two percent per year for each year Mr. Shivery s age upon retirement is under age 65, if that factor yields a more favorable result to Mr. Shivery than the factors then in use under the Retirement Plan, and (ii) benefits otherwise payable from the Retirement Plan and the Supplemental Plan. The value of the additional three years of service on December 31, 2010 was approximately $2,405,851.

(2)

Mr. Olivier was employed with Northeast Nuclear Energy Company, one of NU s subsidiaries, from October of 1998 through March of 2001. In connection with this employment, he received a special retirement benefit that provided credit for service with his previous employer, Boston Edison Company (BECO), when calculating the value of his defined benefit pension, offset by the pension benefit provided by BECO. The benefit, which commenced upon Mr. Olivier s 55th birthday, provides an annuity of $105,966 per year in a form that provides no contingent annuitant benefit. The present value of future payments under this benefit was calculated using the actuarial assumptions currently used by the Retirement Plan. Mr. Olivier was rehired by NU from Entergy in September 2001. Mr. Olivier s current employment agreement provides for certain supplemental pension benefits in lieu of benefits under the Supplemental Plan, in order to provide a benefit similar to that provided by Entergy. Under this arrangement, if Mr. Olivier remains continuously employed by NU until September 10, 2011 (or terminates his employment earlier with NU s consent), he will be eligible to receive a special benefit, subject to reduction for termination prior to age 65, consisting of three percent of final average compensation for each of his first 15 years of service since September 10, 2001, plus one percent of final average compensation for each of the second 15 years of service. Alternatively, if Mr. Olivier voluntarily terminates his employment with NU after his 60th birthday, or NU terminates his employment earlier for any reason other than "cause" (as defined in his employment agreement, generally meaning willful and continued failure to perform his duties after written notice, a violation of NU s Standards of Business Conduct or conviction of a felony) he is eligible to receive upon retirement a lump sum payment of $2,050,000 in lieu of benefits under the Supplemental Plan and the benefit described in the preceding sentence. These supplemental pension benefits will be offset by the value of any benefits he receives from the Retirement Plan. Because Mr. Olivier attained age 60 during 2008, amounts reported in the table assume the termination of his employment on December 31, 2010, and payment of the lump sum benefit of $2,921,334, offset by Retirement Plan benefits.

NONQUALIFIED DEFERRED COMPENSATION IN 2010

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($) (2)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)(3)	Aggregate Balance at Last FYE ($) (4)
Charles W. Shivery	1,894,394	23,700	2,298,819	(83,334)	10,824,523
David R. McHale	8,400	8,400	76,104	(36,732)	354,500
Leon J. Olivier	110,000	9,150	214,768	(92,678)	1,902,186
Gregory B. Butler			114,262	(98,805)	521,013
James B. Robb	46,408	25,868	25,159		170,409

(1)

Includes deferrals by the Named Executive Officers under the 2010 Deferral Plan (Mr. Shivery: $31,050; Mr. McHale: $8,400; Mr. Olivier: 110,000; and Mr. Robb: $8,000). Named Executive Officers who participate in the Deferral Plan are provided with a variety of investment opportunities, which the individual can modify and reallocate at any time. Fund gains and losses are updated daily by NU s recordkeeper, Fidelity Investments. Contributions by the Named Executive Officer are vested at all times; however, the employer matching contribution vests after three years and will be forfeited if the executive s employment terminates, other than for retirement, prior to vesting.

All other amounts relate to the value of common shares, the distribution of which was either automatically deferred upon vesting of underlying RSUs pursuant to the terms of the respective Long-Term Incentive Programs, or pursuant to the Named Executive Officer s deferral election, calculated using $26.26 per share, the closing price of the common shares on February 24, 2010, the last trading day preceding the vesting date of February 25, 2010. For more information, see the footnotes to the Options Exercised and Stock Vested Table.

(2)

Includes employer matching contributions made to the Deferral Plan as of December 31, 2010 and posted on January 31, 2011, as reported in the All Other Compensation column of the Summary Compensation Table (Mr. Shivery: $23,700; Mr. McHale: $8,400; Mr. Olivier: $9,150; and Mr. Robb: $25,868). The employer matching contribution is deemed to be invested in common shares but is paid in cash at the time of distribution. Also includes nonqualified K-Vantage employer contributions made to the Deferral Plan during fiscal year 2010 (Mr. Robb: $21,218).

(3)

Includes distributions to Named Executive Officers under the Deferral Plan during fiscal year 2010 pursuant to their deferral elections (Mr. Olivier: $17,437); plus the value of previously vested deferred RSUs distributed in 2010, pursuant to the Named Executive Officer s deferral election, valued at distribution at $26.26 per share, the closing price of NU common shares on February 24, 2010.

(4)

Includes the total market value of Deferral Plan balances at December 31, 2010, plus the value of vested RSUs for which the distribution of common shares is currently deferred, based on $31.88 per share, the closing price of NU common shares on December 31, 2010.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

Generally, a "change of control" means a change in ownership or control of NU effected through (i) the acquisition of 20 percent or more of the combined voting power of common shares or other voting securities, (ii) a change in the majority of NU s Board of Trustees over a 24-month period, unless approved by a majority of the incumbent Trustees, (iii) certain reorganizations, mergers or consolidations where substantially all of the persons who were the beneficial owners of the outstanding NU common shares immediately prior to such business combination do not beneficially own more than 50 percent (75 percent for Messrs. Olivier and Robb) of the voting power of the resulting business entity, and (iv) complete liquidation or dissolution of NU, or a sale or disposition of all or substantially all of the assets of NU other than to an entity with respect to which following completion of the transaction more than 50 percent (75 percent for Messrs. Olivier and Robb) of common shares or other voting securities is then owned by all or substantially all of the persons who were the beneficial owners of common shares and other voting securities immediately prior to such transaction.

In the event of a change of control, the NEO s are each entitled to receive compensation and benefits following either termination of employment without "cause" or upon termination of employment by the executive for "good reason," within 24 months following the change of control. The Compensation Committee believes that termination for good reason is conceptually the same as termination "without cause" and, in the absence of this provision, potential acquirers would have an incentive to constructively terminate executives to avoid paying severance. Termination for "cause" generally means termination due to a felony conviction; acts of fraud, embezzlement, or theft in the course of employment; intentional, wrongful damage to company property; gross misconduct or gross negligence in the course of employment; or a material breach of obligations under the agreement. Termination for "good reason" generally is deemed to occur following an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement, a reduction in the compensation or benefits of the executive officer (a material reduction in compensation or benefits for Messrs. Olivier and Robb, or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control.

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With respect to the proposed merger with NSTAR, none of the Named Executive Officers will be entitled to receive any additional compensation and benefits in the absence of a termination of employment for cause or for good reason within two years after shareholder approval of the merger.

The discussion and tables below reflect the amount of compensation that would be payable to each of the Named Executive Officers in the event of: (i) termination of employment for cause; (ii) voluntary termination; (iii) involuntary not-for-cause termination (or voluntary termination for good reason); (iv) termination in the event of disability; (v) death; and (vi) termination following a change of control. The amounts shown assume that each termination was effective as of December 31, 2010, the last business day of the fiscal year as required under Securities and Exchange Commission reporting requirements.

Payments Upon Termination

Regardless of the manner in which the employment of a Named Executive Officer terminates, he is entitled to receive certain amounts earned during his term of employment. Such amounts include:

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Vested RSUs;

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Amounts contributed under the Deferral Plan;

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Vested matching contributions under the Deferral Plan;

.

Pay for unused vacation; and

.

Amounts accrued and vested through the Retirement Plan and the 401k Plan.

I.

Post-Employment Compensation: Termination for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Robb ($)
Incentive Programs					
Annual Incentives					
Performance Cash					
Performance Shares					
RSUs (1)	10,288,685	336,021	425,570	496,668	48,330
Pension and Deferred Compensation					
Supplemental Plan (2)	3,730,602				
Special Retirement Benefit (3)			1,610,040		
Deferral Plan (4)	535,838	9,462	1,476,616	24,345	102,906
Other Benefits					
Health and Welfare Cash Value					
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	14,555,125	345,483	3,512,226	521,013	151,236

(1)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2010, had been deferred upon vesting and remained deferred. Excludes retention pool RSU grants.

(2)

Represents the actuarial present value at the end of 2010 of the benefit payable from the Supplemental Plan to Mr. Shivery upon termination. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(3)

Represents the actuarial present values at the end of 2010 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,050,000 offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon termination. Pension amounts reflected in the table are present values at the end of 2010 of benefits payable to each NEO upon termination.

(4)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

II.

Post-Employment Compensation: Voluntary Termination

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Robb ($)
Incentive Programs					
Annual Incentives	1,987,200	608,517	601,494	458,320	339,000
Performance Cash (1)	4,486,734	427,500	759,313	347,975	228,000
Performance Shares (2)	2,620,237		331,742		
Performance Shares (3)	12,845,657	336,021	733,385	496,668	48,330
RSUs (4)					
Pension and Deferred Compensation					
Supplemental Plan (5)	6,553,109				
Special Retirement Benefit (6)	2,405,851		1,610,040		
Deferral Plan (7)	533,244	9,462	1,477,901	24,345	102,906
Other Benefits					
Health and Welfare Benefits (8)	101,181				
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	31,533,213	1,381,500	5,513,875	1,327,308	718,236

(1)

Represents the actual 20109 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" above.

(2)

Represents the actual performance cash award under the 2008 2010 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery and Olivier, prorated performance cash awards under the 2009 2011 and 2010 2012 Long-Term Incentive Programs, because each of them would be considered to be a "retiree" under those programs. Amounts are prorated for time worked in each three-year performance period, determined as described in the "Compensation Discussion and Analysis" above.

(3)

Includes, for Messrs. Shivery and Olivier, the prorated performance share award under the 2009 2011 and 2010 2012 Long-Term Incentive Programs, because each of them would be considered to be a "retiree" under those programs. Amounts are prorated for time worked in the three-year performance period, determined as described in the "Compensation Discussion and Analysis" above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs that, as of the end of 2010, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of each RSU grant, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. The values were calculated by multiplying the number of RSUs by $31.88, the closing price of NU common shares on December 31, 2010. Excludes retention pool RSU grants.

(5)

Represents the actuarial present value at the end of 2010 of the benefit payable from the Supplemental Plan to Mr. Shivery upon termination. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table above.

(6)

Represents the actuarial present values at the end of 2010 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon voluntary termination were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,748,997 offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon voluntary termination. Pension amounts reflected in the table are present values at the end of 2010 of benefits payable to each Named Executive Officer upon termination. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table above.

(7)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2010 of providing post-employment welfare benefits to Mr. Shivery beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. To the extent these benefits are provided in excess of those provided to employees in general, Mr. Shivery would receive payments to offset the taxes incurred on such benefits.

III.

Post-Employment Compensation: Involuntary Termination, Not for Cause

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Robb ($)
Incentive Programs					
Annual Incentives (1)	1,987,200	608,517	601,494	458,320	339,000
Performance Cash (2)	4,486,734	788,433	759,313	627,782	228,000
Performance Shares (3)	2,620,237	316,666	331,742	245,492	
RSUs (4)	12,845,657	965,689	2,266,080	923,469	470,148
Pension and Deferred Compensation					
Supplemental Plan (5)	6,553,109	2,979,143		1,312,808	
Special Retirement Benefit (6)	2,405,851	2,147,572	2,481,374	1,741,608	
Deferral Plan (7)	533,244	17,862	1,477,901	24,345	121,891
Other Benefits					
Health and Welfare Benefits (8)	101,181	65,269		65,923	
Perquisites (9)		7,000		7,000	
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement (10)		866,251		671,531	300,000
Separation Payment for Liquidated Damages (11)		866,251		671,531	300,000
Total	31,533,213	9,628,653	7,917,904	6,749,809	1,759,039

(1)

Represents the actual 2010 annual incentive award for each Named Executive Officer, determined as described in the "Compensation Discussion and Analysis" above.

(2)

Represents the actual performance cash award under the 2008 2010 Long-Term Incentive Program for each Named Executive Officer. Also includes, for Messrs. Shivery, McHale, Olivier and Butler, prorated performance cash awards under the 2009 2011 and 2010 2012 Long-Term Incentive Programs. Amounts are prorated for time worked in each three-year performance period, because each of them would be considered to be a "retiree" under those programs, determined as described in the "Compensation Discussion and Analysis" above.

(3)

Includes, for Messrs. Shivery, McHale, Olivier and Butler, a prorated performance share award under the 2009 2011 and 2010 2012 Long-Term Incentive Programs. Amounts are prorated for time worked in the three-year performance period, because each of them would be considered to be a "retiree" under those programs, determined as described in the "Compensation Discussion and Analysis" above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs and NU s retention program that, as of the end of 2010, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. Under NU s retention program, RSUs vest fully upon termination without cause of the Named Executive Officers and the value is reduced by any separation payments as described in footnotes 10 and 11.The values were calculated by multiplying the number of RSUs by $31.88, the closing price of NU common shares on December 31, 2010.

(5)

Represents the actuarial present value at the end of 2010 of the benefit payable from the Supplemental Plan to Mr. Shivery upon termination. The benefit is payable as an annuity, and the present value was calculated as described in notes 1 and 2 to the Pension Benefits Table appearing above.

(6)

Represents the actuarial present values at the end of 2010 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreements with Messrs. McHale and Butler, pension benefits available upon an involuntary termination other than for cause were calculated with the addition of two years of age and service. Pursuant to the employment agreement with Mr. Shivery, pension benefits were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,921,334, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon an involuntary termination other than for cause. Pension amounts reflected in the table are present values at the end of 2010 of benefits payable to each Named Executive Officer upon termination. Except for the benefit payable to Mr. Olivier, all benefits are annuities calculated as described in notes 1 and 2 to the Pension Benefits Table appearing above.

(7)

Represents the vested Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2010 of providing post-employment welfare benefits to the Named Executive Officers beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Each of Messrs. McHale and Butler is entitled to receive active health and welfare

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benefits and the cash value of company-paid active long-term disability and life insurance benefits for two years under the terms of his respective employment agreement, plus tax gross-up with respect to such taxable subsidized coverage and are eligible to receive qualified benefits under NU s retiree health plan. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. Therefore, the amount reported in the table for Messrs. McHale and Butler represents (a) the value of 24 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) tax gross-up payments thereon. The amount reported in the table for Mr. Shivery represents (a) the value of lifetime retiree health coverage, plus (b) tax gross-up payments thereon.

(9)

Represents the cost to NU of reimbursing fees for financial planning and tax preparation services to Messrs. McHale, and Butler for two years.

(10)

Represents payments made as consideration for agreements by each of Messrs. McHale, Butler, and Robb not to compete with the company following termination. Employment or other agreements with Messrs. McHale and Butler provide for a lump-sum payment in an amount equal to the sum of their 2010 annual salary plus annual incentive award at target, and one-half of the sum of 2009 annual salary plus annual incentive award at target (for Mr. Robb). These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(11)

Represents severance payments to Messrs. McHale, Butler and Robb paid in addition to the non-compete agreement payments described in note 10. This payment is an amount equal to the sum (one-half of the sum for Mr. Robb) of their actual base salary paid in 2010 (2009 for Mr. Robb) plus 2010 annual incentive award at target (2009 for Mr. Robb). These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

IV.

Post-Employment Compensation: Termination Upon Disability

<u>**Type of Payment**</u>	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					
Annual Incentives (1)	1,987,200	608,517	601,494	458,320	339,000

Performance Cash (2)	4,486,734	788,433	759,313	627,782	411,329
Performance Shares (3)	2,620,237	316,666	331,742	245,492	160,855
RSUs (4)	12,845,657	2,698,191	2,266,080	2,266,531	1,229,085
Pension and Deferred Compensation					
Supplemental Plan (5)	6,553,109	4,950,069		1,832,154	
Special Retirement Benefit (6)	2,405,851		2,481,374		
Deferral Plan (7)	533,244	17,862	1,477,901	24,345	121,891
Other Benefits					
Health and Welfare Benefits (8)	101,181				
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	31,533,213	9,379,738	7,917,904	5,454,624	2,262,160

(1)

Represents the actual 2010 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

(2)

Represents the actual performance cash award under the 2008 2010 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target under each of the 2009 2011 Long-Term Incentive Program and 2010 2012 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share award at target under the 2009 2011 and 2010 2012 Long-Term Incentive Programs prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs and NU s retention program that, as of the end of 2010, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination, and time worked during the vesting period. Under NU s retention program, RSUs vest fully upon termination on account of disability of the Named Executive Officer. The values were calculated by multiplying the number of RSUs by $31.88, the closing price of NU common shares on December 31, 2010.

(5)

Represents the actuarial present value at the end of 2010 of the benefit payable from the Supplemental Plan to each NEO other than Mr. Olivier. For purposes of valuing the pension benefits, NU has assumed that each Named Executive Officer would remain on NU s Long Term Disability plan until the executive s first unreduced combined pension benefit age. Therefore, the numbers shown represent the actuarial present values at the end of 2010 of nonqualified pension benefits payable to each Named Executive Officer, assuming termination of employment at the earliest unreduced benefit age. The earliest unreduced benefit ages are different for each NEO based on employment agreement provisions and years of service, as follows: Mr. Shivery: immediately; Mr. McHale: age 55; Mr. Olivier: immediately; and Mr. Butler: age 62. The benefit is payable as an annuity, and the present value was calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(6)

Represents the actuarial present values at the end of 2010 of the amounts payable to the Named Executive Officers under the assumptions discussed in note 5, solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon disability termination were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,921,334, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon disability termination. Mr. Shivery s benefit would be paid as an annuity calculated as described in notes 1 and 2 to the Pension Benefits Table appearing above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2010 of providing post-employment welfare benefits to Mr. Shivery beyond those benefits that would be provided to a nonexecutive employee upon disability termination. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. To the extent these benefits are provided in excess of those provided to employees in general, Mr. Shivery would receive payments to offset the taxes incurred on such benefits.

V.

Post-Employment Compensation: Death

Type of Payment	**Shivery ($)**	**McHale ($)**	**Olivier ($)**	**Butler ($)**	**Robb ($)**
Incentive Programs					

Annual Incentives (1)	1,987,200	608,517	601,494	458,320	339,000
Performance Cash (2)	4,486,734	788,433	759,313	627,782	411,329
Performance Shares (3)	2,620,237	316,666	331,742	245,492	160,855
RSUs (4)	12,845,657	2,698,191	2,266,080	2,266,531	1,229,085
Pension and Deferred Compensation					
Supplemental Plan (5)	3,313,827	5,407,021		738,452	
Special Retirement Benefit (6)	1,216,610		2,571,862		
Deferral Plan (7)	533,244	17,862	1,477,901	24,345	121,891
Other Benefits					
Health and Welfare Benefits (8)	60,235				
Perquisites					
Separation Payments					
Excise Tax & Gross-Up					
Separation Payment for Non-Compete Agreement					
Separation Payment for Liquidated Damages					
Total	27,063,744	9,836,690	8,008,392	4,360,922	2,262,160

(1)

Represents the actual 2010 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

(2)

Represents the actual performance cash award under the 2008 2010 Long-Term Incentive Program determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target under each of the 2009 2011 Long-Term Incentive Program and the 2010 2012 Long-Term Incentive Program prorated for time worked in each three-year performance period.

(3)

Represents the performance share award at target under the 2009 2011 and 2010 2012 Long-Term Incentive Programs prorated for time worked in the three-year performance period, as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs and NU s retention program that, as of the end of 2010, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of the long-term incentive programs, RSUs vest on a prorated basis based on the Named Executive Officers years of credited service and age as of termination upon death, and time worked during the vesting period. Under NU s retention program, RSUs vest fully upon termination on account of death of the Named Executive Officer. The values were calculated by multiplying the number of RSUs by $31.88, the closing price of NU common shares on December 31, 2010.

(5)

Represents the lump sum present value of pension payments from the Supplemental Plan to the surviving spouse of each Named Executive Officer. The benefits are payable as annuities, and the present values are calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(6)

Represents the actuarial present values at the end of 2010 of the amounts payable to the surviving spouses of the Named Executive Officers, solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon death were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,921,334, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier s spouse upon death. Pension amounts reflected in the table are present values at the end of 2010 of benefits payable immediately to each Named Executive Officer s surviving spouse. Mr. Shivery s benefit would be paid as an annuity calculated as described in Notes 1 and 2 to the Pension Benefits Table appearing above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2010 of providing post-employment welfare benefits to the Mr. Shivery s surviving spouse beyond those benefits that would be provided to a nonexecutive employee s spouse upon the employee s death. Mr. Shivery s surviving spouse is entitled to receive retiree health benefits under Mr. Shivery s employment agreement. To the extent these benefits are taxable to Mr. Shivery s surviving spouse, she would receive payments to offset the taxes incurred on such benefits.

Payments Made Upon a Change of Control

The employment or other agreements with Messrs. McHale, Olivier, Butler, and Robb include change of control benefits. Mr. Olivier participates in the SSP, which provides benefits upon termination of employment in connection with a change of control. The employment agreements and the SSP are binding on NU and on certain of NU s majority-owned subsidiaries, including CL&P. The terms of the various employment agreements are substantially similar, except for the agreement with Mr. Olivier, which refers instead to the change of control provisions of the SSP, and the agreement with Mr. Robb.

Pursuant to the employment or other agreements and under the terms of the SSP, if an executive officer s employment terminates following a change of control, other than termination of employment for "cause" (as defined in the employment agreements, generally meaning willful and continued failure to perform his duties after written notice, a violation of NU s Standards of Business Conduct or conviction of a felony), or by reason of death or disability), or if the executive officer terminates his or her employment for "good reason" (as defined in the employment agreements, generally meaning an assignment to duties inconsistent with his position, a failure by the employer to satisfy material terms of the agreement or the transfer of the executive to an office location more than 50 miles from his or her principal place of business immediately prior to a change of control), then the executive officer will receive the benefits listed below, which receipt is conditioned upon delivery of a binding release of all legal claims against the NU and its subsidiaries:

.

A lump sum severance payment of two-times (one-times for Mr. Olivier and one-half times for Mr. Robb) the sum of the executive s base salary plus all annual awards that would be payable for the relevant year determined at target (Base Compensation);

.

As consideration for a non-competition and non-solicitation covenant, a lump sum payment in an amount equal to the Base Compensation (one-half times Base Compensation for Mr. Robb);

.

Active health benefits continuation, provided for three years (two years for Mr. Olivier, none for Mr. Robb);

.

Benefits as if provided under the Supplemental Plan, notwithstanding eligibility requirements for the Target Benefit, including favorable actuarial reductions and the addition of three years to the executive s age and years of service as compared to benefits available upon voluntary termination of employment (except for Mr. Olivier, whose benefits are described below, and Mr. Robb, who does not participate in the Supplemental Plan);

.

Automatic vesting and distribution in respect of all unvested RSUs and all performance units at target; and

.

A lump sum payment in an amount equal to the excise tax charged to the executive under the Internal Revenue Code as a result of the receipt of any change of control payments, plus tax gross-up (except for Mr. Olivier and Mr. Robb).

The summaries of the employment agreements above do not purport to be complete and are qualified in their entirety by the actual terms and provisions of the employment agreements, copies of which have been filed as exhibits to this Annual Report on Form 10-K .

VI.

Post-Employment Compensation: Termination Following a Change of Control

Type of Payment	Shivery ($)	McHale ($)	Olivier ($)	Butler ($)	Robb ($)
Incentive Programs					
Annual Incentives (1)	1,987,200	608,517	601,494	458,320	339,000
Performance Cash (2)	4,486,734	1,116,550	1,103,064	882,154	577,987
Performance Shares (3)	2,620,237	664,557	696,193	515,186	337,573
RSUs (4)	12,845,657	974,757	1,064,198	980,290	791,210
Pension and Deferred Compensation					
Supplemental Plan (5)	6,553,109	1,355,288		611,833	
Special Retirement Benefit (6)	2,405,851	3,831,993	2,481,374	3,043,307	
Deferral Plan (7)	533,244	17,862	1,477,901	24,345	121,891
Other Benefits					
Health and Welfare Benefits (8)	101,181	98,890	20,053	86,064	
Perquisites (9)		8,500		8,500	
Separation Payments					
Excise Tax & Gross-Up (10)		4,001,955		2,767,501	
Separation Payment for Non-Compete Agreement (11)		866,251	907,501	671,531	300,000
Separation Payment for Liquidated Damages (12)		1,732,501	907,501	1,343,062	300,000
Total	31,533,213	15,277,621	9,259,279	11,392,093	2,767,661

(1)

Represents the actual 2010 annual incentive award for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above.

(2)

Represents the actual performance cash award under the 2008 2010 Long-Term Incentive Program for each Named Executive Officer, determined as described in the Compensation Discussion and Analysis above, plus performance cash awards at target for each Named Executive Officer under each of the 2009 2011 Long-Term Incentive Program and the 2010 2012 Long-Term Incentive Program.

(3)

Represents the performance share award at target for each Named Executive Officer under the 2009 2011 and 2010 2012 Long-Term Incentive Programs, determined as described in the Compensation Discussion and Analysis above.

(4)

Represents values of all RSUs granted to the Named Executive Officers under NU s long-term incentive programs and NU s retention program that, as of the end of 2010, had been deferred upon vesting and remained deferred, or that had not yet vested according to their program grant vesting schedules. Under the terms of the long-term incentive programs, RSUs vest fully on termination following a change of control. Under NU s retention program, RSUs vest fully upon termination without cause of the Named Executive Officers and the value is reduced by any separation payments as described in footnotes 11 and 12. For Messrs. McHale, Olivier, and Butler, retention pool RSU grants are fully eliminated when offset by separation payments. The values were calculated by multiplying the number of RSUs by $31.88, the closing price of NU common shares on December 31, 2010.

(5)

Represents the actuarial present value at the end of 2010 of the benefit payable from the Supplemental Plan to Messrs. Shivery, McHale, and Butler upon termination. The benefit is payable as an annuity, and the present value was calculated as described in notes 1 and 2 to the Pension Benefits Table appearing above.

(6)

Represents the actuarial present values at the end of 2010 of the amounts payable to the Named Executive Officers solely as the result of provisions in employment agreements, which are in addition to amounts payable by the Retirement Plan or the Supplemental Plan. Pursuant to the employment agreements with Messrs. McHale and Butler, pension benefits available upon termination following a Change of Control were calculated with the addition of three years of age and service. Pursuant to the employment agreement with Mr. Shivery, pension benefits available upon retirement were calculated with the addition of three years of service. Pursuant to the employment agreement with Mr. Butler, the value of the Supplemental Plan and Special Retirement Benefits will be paid as a single lump sum rather than as an annuity if his termination date occurs within two years following a change in control that qualifies under Section 1.409A of the Treasury Regulations. Pursuant to the employment agreement with Mr. Olivier, a lump sum payment of $2,921,334, offset by the value of benefits from the Retirement Plan, would be payable to Mr. Olivier upon termination following a Change in Control. Pension amounts reflected in the table are present values at the end of 2010 of benefits payable to each Named Executive Officer upon termination Except for the benefits payable to Messrs. Butler and Olivier, all benefits are annuities calculated as described in notes 1 and 2 to the Pension Benefits Table appearing above.

(7)

Represents the Deferral Plan account balance of each Named Executive Officer accrued as of the end of 2010.

(8)

Represents the costs to the company estimated by NU s benefits consultants as of the end of 2010 of providing post-employment welfare benefits to the Named Executive Officers beyond those benefits that would be provided to a nonexecutive employee upon involuntary termination. Each of Messrs. McHale and Butler is entitled to receive active health and welfare benefits and the cash value of company-paid active long-term disability and life insurance benefits for three years under the terms of his respective employment agreement, plus tax gross-up with respect to such taxable subsidized coverage and are eligible for qualified benefits under NU s retiree health plan. Mr. Olivier participates in the SSP and is eligible for two years of active health benefits continuation and is eligible for qualified benefits under NU s retiree health plan. Mr. Shivery is entitled to receive retiree health benefits under his employment agreement. Therefore, the amount reported in the table for Mr. McHale represents (a) the value of 36 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) tax gross-up payments thereon. The amount reported in the table for Mr. Butler represents (a) the value of 36 months of employer contributions toward active health, long-term disability, and life insurance benefits, plus (b) tax gross-up payments thereon, less (c) the value of 12 months of retiree health coverage at retiree rates. The amount reported in the table for Mr. Olivier represents (a) the value of 24 months of employer contributions toward active health benefits, plus (b) tax gross-up payments thereon, less (c) the value of 24 months of retiree health coverage at retiree rates. The amount reported in the table for Mr. Shivery represents (a) the value of lifetime retiree health coverage, plus (b) tax gross-up payments thereon.

(9)

Represents the cost of reimbursing fees for financial planning and tax preparation services to Messrs. McHale and Butler for three years.

(10)

Represents payments made to offset costs to Messrs. McHale and Butler associated with certain excise taxes under Section 280G of the Internal Revenue Code. Employees may be subject to certain excise taxes under Section 280G if they receive payments and benefits related to a termination following a Change of Control that exceed specified Internal Revenue Service limits. Employment agreements with each Named Executive Officer except Mr. Olivier and Mr. Robb provide for a grossed-up reimbursement of these excise taxes. The amounts in the table are based on the Section 280G excise tax rate of 20 percent, the statutory federal income tax withholding rate of 35 percent, the Connecticut state income tax rate of 6.5 percent, and the Medicare tax rate of 1.45 percent.

(11)

Represents payments made as consideration for each Named Executive Officer s agreement not to compete with the company following termination of employment. This payment equals the sum (one-half of the sum for Mr. Robb) of the actual base salary paid in 2010 (2009 for Mr. Robb) plus annual incentive award at target. Agreements with each Named Executive Officer provide for a lump-sum payment equal to their annual salary plus their annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

(12)

Represents severance payments to each Named Executive Officer paid in addition to the non-compete agreement payments described in note (11). For Messrs. McHale, and Butler, this payment equals two-times the sum of the actual base salary paid in 2010 plus annual incentive award at target. For Mr. Olivier, this payment equals the sum of the actual base salary paid in 2010 plus annual incentive award at target. For Mr. Robb this payment equals one-half of the sums of his actual base salary paid in 2009 plus annual incentive award at target. These payments do not replace, offset or otherwise affect the calculation or payment of the annual incentive awards.

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

NU

In addition to the information below under "Securities Authorized for Issuance Under Equity Compensation Plans," incorporated herein by reference is the information contained in the sections "Common Share Ownership of Certain Beneficial Owners" and "Common Share Ownership of Trustees and Management" of NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 30, 2011.

PSNH and WMECO

Certain information required by this Item 12 has been omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries.

CL&P

NU owns 100 percent of the outstanding common stock of CL&P. The following table sets forth, as of February 22, 2011, the beneficial ownership of the equity securities of NU by (i) the Chief Executive Officer of CL&P and the executive officers of CL&P listed on the Summary Compensation Table in Item 11 and (ii) all of the current executive officers and directors of CL&P, as a group. No equity securities of CL&P are owned by any of the directors or executive officers of CL&P.

	Amount and Nature of Beneficial Ownership (1)				
	NU Common Shares	**Options (2)**	**Total**	**Percent of Class**	**Restricted Share Units (3)**
Leon J. Olivier, CEO, Director (5)	32,895	-	32,895	*	91,120
David R. McHale, CFO, Director (5)(7)	35,790	-	35,790	*	101,674
Gregory B. Butler, Senior Vice President and General Counsel, Director (4)(5)(6)	47,955	-	47,956	*	84,399
James B. Robb, Director (5)	8,668	-	8,668	*	47,774
Charles W. Shivery, Chairman, Director (5)(8)	54,350	29,024	83,374	*	512,518
All directors and Executive Officers as a Group (7 persons)	199,800	29,024	227,007	*	859,267

*Less than 1 percent of common shares outstanding.

(1)

The persons named in the table have sole voting and investment power with respect to all shares beneficially owned by each of them, except as note below.

(2)

Reflects common shares issuable upon exercise of outstanding stock options exercisable within the 60-day period after February 22, 2011.

(3)

Includes unissued common shares consisting of performance shares restricted share units, deferred restricted share units and/or deferred shares, including dividend equivalents, as to which none of the individuals has voting or investment power. Also includes phantom common shares, representing employer matching contributions distributable only in cash, held by executive officers who participate in our Deferred Compensation Plan for Executives. Accordingly, these securities have been excluded from the "Total" column.

(4)

Includes 44,251 shares owned jointly by Mr. Butler and his spouse with whom he shares voting and investment power.

(5)

Includes common shares held in the 401(k) Plan in the employer stock ownership plan account over which the holder has sole voting and investment power (Mr. Butler: 3,264 shares; Mr. McHale: 3,967 shares; Mr. Olivier: 1,887 shares; Mr. Robb: 649 shares; and Mr. Shivery: 2,021 shares).

(6)

Includes common shares held as units in the 401(k) Plan invested in the NU Common Shares Fund over which the holder has sole voting and investment power (Mr. Butler: 439 shares; and Mr. McHale: 1,817 shares).

(7)

Includes 112 shares held by Mr. McHale in the 401(k) Plan TRAESOP/PAYSOP account over which Mr. McHale has sole voting and investment power.

(8)

Includes 1,500 shares owned jointly by Mr. Shivery and his spouse with whom he shares voting and investment power.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth the number of NU common shares issuable under NU equity compensation plans, as well as their weighted exercise price, as of December 31, 2010, in accordance with the rules of the SEC:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
		$	
Equity compensation plans approved by security holders	1,375,637	18.80	4,001,028
Equity compensation plans not approved by	-	-	-

security holders (d)			
Total	1,375,637	$ 18.80	4,001,028

(a)

Includes 112,599 common shares to be issued upon exercise of options, 1,014,479 common shares for distribution of restricted share units, and 248,559 performance shares issuable at target, all pursuant to the terms of our Incentive Plan.

(b)

The weighted-average exercise price in Column (b) does not take into account restricted share units or performance shares, which have no exercise price.

(c)

Includes 932,178 common shares issuable under our Employee Share Purchase Plan II.

(d)

All of our current compensation plans under which equity securities of NU are authorized for issuance have been approved by NU s shareholders.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

NU

Incorporated herein by reference is the information contained in the sections captioned "Trustee Independence" and "Certain Relationships and Related Transactions" of NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 30, 2011.

PSNH and WMECO

Certain information required by this Item 13 has been omitted for PSNH and WMECO pursuant to Instruction I(2)(c) to Form 10-K, Omission of Information by Certain Wholly-Owned Subsidiaries**.**

CL&P

NU s Code of Ethics for Senior Financial Officers applies to the Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller) of CL&P and certain other NU subsidiaries. Under the Code, one s position as a Senior Financial Officer in the company may not be used to improperly benefit such officer or his or her family or friends. Under the Code, specific activities that may be considered conflicts of interest include, but are not limited to, directly or indirectly acquiring or retaining a significant financial interest in an organization that is a customer, vendor or competitor, or that seeks to do business with the company; serving, without proper safeguards, as an officer or director of, or working or rendering services for an organization that is a customer, vendor or competitor, or that seeks to do business with the company. Waivers of the provisions of the Code of Ethics for Trustees, executive officers or directors must be approved by NU s Board of Trustees. Any such Waivers will be disclosed pursuant to legal requirements.

NU s Standards of Business Conduct, which applies to all Trustees, directors, officers and employees of NU and its subsidiaries, including CL&P, contains a Conflict of Interest Policy that requires all such individuals to disclose any potential conflicts of interest. Such individuals are expected to discuss their particular situations with management to ensure appropriate steps are in place to avoid a conflict of interest. All disclosures must be reviewed and approved by management to ensure a particular situation does not adversely impact the individual s primary job and role.

NU s Related Party Transactions Policy is administered by the Corporate Governance Committee of NU s Board of Trustees. The Policy generally defines a "Related Party Transaction" as any transaction or series of transactions in which (i) NU or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any "Related Party" has a direct or indirect material interest. A "Related Party" is defined as any Trustee or nominee for Trustee, any executive officer, any shareholder owning more than 5 percent of NU's total outstanding shares, and any immediate family member of any such person. Management submits to the Corporate Governance Committee for consideration any Related Party Transaction into which NU or a subsidiary proposes to enter. The Corporate Governance Committee recommends to the NU Board of Trustees for approval only those transactions that are in NU s best interests. If management causes the company to enter into a Related Party Transaction prior to approval by the Corporate Governance Committee, the transaction will be subject to ratification by the NU Board of Trustees. If the NU Board of Trustees determines not to ratify the transaction, then management will make all reasonable efforts to cancel or annul such transaction.

The directors of CL&P are employees of CL&P and/or other subsidiaries of NU and thus are not considered independent.

Item 14.

Principal Accountant Fees and Services

NU

Incorporated herein by reference is the information contained in the section "Relationship with Independent Auditors" of NU s definitive proxy statement for solicitation of proxies, expected to be filed with the SEC on or about March 30, 2011.

CL&P, PSNH and WMECO

Pre-Approval of Services Provided by Principal Auditors

None of CL&P, PSNH or WMECO is subject to the audit committee requirements of the SEC, the national securities exchanges or the national securities associations. CL&P, PSNH and WMECO obtain audit services from the independent auditor engaged by the Audit Committee of NU s Board of Trustees. NU s Audit Committee has established policies and procedures regarding the pre-approval of services provided by the principal auditors. Those policies and procedures delegate pre-approval of services to the NU Audit Committee Chair and/or Vice Chair provided that such offices are held by Trustees who are "independent" within the meaning of the Sarbanes-Oxley Act of 2002 and that all such pre-approvals are presented to the NU Audit Committee at the next regularly scheduled meeting of the Committee.

The following relates to fees and services for the entire NU system, including NU, CL&P, PSNH and WMECO.

Fees Paid to Principal Auditor

NU and its subsidiaries paid Deloitte & Touche LLP fees aggregating $3,697,371 and $2,727,410 for the years ended December 31, 2010 and 2009, respectively, comprised of the following:

1.

Audit Fees

The aggregate fees billed to NU and its subsidiaries by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu and their respective affiliates (collectively, the Deloitte Entities), for audit services rendered for the years ended December 31, 2010 and 2009 totaled $2,713,150 and $2,636,775, respectively. The audit fees were incurred for audits of NU s annual consolidated financial statements and those of its subsidiaries, reviews of financial statements included in NU s Quarterly Reports on Form 10-Q and those of its subsidiaries, comfort letters, consents and other costs related to registration statements and financings. Audit fees in 2010 also included consents and other procedures related to a well-known seasoned issuer registration statement on Form S-3 and NU s registration statement on Form S-4 filed to registered common shares to be issued in the proposed merger with NSTAR. The fees also included audits of internal controls over financial reporting as of December 31, 2010 and 2009, as well as auditing the implementation of new accounting standards and the accounting for new contracts and proposed transactions.

2.

Audit Related Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2010 and 2009 totaled $480,186 and $66,000, respectively. Audit related fees in 2010 related to advisory services in connection with the preliminary readiness assessment for IFRS ($40,000) and accounting and tax due diligence procedures related to the proposed merger with NSTAR ($396,186). Audit related fees in 2010 and 2009 were also related to the examination of management s assertions about the securitization subsidiaries of CL&P, PSNH and WMECO.

3.

Tax Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for tax services for the years ended December 31, 2010 and 2009 totaled $52,535 and $23,135, respectively. These services related primarily to the reviews of tax returns and reviewing the tax impacts of proposed transactions in 2010 and 2009, plus tax advice on the partnership agreement for NPT, the related TSA and certain transmission asset sales agreements in 2010.

4.

All Other Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for services other than the services described above for the years ended December 31, 2010 and 2009 totaled $451,500 and $1,500, respectively. All other fees in 2010 consisted primarily of advisory services related to the Company's consideration of a business for enterprise resource planning. All other fees in 2010 and 2009 also included a license fee for access to an accounting research tool.

The Audit Committee of NU s Board of Trustees pre-approves all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed for NU and its subsidiaries by the independent auditors, subject to the de minimis exceptions for non-audit services described in Section 10A(i)(1)(B) of the Securities Exchange Act of 1934, which are approved by the Audit Committee prior to the completion of the audit. The Audit Committee may form and delegate its authority to subcommittees consisting of one or more members when appropriate, including the authority to grant pre-approvals of audit and permitted non-audit services, provided that decisions of such subcommittee to grant pre-approvals are presented to the full Audit Committee at its next scheduled meeting. During 2010, all services described above were pre-approved by the Audit Committee.

The Audit Committee has considered whether the provision by the Deloitte Entities of the non-audit services described above was allowed under Rule 2-01(c)(4) of Regulation S-X and was compatible with maintaining auditor independence and has concluded that the Deloitte Entities were and are independent of NU and its subsidiaries in all respects.

PART IV

Item 15.

Exhibits and Financial Statement Schedules

(a) 1. Financial Statements:

The financial statements filed as part of this Annual Report on Form 10-K are set forth under Item 8, "Financial Statements and Supplementary Data." Reference is made to the index on page 72.

2. Schedules

I.	Financial Information of Registrant: Northeast Utilities (Parent) Balance Sheets as of December 31, 2010 and 2009	S-1
	Northeast Utilities (Parent) Statements of Income for the Years Ended December 31, 2010, 2009 and 2008	S-2
	Northeast Utilities (Parent) Statements of Cash Flows for the Years Ended December 31, 2010, 2009 and 2008	S-3
II.	Valuation and Qualifying Accounts and Reserves for NU, CL&P, PSNH and WMECO for 2010, 2009 and 2008	S-4

All other schedules of the companies for which inclusion is required in the applicable regulations of the SEC are permitted to be omitted under the related instructions or are not applicable, and therefore have been omitted.

3.	Exhibit Index	E-1

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NORTHEAST UTILITIES

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHEAST UTILITIES
(Registrant)

By	/s/	Date
	Charles W. Shivery Charles W. Shivery Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Charles W. Shivery Charles W. Shivery	Chairman of the Board, President and Chief Executive Officer, and a Trustee (Principal Executive Officer)	February 25, 2011
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2011

/s/ Jay S. Buth Jay S. Buth	Vice President - Accounting and Controller	February 25, 2011
/s/ Richard H. Booth Richard H. Booth	Trustee	February 25, 2011
/s/ John S. Clarkeson John S. Clarkeson	Trustee	February 25, 2011
/s/ Cotton M. Cleveland Cotton M. Cleveland	Trustee	February 25, 2011
/s/ Sanford Cloud, Jr. Sanford Cloud, Jr.	Trustee	February 25, 2011
/s/ John F. Swope John F. Swope	Trustee	February 25, 2011
/s/ Robert E. Patricelli Robert E. Patricelli	Trustee	February 25, 2011
/s/ John G. Graham John G. Graham	Trustee	February 25, 2011
/s/ Elizabeth T. Kennan	Trustee	February 25, 2011

Elizabeth T. Kennan

/s/	Trustee	February 25, 2011
Kenneth R. Leibler Kenneth R. Leibler		
/s/	Trustee	February 25, 2011
Dennis R. Wraase Dennis R. Wraase		

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

By	/s/	Date
	Leon J. Olivier Leon J. Olivier Chief Executive Officer (Principal Executive Officer)	February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/	Chairman and a Director	February 25, 2011
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 25, 2011
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 25, 2011

Jeffrey D. Butler Jeffrey D. Butler	and a Director	
/s/ David R. McHale David R. McHale	Executive Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	February 25, 2011
/s/ Gregory B. Butler Gregory B. Butler	Director	February 25, 2011
/s/ Jean M. LaVechhia Jean M. LaVecchia	Director	February 25, 2011
/s/ James B. Robb James B. Robb	Director	February 25, 2011
/s/ Jay S. Buth Jay S. Buth	Vice President - Accounting and Controller	February 25, 2011

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
(Registrant)

By	/s/	Date
	Leon J. Olivier Leon J. Olivier Chief Executive Officer (Principal Executive Officer)	February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/	Chairman and a Director	February 25, 2011
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 25, 2011
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 25, 2011

Gary A. Long Gary A. Long	and a Director	
/s/	Executive Vice President and Chief Financial	February 25, 2011
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 25, 2011
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 25, 2011
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 25, 2011
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 25, 2011
Jay S. Buth Jay S. Buth		

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
(Registrant)

By	/s/	Date
	Leon J. Olivier Leon J. Olivier Chief Executive Officer (Principal Executive Officer)	February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/	Chairman and a Director	February 25, 2011
Charles W. Shivery Charles W. Shivery		
/s/	Chief Executive Officer and a Director	February 25, 2011
Leon J. Olivier Leon J. Olivier	(Principal Executive Officer)	
/s/	President and Chief Operating Officer	February 25, 2011

Peter J. Clarke Peter J. Clarke	and a Director	
/s/	Executive Vice President and Chief Financial	February 25, 2011
David R. McHale David R. McHale	Officer and a Director (Principal Financial Officer)	
/s/	Director	February 25, 2011
Gregory B. Butler Gregory B. Butler		
/s/	Director	February 25, 2011
Jean M. LaVecchia Jean M. LaVecchia		
/s/	Director	February 25, 2011
James B. Robb James B. Robb		
/s/	Vice President - Accounting and Controller	February 25, 2011
Jay S. Buth Jay S. Buth		

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AS OF DECEMBER 31, 2010 AND 2009
(Thousands of Dollars)

	2010	2009
ASSETS		
Current Assets:		
Cash	$ 268	$ 1,222
Notes Receivable from Affiliated Companies	132,600	186,213
Accounts Receivable	2,885	3,150
Accounts Receivable from Affiliated Companies	1,163	1,689
Taxes Receivable	18,139	2,838
Prepayments and Other Current Assets	18,021	6,837
Total Current Assets	173,076	201,949
Deferred Debits and Other Assets:		
Investments in Subsidiary Companies, at Equity	4,323,455	3,928,090
Notes Receivable from Affiliated Companies	62,500	62,500
Accumulated Deferred Income Taxes	23,288	31,503
Derivative Assets	4,099	6,520
Other Long-Term Assets	8,179	16,971
Total Deferred Debits and Other Assets	4,421,521	4,045,584
Total Assets	$ 4,594,597	$ 4,247,533
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 237,000	$ 100,313
Accounts Payable	179	-
Accounts Payable to Affiliated Companies	411	-
Accrued Taxes	3,616	1,162
Accrued Interest	8,024	6,112

Other	1,145	408
Total Current Liabilities	250,375	107,995
Deferred Credits and Other Liabilities:		
Other	6,776	35,442
Total Deferred Credits and Other Liabilities	6,776	35,442
Capitalization:		
Long-Term Debt	524,813	526,194
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	4,337,446	4,104,096
Total Liabilities and Capitalization	$ 4,594,597	$ 4,247,533

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008
(Thousands of Dollars, Except Share Information)

	2010	2009	2008
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	21,081	3,251	53,484
Operating Loss	(21,081)	(3,251)	(53,484)
Interest Expense	12,058	29,678	30,893
Other Income, Net:			
Equity in Earnings of Subsidiaries	396,333	346,137	307,908
Other, Net	4,536	6,511	6,956
Other Income, Net	400,869	352,648	314,864
Income Before Income Tax Benefit	367,730	319,719	230,487
Income Tax Benefit	(20,276)	(10,314)	(30,341)
Net Income	388,006	330,033	260,828
Net Income Attributable to Noncontrolling Interest	57	-	-
Net Income Attributable to Controlling Interest	$ 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

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SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008
(Thousands of Dollars)

	2010	2009	2008
Operating Activities:			
	$	$	$
Net Income	388,006	330,033	260,828
Adjustments to Reconcile Net Income to Net Cash			
Flows Provided by Operating Activities:			
Equity in Earnings of Subsidiaries	(396,333)	(346,137)	(307,908)
Cash Dividends Received from Subsidiaries	309,669	207,877	215,162
Deferred Income Taxes	8,398	(6,658)	(3,164)
Other	23,675	15,525	12,576
Changes in Current Assets and Liabilities:			
Receivables, Including Affiliate Receivables	791	(861)	883
Accounts Payable, Including Affiliate Payables	590	(35,522)	33,752
Taxes Receivable/Accrued	(28,394)	5,591	3,580
Other Current Assets and Liabilities	(12,656)	2,369	2,451
Net Cash Flows Provided by Operating Activities	293,746	172,217	218,160
Investing Activities:			
Capital Contributions to Subsidiaries	(313,560)	(243,688)	(323,164)
Return of Investment in Subsidiaries	5,000	-	30,000
Decrease/(Increase) in NU Money Pool Lending	83,300	128,700	(84,600)
Increase in Notes Receivable from Affiliated Companies	(29,687)	(72,709)	(79,504)
Other Investing Activities	1,703	2,283	1,557
Net Cash Flows Used in Investing Activities	(253,244)	(185,414)	(455,711)
Financing Activities:			
Issuance of Common Shares	-	383,295	-
Cash Dividends on Common Shares	(180,542)	(162,381)	(129,077)
Increase/(Decrease) in Short-Term Debt	136,687	(203,206)	261,519
Issuance of Long-Term Debt	-	-	250,000
Retirements of Long-Term Debt	-	-	(150,000)
Financing Fees	-	(12,457)	-

Other Financing Activities	2,399	7,874	6,109
Net Cash Flows (Used in)/Provided by Financing Activities	(41,456)	13,125	238,551
Net (Decrease)/Increase in Cash	(954)	(72)	1,000
Cash - Beginning of Year	1,222	1,294	294
Cash - End of Year	$ 268	$ 1,222	$ 1,294
Supplemental Cash Flow Information:			
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 22,886	$ 26,744	$ 27,522
Income Taxes	$ 1,291	$ (12,848)	$ (37,063)

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SCHEDULE II

NORTHEAST UTILITIES AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008

(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description:	Balance as of Beginning of Year	(1) Charged to Costs and Expenses	(2) Charged to Other Accounts - Describe (a)	Deductions - Describe (b)	Balance as of End of Year
NU:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					
2010	$ 55,300	$ 31,352	$ 10,714	$ 57,569	$ 39,797
2009	43,275	53,947	24,136	66,058	55,300
2008	25,529	28,573	81,991	92,818	43,275
CL&P:					
Reserves Deducted from Assets - Reserves for Uncollectible Accounts:					