

CONNECTICUT LIGHT & POWER CO
Form 10-Q
November 06, 2009

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

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended September 30, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

<u>Commission File Number</u>	<u>Registrant; State of Incorporation; Address; and Telephone Number</u>	<u>I.R.S. Employer Identification No.</u>
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 **PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** 02-0181050
(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

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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 whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes

No

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

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

<u>Company - Class of Stock</u>	<u>Outstanding at October 31, 2009</u>
Northeast Utilities Common shares, \$5.00 par value	175,463,545 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

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.

Public Service Company of New Hampshire and Western Massachusetts Electric Company each meet the conditions set forth in General Instructions H(1)(a) and (b) of Form 10-Q, and each is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) of Form 10-Q.

GLOSSARY OF TERMS

The following is a glossary of frequently used 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	Holyoke Water Power Company
NAESCO	North Atlantic Energy Service Corporation
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the Company	Northeast Utilities and subsidiaries
NU Enterprises	NU Enterprises, Inc. is the parent company of Select Energy, NGS, SECI and Boulos. For further information, see Note 11, "Segment Information," to the unaudited condensed consolidated financial statements.
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, The Rocky River Realty Company (a real estate subsidiary), Mode 1 Communications, Inc. (telecommunications) 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 segment of PSNH, and Yankee Gas, a natural gas local distribution company. For further information, see Note 11, "Segment Information," to the unaudited condensed consolidated financial statements.
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

DOE	U.S. Department of Energy
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER:

2008 Form 10-K	The Northeast Utilities and subsidiaries combined 2008 Annual Report on Form 10-K as filed with the SEC
AFUDC	Allowance For Funds Used During Construction
C&LM	Conservation and Load Management
CfD	Contract for Differences
CTA	Competitive Transition Assessment
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Charge
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge
GWh	Gigawatt Hours
IPP	Independent Power Producers
ISO-NE	New England Independent System Operator or ISO New England, Inc.
kWh	Kilowatt-Hours
KV	Kilovolt
LBCB	Lehman Brothers Commercial Bank, Inc.
LOC	Letter of Credit
Money Pool	Northeast Utilities Money Pool
MW	Megawatts
MWh	Megawatt-Hours
NEEWS	New England East-West Solutions
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NYMPA	New York Municipal Power Agency
PBOP	Postretirement Benefits Other Than Pension
PCRBs	Pollution Control Revenue Bonds
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.
ROE	Return on Equity
RRB	Rate Reduction Bonds
SBC	Systems Benefit Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan

TCAM

Transmission Cost Adjustment Mechanism

UI

The United Illuminating Company

**NORTHEAST UTILITIES AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES
WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY**

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NORTHEAST UTILITIES AND SUBSIDIARIES

NORTHEAST UTILITIES AND SUBSIDIARIES
 CONDENSED CONSOLIDATED BALANCE
 SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>ASSETS</u>		
Current Assets:		
Cash and cash equivalents	\$ 248,977	\$ 89,816
Receivables, less provision for uncollectible accounts of \$52,305 in 2009 and \$43,275 in 2008	591,469	698,755
Unbilled revenues	164,472	218,440
Fuel, materials and supplies - current	281,409	300,049
Marketable securities - current	63,887	78,452
Derivative assets - current	19,270	31,373
Prepayments and other	110,121	88,679
	1,479,605	1,505,564
Property, Plant and Equipment:		
Electric utility	9,563,493	9,219,351
Gas utility	1,070,950	1,043,687
Other	288,918	290,156
	10,923,361	10,553,194
Less: Accumulated depreciation: \$2,731,763 for electric and gas utility and \$129,755 for other in 2009; \$2,610,479 for electric and gas utility and \$159,639 for other in 2008	2,861,518	2,770,118
	8,061,843	7,783,076
Construction work in progress	561,218	424,800
	8,623,061	8,207,876

Deferred Debits and Other Assets:

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Regulatory assets	3,170,566	3,502,606
Goodwill	287,591	287,591
Marketable securities - long-term	55,351	30,757
Derivative assets - long-term	217,780	241,814
Other	172,380	212,272
	3,903,668	4,275,040

Total Assets	\$ 14,006,334	\$ 13,988,480
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
 CONDENSED CONSOLIDATED BALANCE
 SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to banks	\$ 325,234	\$ 618,897
Long-term debt - current portion	66,286	54,286
Accounts payable	410,125	678,614
Accrued taxes	73,802	12,527
Accrued interest	89,165	69,818
Derivative liabilities - current	56,811	100,919
Other	173,167	168,401
	1,194,590	1,703,462
Rate Reduction Bonds	503,303	686,511
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,338,979	1,223,461
Accumulated deferred investment tax credits	22,952	25,371
Deferred contractual obligations	173,451	193,016
Regulatory liabilities	529,259	592,540
Derivative liabilities - long-term	858,306	912,426
Accrued pension	740,421	740,930
Accrued postretirement benefits	224,039	240,371
Other	426,388	430,718
	4,313,795	4,358,833
Capitalization:		
Long-Term Debt	4,345,028	4,103,162

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Noncontrolling Interest in Consolidated
Subsidiary:

Preferred stock not subject to mandatory redemption	116,200	116,200
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Common Shareholders' Equity:

Common shares, \$5 par value - authorized 225,000,000 shares; 195,400,618 shares issued and 175,435,375 shares outstanding in 2009 and 176,212,275 shares issued and 155,834,361 shares outstanding in 2008	977,003	881,061
Capital surplus, paid in	1,758,109	1,475,006
Deferred contribution plan - employee stock ownership plan	(5,927)	(15,481)
Retained earnings	1,203,603	1,078,594
Accumulated other comprehensive loss	(37,767)	(37,265)
Treasury stock, 19,708,136 shares in 2009 and 2008	(361,603)	(361,603)
Common Shareholders' Equity	3,533,418	3,020,312
Total Capitalization	7,994,646	7,239,674

Total Liabilities and Capitalization	\$ 14,006,334	\$ 13,988,480
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

NORTHEAST UTILITIES AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF INCOME
 (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of Dollars, except share information)	2009	2008	2009	2008
		\$	\$	\$
Operating Revenues	\$ 1,306,173	1,506,897	4,124,087	4,352,209
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	611,632	801,050	2,034,151	2,286,066
Other	250,296	232,222	732,562	755,306
Maintenance	61,609	71,287	166,812	198,892
Depreciation	77,074	69,717	231,825	205,792
Amortization of regulatory assets, net	10,542	61,386	19,194	132,186
Amortization of rate reduction bonds	56,669	53,132	163,871	154,366
Taxes other than income taxes	75,798	69,026	216,651	200,133
Total operating expenses	1,143,620	1,357,820	3,565,066	3,932,741
Operating Income	162,553	149,077	559,021	419,468
Interest Expense:				
Interest on long-term debt	55,733	53,111	168,191	142,333
Interest on rate reduction bonds	8,657	12,207	28,889	38,910
Other interest	5,245	5,579	8,490	18,355
Interest expense, net	69,635	70,897	205,570	199,598

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Other Income, Net	9,490	17,682	26,081	41,610
Income Before Income Tax Expense				
Tax Expense	102,408	95,862	379,532	261,480
Income Tax Expense	36,230	21,783	130,047	68,381
Net Income	66,178	74,079	249,485	193,099
Net Income Attributable to Noncontrolling Interest:				
Preferred dividends of subsidiary	1,390	1,390	4,169	4,169
Net Income Attributable to Controlling Interest	\$ 64,788	\$ 72,689	\$ 245,316	\$ 188,930
Basic Earnings Per Common Share	\$ 0.37	\$ 0.47	\$ 1.43	\$ 1.22
Fully Diluted Earnings Per Common Share	\$ 0.37	\$ 0.47	\$ 1.43	\$ 1.21
Dividends Declared Per Common Share	\$ 0.24	\$ 0.21	\$ 0.71	\$ 0.61
Weighted Average Common Shares Outstanding:				
Basic	175,358,776	155,607,201	170,958,396	155,456,606
Fully Diluted	175,995,506	156,097,641	171,532,913	155,904,871

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

NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS
OF CASH FLOWS

(Unaudited)

(Thousands of Dollars)	Nine Months Ended September 30,	
	2009	2008
Operating Activities:		
Net income	\$ 249,485	\$ 193,099
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Bad debt expense	31,519	21,341
Depreciation	231,825	205,792
Deferred income taxes	77,617	31,125
Pension and PBOP expense/(income), net of capitalized portion, and contributions	10,197	(12,642)
Allowance for equity funds used during construction	(6,162)	(23,546)
Regulatory overrecoveries/(refunds and underrecoveries), net	42,677	(97,888)
Amortization/(deferral) of recoverable energy costs	1,842	(5,898)
Amortization of regulatory assets, net	19,194	132,186
Amortization of rate reduction bonds	163,871	154,366
Deferred contractual obligations	(20,816)	(25,604)
Derivative assets and liabilities	(18,519)	(32,369)
Other	13,493	(2,796)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	122,700	(10,356)
Investments in securitizable assets	-	(25,787)
Fuel, materials and supplies	18,900	(59,554)
Other current assets	(7,490)	(18,962)
Taxes receivable/accrued	59,641	64,425
Accounts payable	(242,179)	(58,594)
Other current liabilities	13,335	(2,063)
Net cash flows provided by operating activities	761,130	426,275

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Investing Activities:

Investments in property and plant	(634,446)	(951,831)
Proceeds from sales of marketable securities	182,131	195,445
Purchases of marketable securities	(183,814)	(197,453)
Other investing activities	4,298	3,230
Net cash flows used in investing activities	(631,831)	(950,609)

Financing Activities:

Issuance of common shares	388,529	5,002
Cash dividends on common shares	(120,647)	(95,824)
Cash dividends on preferred stock of subsidiary	(4,169)	(4,169)
(Decrease)/increase in short-term debt	(293,663)	363,187
Issuance of long-term debt	312,000	660,000
Retirements of long-term debt	(54,286)	(154,286)
Retirements of rate reduction bonds	(183,208)	(174,091)
Financing fees	(15,331)	(6,234)
Other financing activities	637	(1,537)
Net cash flows provided by financing activities	29,862	592,048
Net increase in cash and cash equivalents	159,161	67,714
Cash and cash equivalents - beginning of period	89,816	15,104
		\$
Cash and cash equivalents - end of period	\$ 248,977	82,818

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

NORTHEAST UTILITIES AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (All Companies)

A.

Presentation

Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). The accompanying unaudited condensed consolidated financial statements should be read in conjunction with the entirety of this combined Quarterly Report on Form 10-Q, the first and second quarter 2009 combined Quarterly Reports on Form 10-Q, and the combined Annual Report of Northeast Utilities (NU or the Company), The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), which was filed with the SEC as part of the Northeast Utilities and subsidiaries combined 2008 Annual Report on Form 10-K (NU 2008 Form 10-K). The accompanying unaudited condensed consolidated financial statements contain, in the opinion of management, all adjustments (including normal, recurring adjustments) necessary to present fairly NU's and the above companies' financial position as of September 30, 2009 and December 31, 2008, the results of operations for the three and nine months ended September 30, 2009 and 2008, and cash flows for the nine months ended September 30, 2009 and 2008. The results of operations for the three months ended September 30, 2009 and 2008, and the results of operations and cash flows for the nine months ended September 30, 2009 and 2008, are not necessarily indicative of the results expected for a full year.

The unaudited condensed 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 unaudited condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the unaudited condensed 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 Financial Accounting Standards Board (FASB) 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 unaudited condensed 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 unaudited condensed 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 while certain conditions exist, such as if preferred dividends are in arrears for one year.

The Net income reported in the accompanying unaudited condensed 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.

The included presentation and disclosure requirements effective January 1, 2009 have been applied retrospectively to the unaudited condensed consolidated balance sheet as of December 31, 2008, the unaudited condensed consolidated statements of income for the three and nine months ended September 30, 2008, the unaudited condensed consolidated statement of cash flows for the nine months ended September 30, 2008, and to consolidated comprehensive income for the three and nine months ended September 30, 2008 included in Note 6, "Comprehensive Income," to the unaudited condensed consolidated financial statements. For the nine months ended September 30, 2009 and 2008, there was no change in NU parent's 100 percent ownership of common equity of CL&P.

NU has certain other reclassifications of prior period data included in the accompanying unaudited condensed consolidated balance sheets for PSNH and WMECO and the unaudited condensed consolidated statements of cash flows for all companies presented, which have been made to conform with the current period's presentation.

B.

Accounting Standards Issued But Not Yet Adopted

In June 2009, the FASB issued guidance on the consolidation of variable interest entities (VIEs) that requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a VIE. This analysis identifies the party that must consolidate a VIE, referred to as the primary beneficiary, as the enterprise that has both of the following characteristics: (a) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and (b) the obligation to absorb losses of or receive benefits from the entity that could potentially be significant to the VIE. The guidance eliminates the quantitative approach for determining the primary beneficiary of a VIE, which was based on identifying which party absorbs the majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both. This guidance is effective as of January 1, 2010, for interim and annual reporting periods beginning in 2010.

Earlier application is prohibited. NU, including CL&P, PSNH, and WMECO, does not currently consolidate any VIEs with which the company is associated, and management does not expect to change the accounting for these VIEs as a result of implementing this guidance.

In August 2009, the FASB issued accounting guidance on measuring liabilities at fair value, which is effective in the fourth quarter of 2009 and provides guidance on how to measure the fair value of a liability when a quoted price for the liability is not available. The guidance reaffirms existing guidance requiring that fair values reflect the price that NU would expect to pay to transfer the liabilities in the current market. The guidance is not expected to affect the financial statements of NU, CL&P, PSNH, or WMECO upon adoption.

C.

Accounting Standards Recently Adopted

On January 1, 2009, NU, including CL&P, PSNH and WMECO, adopted fair value measurement guidance for nonrecurring fair value measurements of nonfinancial assets and liabilities, including asset retirement obligations (AROs) and goodwill and other impairment analyses. NU adopted the guidance for fair value measurements of financial assets and liabilities effective January 1, 2008. Implementation of the guidance for nonfinancial assets and liabilities did not affect the accompanying unaudited condensed consolidated financial statements. Application of this guidance to the Yankee Gas Services Company (Yankee Gas) goodwill impairment analysis, which is performed as of October 1st of each year, is not expected to have a material effect on the Company's financial position or results of operations.

In the second quarter of 2009, NU, including WMECO, adopted guidance related to the recognition and presentation of other-than-temporary impairments. This guidance changes the indicators for determining if unrealized losses on debt securities (the excess of amortized cost over fair value) should be recorded in Net income as other-than-temporary impairments. Beginning in the second quarter of 2009, other-than-temporary impairments of debt securities in NU's Trust Under Supplemental Executive Retirement Plan (NU supplemental benefit trust) are

reflected in the Company's unaudited condensed consolidated statement of income if the Company either intends to sell the security or would more likely than not be required to sell the security before recovery to its amortized cost, or if the Company does not expect to recover the amortized cost as a result of a credit loss. For securities that the Company does not intend to sell and it is not more likely than not that it will be required to sell before recovery, only the credit loss component of an impairment is recognized in Net income, and the remainder is recognized in Accumulated other comprehensive income/(loss). NU recorded an after-tax cumulative effect of a change in accounting principle of \$0.7 million as an increase to the April 1, 2009 balance of Retained earnings with an offset to Accumulated other comprehensive income/(loss) relating to the reversal of unrealized losses previously recorded in Net income on debt securities held in the NU supplemental benefit trust, which did not meet the criteria described above. The guidance had no impact on unrealized losses in WMECO's spent nuclear fuel trust as unrealized losses including impairments are recorded in Deferred debits and other assets - other on the accompanying unaudited condensed consolidated balance sheet due to the regulatory accounting treatment of this trust.

In the second quarter of 2009, NU, including CL&P, PSNH and WMECO, adopted guidance which clarifies how to estimate fair value when the volume and level of activity for an asset or liability have significantly decreased and how to identify transactions that are not orderly. This guidance requires additional disclosures related to fair value measurements (refer to Note 1D, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the unaudited condensed consolidated financial statements). Implementation of this guidance did not affect the companies' valuation of assets or liabilities that are measured at fair value.

In the second quarter of 2009, the FASB issued guidance regarding subsequent events, which incorporates into FASB authoritative literature accounting guidance that originated as auditing standards about events or transactions that occur after the balance sheet date but before financial statements are issued. This guidance, which was effective in the second quarter, retains the auditing standard requirements to recognize in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed at the balance sheet date and to disclose but not recognize in the financial statements subsequent events that provide evidence about conditions that arose after the balance sheet date but before the financial statements are issued. NU is required to disclose the date through which it has evaluated subsequent events. In preparing the accompanying unaudited condensed consolidated financial statements, NU has evaluated events subsequent to September 30, 2009 through the issuance of the financial statements on November 6, 2009 and NU has not identified any events for recognition or disclosure.

D.

Fair Value Measurements

The Company measures its derivative instruments that are not designated as normal purchases or normal sales and marketable securities at fair value.

Fair Value Hierarchy: In measuring fair value the Company 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 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. 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 as follows:

Derivative instruments: Many of the Company's derivative positions that are recorded at fair value are classified as Level 3 within the fair value hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs used in the valuations 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 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 nonperformance risk, including credit. The derivative contracts classified as Level 3 include NU Enterprises, Inc. (NU Enterprises) remaining wholesale marketing contract and its related supply contracts, CL&P's contracts for differences (CfDs), CL&P's contracts with certain independent power producers (IPPs), PSNH and Yankee Gas physical options and CL&P and PSNH financial transmission rights (FTRs).

Other derivative contracts recorded at fair value are classified as Level 2 within the fair value hierarchy. An active market for the same or similar contracts exists for these contracts, which include PSNH forward contracts to purchase energy and interest rate swap agreements. For these contracts, valuations are based on quoted prices in the market and include some modeling using market-based assumptions.

For further information on derivative contracts, see Note 2, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

Marketable securities: NU and WMECO hold in trust marketable securities, which include equity securities, mutual funds and cash equivalents, and fixed maturity securities.

Equity securities, mutual funds and cash equivalents are classified as Level 1 in the fair value hierarchy. These investments are traded in active markets and quoted prices for identical investments are available and used in NU's fair value measurements.

Fixed maturity securities classified as Level 2 within the fair value hierarchy include U.S. Treasury securities, corporate bonds, collateralized mortgage obligations, U.S. pass-through bonds, asset-backed securities, commercial mortgage-backed securities, and commercial paper. The fair value of these instruments is estimated 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.

For further information see Note 3, "Fair Value Measurements," and Note 10, "Marketable Securities," to the unaudited condensed consolidated financial statements.

There were no changes to the valuation methodologies for derivative instruments or marketable securities for the three or nine months ended September 30, 2009.

E.

Regulatory Accounting

The accounting policies of the regulated companies, as defined below, conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process.

The transmission and distribution segments of CL&P, PSNH (including its generation business) and WMECO, along with Yankee Gas' distribution segment (collectively, the regulated companies), continue to be rate-regulated on a cost-of-service basis. Management believes it is probable that NU's regulated companies will recover their respective investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets, the majority of deferred benefit costs and regulatory assets offsetting regulated company derivative liabilities, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in Amortization of regulatory assets/(liabilities), net on the accompanying unaudited condensed consolidated statements of income.

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

(Millions of Dollars)	As of September 30, 2009		As of December 31, 2008	
	NU		NU	
Deferred benefit costs	\$	1,091.3	\$	1,140.9
Regulatory assets offsetting derivative liabilities		770.7		844.2
Securitized assets		493.5		677.4
Income taxes, net		353.6		355.4
Unrecovered contractual obligations		154.4		169.1

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CL&P undercollections		58.4		75.2
Storm cost deferral		62.8		19.3
Other regulatory assets		185.9		221.1
Totals	\$	3,170.6	\$	3,502.6

(Millions of Dollars)	As of September 30, 2009			As of December 31, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Deferred benefit costs	\$ 515.4	\$ 133.8	\$ 109.4	\$ 537.7	\$ 142.9	\$ 113.5
Regulatory assets offsetting derivative liabilities	719.4	50.8	-	751.9	92.1	-
Securitized assets	240.1	192.3	61.1	377.8	227.6	72.0
Income taxes, net	301.0	20.3	17.7	306.8	16.1	20.7
Unrecovered contractual obligations	121.5	-	32.9	132.6	-	36.5
CL&P undercollections	58.4	-	-	75.2	-	-
Storm cost deferral	-	52.9	9.9	-	8.2	11.1
WMECO recoverable nuclear costs	-	-	1.8	-	-	5.0
Other regulatory assets	64.2	56.6	15.9	92.1	63.0	9.6
Totals	\$ 2,020.0	\$ 506.7	\$ 248.7	\$ 2,274.1	\$ 549.9	\$ 268.4

Additionally, the regulated companies had \$18 million (\$0.1 million for PSNH, \$9 million for CL&P, and \$8.9 million for WMECO) and \$68.3 million (\$62.7 million for PSNH and \$5.6 million for CL&P) of regulatory costs as of September 30, 2009 and December 31, 2008, respectively, which were included in Deferred debits and other assets - other on the accompanying unaudited condensed 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 recoverable in future cost-of-service regulated rates. As of December 31, 2008, \$62.7 million related to costs incurred at PSNH for the December 2008 storm restorations that met the New Hampshire Public Utilities Commission (NHPUC) specified criteria for deferral to a major storm cost reserve. In July 2009, the NHPUC concluded in a temporary rate order that PSNH could begin recovery of the storm costs. The NHPUC is currently reviewing these costs in connection with the permanent rate case filing. These costs are classified as a regulatory asset as of September 30, 2009.

Included in NU's other regulatory assets are the regulatory assets associated with the accounting for conditional AROs totaling \$45.2 million (\$25.1 million for CL&P, \$14.4 million for PSNH, and \$3 million for WMECO) as of September 30, 2009 and \$42.3 million (\$23.1 million for CL&P, \$13.9 million for PSNH, and \$2.8 million for WMECO) as of December 31, 2008. Management believes that recovery of the conditional ARO regulatory assets is probable.

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

(Millions of Dollars)	As of September 30, 2009		As of December 31, 2008	
	NU		NU	
Cost of removal	\$	215.4	\$	226.0
Regulatory liabilities offsetting derivative assets		118.9		137.8
Regulatory overcollections		64.4		75.4
CL&P AFUDC transmission incentive		49.4		47.6
PSNH ES deferral		24.8		33.0
Pension and PBOP liabilities - Yankee		15.6		17.6
Gas acquisition				
Overrecovered gas costs		14.2		16.9
Other regulatory liabilities		26.6		38.2
Totals	\$	529.3	\$	592.5

(Millions of Dollars)	As of September 30, 2009			As of December 31, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Cost of removal	\$ 85.6	\$ 62.4	\$ 17.0	\$ 91.2	\$ 64.7	\$ 19.2
Regulatory liabilities offsetting derivative assets	117.8	1.1	-	131.3	4.6	-
Regulatory overcollections	54.6	6.2	3.6	69.5	4.6	1.3
CL&P AFUDC transmission incentive	49.4	-	-	47.6	-	-
PSNH ES deferral	-	24.8	-	-	33.0	-
WMECO provision for rate refunds	-	-	1.3	-	-	1.3
WMECO transition charge overcollections	-	-	-	-	-	5.7
WMECO pension/PBOP tracker	-	-	0.1	-	-	2.0
Other regulatory liabilities	18.0	4.9	1.6	23.9	4.5	0.3
Totals	\$ 325.4	\$ 99.4	\$ 23.6	\$ 363.5	\$ 111.4	\$ 29.8

F.**Allowance for Funds Used During Construction**

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 unaudited condensed consolidated statements of income.

(Millions of Dollars, except percentages)	For the Three Months Ended		For the Nine Months Ended	
	September 30,	September 30,	September 30,	September 30,
	2009	2008	2009	2008
	NU	NU	NU	NU
Borrowed funds	\$ 1.2	\$ 4.3	\$ 4.7	\$ 13.5
Equity funds	2.8	8.5	6.2	23.5
Totals	\$ 4.0	\$ 12.8	\$ 10.9	\$ 37.0
Average AFUDC rates	6.4%	8.4%	6.2%	8.3%

(Millions of Dollars, except percentages)	For the Three Months Ended					
	September 30, 2009			September 30, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Borrowed funds	\$ 0.4	\$ 0.8	\$ -	\$ 3.3	\$ 0.6	\$ 0.3
Equity funds	1.9	0.9	-	7.0	0.9	0.5
Totals	\$ 2.3	\$ 1.7	\$ -	\$ 10.3	\$ 1.5	\$ 0.8
Average AFUDC rates	8.2%	6.1%	0.8% *	8.8%	7.9%	8.4%

*

The AFUDC rate applies to WMECO's portion of construction work in progress (CWIP) that is currently recovered in rate base, as further described below.

(Millions of Dollars, except percentages)	For the Nine Months Ended					
	September 30, 2009			September 30, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Borrowed funds	\$ 1.9	\$ 2.4	\$ 0.2	\$ 10.0	\$ 2.2	\$ 0.7
Equity funds	3.5	2.5	-	19.4	3.2	0.9

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Totals	\$	5.4	\$	4.9	\$	0.2	\$	29.4	\$	5.4	\$	1.6
Average AFUDC rates		6.8%		6.7%		2.0%		8.6%		7.6%		7.6%

The regulated companies' average AFUDC rate is based on a Federal Energy Regulatory Commission (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 New England East-West Solutions 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.

G.

Other Income, Net

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

NU (Million of Dollars)	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
Other Income:				
Interest income	\$ 0.4	\$ 10.1	\$ 4.4	\$ 10.1
Investment income	5.5	2.3	9.6	6.1
AFUDC - equity funds	2.8	8.5	6.2	23.5
Energy Independence Act incentives	0.5	0.5	4.9	9.4
C&LM incentives	-	0.1	0.5	-
Other	0.3	0.2	0.7	0.8
Total Other Income	9.5	21.7	26.3	49.9
Other Loss:				
Investment loss	-	(4.0)	-	(7.8)
C&LM costs	-	-	-	(0.3)
Rental expense	-	-	(0.2)	(0.2)
Total Other Loss	-	(4.0)	(0.2)	(8.3)
Total Other Income, Net	\$ 9.5	\$ 17.7	\$ 26.1	\$ 41.6

CL&P (Millions of Dollars)	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
Other Income:				
Interest income	\$ 0.7	\$ 6.4	\$ 2.6	\$ 6.4

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Investment income	3.5	1.7	5.7	5.0
AFUDC - equity funds	1.9	7.0	3.5	19.4
Energy Independence Act incentives	0.6	0.5	4.9	9.4
C&LM incentives	-	-	0.3	-
Other	0.4	0.2	1.0	0.5
Total Other Income	7.1	15.8	18.0	40.7
Other Loss:				
Rental expense	-	-	(0.1)	-
Investment loss	-	(2.7)	-	(5.3)
C&LM costs	-	-	-	(0.6)
Total Other Loss	-	(2.7)	(0.1)	(5.9)
Total Other Income, Net	\$ 7.1	\$ 13.1	\$ 17.9	\$ 34.8

PSNH (Millions of Dollars)	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
Other Income:				
Interest income	\$ 0.4	\$ 1.9	\$ 2.2	\$ 1.9
Investment income	0.8	0.5	1.4	1.4
AFUDC - equity funds	0.9	0.9	2.5	3.2
Other	0.1	-	0.4	0.1
Total Other Income	2.2	3.3	6.5	6.6
Investment loss	-	(0.6)	-	(1.3)
Total Other Income, Net	\$ 2.2	\$ 2.7	\$ 6.5	\$ 5.3

WMECO (Millions of Dollars)	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
Other Income:				
Interest income	\$ (0.6)	\$ 1.1	\$ (0.4)	\$ 1.1
Investment income	0.8	0.2	1.2	0.9
AFUDC - equity funds	-	0.5	-	0.9
Other	-	-	0.2	-
C&LM incentives	-	0.1	0.2	0.3
Total Other Income	0.2	1.9	1.2	3.2
Other Loss:				
Investment loss	-	(0.6)	-	(1.1)
Rental expense	-	-	(0.1)	-
Total other loss	-	(0.6)	(0.1)	(1.1)
Total Other Income, Net	\$ 0.2	\$ 1.3	\$ 1.1	\$ 2.1

Investment income includes equity in earnings of regional nuclear generating and transmission companies of \$0.4 million and \$0.4 million for NU (\$0.1 million in both periods for CL&P and de minimis amounts for PSNH and WMECO) for the three months ended September 30, 2009 and 2008, respectively, and \$1.4 million in both periods for NU (\$0.3 million in both periods for CL&P, \$0.1 million in both periods for WMECO and de minimis amounts for PSNH) for the nine months ended September 30, 2009 and 2008, respectively. Equity in earnings relates to the Company's investments, including CL&P, PSNH and WMECO's investments, in Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company, and Yankee Atomic Electric Company, and NU's investments in two regional transmission companies.

For both the three and nine months ended September 30, 2009, NU and WMECO's interest income included a \$0.7 million tax refund adjustment. For both the three and nine months ended September 30, 2008, interest income for NU, CL&P, PSNH, and WMECO included \$10.1 million, \$6.4 million, \$1.9 million, and \$1.1 million, respectively, of interest income from other federal tax settlements.

H.

Special Deposits and Counterparty Deposits

To the extent NU Enterprises, a wholly owned subsidiary of NU, through its wholly owned subsidiary Select Energy, Inc. (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.

NU, including CL&P, PSNH, and WMECO, records special deposits and counterparty deposits posted under a master netting agreement as an offset to a derivative asset or liability if the related derivatives are recorded in a net position.

As of September 30, 2009, CL&P and Select Energy had \$1 million and \$0.9 million, respectively, of collateral posted under master netting agreements and netted against the fair value of the derivatives. As of December 31, 2008, NU, including CL&P, PSNH and WMECO, had no special deposits and no counterparty collateral posted under master netting agreements netted against the fair value of derivatives.

Special deposits paid by Select Energy to unaffiliated counterparties and brokerage firms not subject to master netting agreements totaled \$29.3 million and \$26.3 million as of September 30, 2009 and December 31, 2008, respectively.

These amounts are recorded as Current assets and are included in Prepayments and other on the accompanying unaudited condensed consolidated balance sheets. There were no counterparty deposits for Select Energy as of September 30, 2009 and December 31, 2008.

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 September 30, 2009 and December 31, 2008, there were no counterparty deposits for these companies.

I.

Income Taxes

Tax Positions: In June 2009, the Internal Revenue Service (IRS) completed its audit of the federal tax years 2005 through 2007, bringing closure to, and effective settlement of, issues concerning the timing of certain deductions through 2007 for NU. For the nine months ended September 2009, the audit closure reduced pre-tax interest expense by \$5.4 million (\$3.1 million for CL&P, \$1.6 million for PSNH, and \$0.5 million for WMECO), and a \$1 million reduction to income tax expense. Management estimates that resolution of this audit decreases NU's unrecognized tax benefits by approximately \$32 million (\$16 million for CL&P, \$12 million for PSNH, and \$3 million for WMECO).

NU is currently working to resolve all open tax years. 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 could result in a \$1 million to \$34 million decrease in unrecognized tax benefits for NU (\$1 million to \$14 million for CL&P and a de minimis impact for PSNH and WMECO).

J.

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. For the three and nine months ended September 30, 2009, NU gross receipts taxes, franchise taxes and other excise taxes of \$33.6 million and \$103.4 million, respectively, (\$31.7 million and \$90.4 million, respectively, for CL&P) were included in Operating revenues and Taxes other than income taxes on the accompanying unaudited condensed consolidated statements of income. For the three and nine months ended September 30, 2008, these amounts totaled \$33.9 million and \$92.4 million, respectively (\$31.4 million and \$78.4 million, respectively, for CL&P). 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 unaudited condensed consolidated statements of income.

2.

DERIVATIVE INSTRUMENTS (NU, NU Enterprises, CL&P, PSNH, Yankee Gas)

Derivative contracts that meet the definition of and are designated as "normal purchases or normal sales" (normal) are recognized in Operating revenues or Operating expenses, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not designated as accounting hedges, or as normal, 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, including CL&P, PSNH and Yankee Gas, 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 designated as hedging instruments."

CL&P, PSNH, WMECO and Yankee Gas 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 standard or last resort 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. CL&P has entered into derivatives, including FTR contracts and bilateral basis swaps, to manage the risk of congestion costs associated with its standard offer and last resort service 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.

The derivative contracts not accounted for as normal are accounted for at fair value. Management believes any costs or benefits from these contracts are recoverable from or refunded to CL&P's customers, therefore any changes in fair value are recorded as Regulatory assets and Regulatory liabilities.

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 default 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. The derivative contracts not accounted for as normal are accounted for at fair value. Management believes any costs or benefits from these contracts are recoverable from or refunded to PSNH's customers, therefore any changes in fair value are recorded as Regulatory assets and Regulatory liabilities.

Yankee Gas mitigates the risks associated with supply availability and volatility of natural gas prices through the use of storage facilities and long-term agreements to purchase gas supply for customers that include nonderivative contracts and contracts that are accounted for as normal. Yankee Gas also manages price risk through the use of options contracts. The derivative contracts not accounted for as normal are accounted for at fair value, and because management believes any costs or benefits from these contracts are recoverable from or refundable to Yankee Gas' customers, any changes in fair value are recorded as Regulatory assets and Regulatory liabilities.

NU Enterprises, through Select Energy, has one remaining fixed price forward sales contract that was part of its wholesale energy marketing business. NU Enterprises mitigates the price risk associated with this contract through the use of forward purchase contracts. NU Enterprises' derivative contracts are accounted for at fair value, and changes in their fair values are recorded in Operating expenses.

NU is also exposed to interest rate risk associated with its long-term debt. From time to time, the Company enters into forward starting interest rate swaps, accounted for as cash flow hedges, to mitigate the risk of changes in interest rates when it expects 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 fixed and floating rate debt. The interest rate swap mitigating the interest rate risk associated with the fixed rate long-term debt 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 unaudited condensed 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 September 30, 2009														
(Millions of Dollars)	Gross Asset		Gross Liability		Net Amount Recorded as Derivative Asset		Gross Asset		Gross Liability		Cash Collateral Posted	Net Amount Recorded as Derivative Liability		
Derivatives not designated as hedging instruments														
<u>NU Enterprises:</u>														
<i>Commodity sales contract and related price and supply risk management:</i>														
Current	\$	-	\$	-	\$	-	\$	2.9	\$	(11.1)	\$	0.9	\$	(7.3)
Long-Term		-		-		-		4.4		(41.6)		-		(37.2)
<u>Regulated Companies:</u>														

*CL&P commodity
and capacity
contracts
required by
regulation:*

Current	16.0	(4.4)	11.6	-	(7.4)	-	(7.4)
Long-Term	252.0	(45.0)	207.0	-	(810.8)	-	(810.8)

*Commodity price
and supply risk
management:*

CL&P:

Current	2.2	-	2.2	-	(2.0)	1.0	(1.0)
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PSNH:

Current ⁽¹⁾	0.6	-	0.6	-	(40.7)	-	(40.7)
Long-Term ⁽¹⁾	0.5	-	0.5	-	(10.2)	-	(10.2)

Yankee Gas:

Current	-	-	-	-	(0.4)	-	(0.4)
Long-Term	-	-	-	-	(0.1)	-	(0.1)

**Derivatives
designated as
hedging
instruments**

*Interest rate risk
management:*

Current ⁽²⁾	4.8	-	4.8	-	-	-	-
Long-Term	10.3	-	10.3	-	-	-	-

(1)

On PSNH's accompanying unaudited condensed consolidated balance sheet, the current portion of the net derivative asset is shown in Prepayments and other and the long-term portion is shown in Deferred debits and other assets - other.

(2)

Amount does not include interest receivable of \$5.1 million as of September 30, 2009 recorded in Prepayments and other on the accompanying unaudited condensed consolidated balance sheet.

For further information on the fair value of derivative contracts, see Note 3, "Fair Value Measurements," to the unaudited condensed consolidated financial statements.

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

Derivatives not designated as hedging instruments

NU Enterprises' energy sales contract and related price risk management: As of September 30, 2009, NU Enterprises had approximately 0.4 million megawatt-hours (MWh) of supply volumes remaining in its wholesale portfolio when expected sales to the New York Municipal Power Agency (an agency that is comprised of municipalities) are compared with contracted supply, both of which extend through 2013.

CL&P energy and capacity contracts required by regulation: CL&P has 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 of The United Illuminating Company (UI) is expected to be approximately 787 megawatts (MW). CL&P has an agreement with UI, which is also accounted for as a derivative, under which they 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 New England Independent System Operator capacity markets for periods of up to 15 years beginning in 2009.

CL&P, PSNH and Yankee Gas energy and natural gas price risk management: As of September 30, 2009, CL&P had 0.5 million MWh and 0.4 million MWh remaining under FTRs and bilateral basis swaps, respectively, that expire by December 31, 2009 and require monthly payments or receipts.

PSNH has electricity procurement contracts with delivery dates through 2011 to purchase an aggregate amount of 1.7 million MWh of power 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 0.7 million MWh of electricity through December 2010. In addition, PSNH has entered into FTRs to manage the risk of congestion costs associated with its electricity delivery service. As of September 30, 2009, there were 0.4 million MWh remaining under FTRs that expire in 2009 and require 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.

As of September 30, 2009, Yankee Gas had two peaking supply option contracts to purchase up to 17 thousand MMBtu of natural gas on up to 20 days per season to manage natural gas supply price risk related to winter load obligations. One contract for 3 thousand MMBtu expires on October 31, 2009 and the other contract for 14 thousand MMBtu expires on April 1, 2012. Demand fees on these contracts are settled annually or seasonally and are included in Yankee Gas' Purchased Gas Adjustment clause for recovery.

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The following table presents the realized and unrealized gains/(losses) associated with derivative contracts not designated as hedging instruments for the three and nine months ended September 30, 2009:

Derivatives Not Designated as Hedging Instruments	Location of Gain or Loss Recognized on Derivative	Amount of Gain/(Loss) Recognized on Derivative Instrument	
		Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
		(Millions of Dollars)	
<u>NU Enterprises:</u>			
Energy sales contract and energy price risk management	Fuel, purchased and net interchange power	\$(1.5)	\$6.4
<u>Regulated Companies:</u>			
CL&P energy and capacity contracts required by regulation	Regulatory assets/liabilities	(31.8)	18.3
Commodity price and supply risk management:			
CL&P	Regulatory assets/liabilities	(0.9)	(7.9)
PSNH	Regulatory assets/liabilities	(7.2)	(58.0)
Yankee Gas	Regulatory assets/liabilities	(0.4)	(2.5)

For the regulated companies, monthly settlement amounts are recorded as receivables or payables and as Operating revenues or Fuel, purchased and net interchange power. Regulatory assets/liabilities are established with no impact to Net income.

Derivatives designated as hedging instruments

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 qualified and was designated as a fair value hedge and requires semi-annual payments/receipts. The changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in interest expense. There was no

ineffectiveness recorded for the three and nine months ended September 30, 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.

For the three and nine months ended September 30, 2009, 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:

(Millions of Dollars) Income Statement Classification	Swap		Hedged Debt	
	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Changes in fair value	\$ 4.0	\$ 0.8	\$ (4.0)	\$ (0.8)
Interest recorded in Net income	-	-	2.7	6.5

There were no cash flow hedges outstanding as of or during the three and nine month periods ended September 30, 2009 and no ineffectiveness was recorded during those 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.

For the three and nine months ended September 30, 2009, pre-tax gains/(losses) amortized from Accumulated other comprehensive income/(loss) into Interest expense were as follows:

(Millions of Dollars)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
CL&P	\$ (0.2)	\$ (0.6)
PSNH	-	(0.1)
WMECO	-	0.1

Other		0.1		0.3
NU	\$	(0.1)	\$	(0.3)

For further information, see Note 6, "Comprehensive Income," to the unaudited condensed consolidated financial statements.

Credit Risk

Certain derivative contracts that are accounted for at fair value, including PSNH's electricity procurement contracts, CL&P's bilateral agreements 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 letters of credit (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 September 30, 2009:

(Millions of Dollars)	Fair Value Subject to Credit Risk Contingent Features	Cash Collateral Posted	Standby LOCs Posted
CL&P	\$ (0.3)	\$ 1.0	\$ -
PSNH	(50.8)	-	56.0
NU Enterprises	(17.0)	0.9	-
NU	\$ (68.1)	\$ 1.9	\$ 56.0

Additional collateral is required to be posted by NU Enterprises, CL&P or PSNH, respectively, if NU parent's, CL&P's or PSNH's respective unsecured debt credit ratings are downgraded below investment grade. As of September 30, 2009, no additional cash collateral would be required to be posted if credit ratings were downgraded below investment grade. However, if PSNH's or NU parent's senior unsecured debt were downgraded to below investment grade, additional standby LOCs in the amount of \$14.8 million and \$17.1 million would be 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 unaudited condensed consolidated financial statements.

3.

FAIR VALUE MEASUREMENTS (All Companies)

The following tables present the amounts of assets and liabilities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

As of September 30, 2009								NUSCO and NU Parent
(Millions of Dollars)	Total NU	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas		
Derivative Assets:								
Level 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Level 2	15.1	-	-	-	-	-	15.1	
Level 3	221.9	220.8	1.1	-	-	-	-	
Total	\$ 237.0	\$ 220.8	\$ 1.1	\$ -	\$ -	\$ -	\$ 15.1	
Derivative Liabilities:								
Level 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Level 2	(50.8)	-	(50.8)	-	-	-	-	
Level 3	(866.2)	(820.2)	(0.1)	-	(45.4)	(0.5)	-	
Cash collateral posted	1.9	1.0	-	-	0.9	-	-	
Total	\$ (915.1)	\$ (819.2)	\$ (50.9)	\$ -	\$ (44.5)	\$ (0.5)	\$ -	
Marketable Securities:								
Level 1:								
Mutual funds	\$ 34.7	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 34.7	
Money market and other	5.7	-	-	4.8	-	-	0.9	
Total Level 1	40.4	-	-	4.8	-	-	35.6	
Level 2:								
U.S. government issued debt securities (agency and treasury)	31.5	-	-	17.0	-	-	14.5	
	25.8	-	-	18.1	-	-	7.7	

Corporate debt
securities

Asset backed securities	5.2	-	-	1.0	-	-	4.2
Municipal bonds	10.8	-	-	10.6	-	-	0.2
Other	5.5	-	-	5.1	-	-	0.4
Total Level 2	78.8	-	-	51.8	-	-	27.0
Total	\$ 119.2	\$ -	\$ -	\$ 56.6	\$ -	\$ -	\$ 62.6

As of December 31, 2008

(Millions of Dollars)	Total NU	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	NUSCO and NU Parent
Derivative Assets:							
Level 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Level 2	20.8	-	-	-	-	-	20.8
Level 3	252.4	245.8	4.7	-	-	1.9	-
Total	\$ 273.2	\$ 245.8	\$ 4.7	\$ -	\$ -	\$ 1.9	\$ 20.8
Derivative Liabilities:							
Level 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Level 2	(91.7)	-	(91.7)	-	-	-	-
Level 3	(921.6)	(856.9)	(0.6)	-	(63.9)	(0.2)	-
Total	\$ (1,013.3)	\$ (856.9)	\$ (92.3)	\$ -	\$ (63.9)	\$ (0.2)	\$ -
Marketable Securities:							
Level 1	\$ 42.1	\$ -	\$ -	\$ 10.3	\$ -	\$ -	\$ 31.8
Level 2	67.1	-	-	45.4	-	-	21.7
Level 3	-	-	-	-	-	-	-
Total	\$ 109.2	\$ -	\$ -	\$ 55.7	\$ -	\$ -	\$ 53.5

Not included in the tables above are \$234.6 million and \$81.6 million of cash equivalents held by NU parent as of September 30, 2009 and December 31, 2008, respectively, which are included in cash and cash equivalents on the accompanying unaudited condensed consolidated balance sheets and are classified as Level 1 in the fair value hierarchy.

The following tables present changes for the three and nine months ended September 30, 2009 and 2008 in the Level 3 category of assets and liabilities measured at fair value on a recurring basis. This category includes derivative assets

and liabilities, which 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 three and nine months ended September 30, 2009 and 2008.

For the Three Months Ended September 30, 2009

(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
<u>Derivatives, Net:</u>					
Fair value as of June 30, 2009	\$ (614.0)	\$ (570.5)	\$ 1.3	\$ (44.7)	\$ (0.1)
Net realized/unrealized losses included in:					
Net income ⁽¹⁾	(1.5)	-	-	(1.5)	-
Regulatory assets/liabilities	(33.4)	(32.7)	(0.3)	-	(0.4)
Purchases, issuances and settlements	4.6	3.8	-	0.8	-
Fair value as of September 30, 2009	\$ (644.3)	\$ (599.4)	\$ 1.0	\$ (45.4)	\$ (0.5)
Quarterly change in unrealized losses included in Net income relating to items held as of September 30, 2009	\$ (1.4)	\$ -	\$ -	\$ (1.4)	\$ -

For the Three Months Ended September 30, 2008

(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
<u>Derivatives, Net:</u>					
Fair value as of June 30, 2008	\$ (277.0)	\$ (244.9)	\$ 40.9	\$ (74.6)	\$ 1.6
Net realized/unrealized gains/(losses) included in:					
Net income ⁽¹⁾	5.3	-	-	5.3	-
Regulatory assets/liabilities	(195.8)	(164.1)	(30.4)	-	(1.3)
Purchases, issuances and settlements	(24.1)	(24.8)	-	0.7	-
Fair value as of September 30, 2008	\$ (491.6)	\$ (433.8)	\$ 10.5	\$ (68.6)	\$ 0.3
Quarterly change in unrealized gains included in Net income relating to items held as of September 30, 2008	\$ 6.0	\$ -	\$ -	\$ 6.0	\$ -

For the Nine Months Ended September 30, 2009

(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
<u>Derivatives, Net:</u>					
Fair value as of January 1, 2009	\$ (669.2)	\$ (611.1)	\$ 4.1	\$ (63.9)	\$ 1.7
Net realized/unrealized gains/(losses) included in:					
Net income ⁽¹⁾	6.4	-	-	6.4	-
Regulatory assets/liabilities	4.9	10.4	(3.0)	-	(2.5)
Purchases, issuances and settlements	13.6	1.3	(0.1)	12.1	0.3
Fair value as of September 30, 2009	\$ (644.3)	\$ (599.4)	\$ 1.0	\$ (45.4)	\$ (0.5)
Period change in unrealized gains included in Net income relating to items held as of September 30, 2009	6.1	-	-	6.1	-

For the Nine Months Ended September 30, 2008

(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
<u>Derivatives, Net:</u>					
Fair value as of January 1, 2008 ⁽²⁾	\$ (511.1)	\$ (426.9)	\$ 15.7	\$ (100.1)	\$ 0.2
Net realized/unrealized gains/(losses) included in:					
Net income ⁽¹⁾	10.2	-	-	10.2	-
Regulatory assets/liabilities	49.7	54.8	(5.2)	-	0.1
Purchases, issuances and settlements	(40.4)	(61.7)	-	21.3	-
Fair value as of September 30, 2008	\$ (491.6)	\$ (433.8)	\$ 10.5	\$ (68.6)	\$ 0.3
Period change in unrealized gains included in Net income relating to items held as of September 30, 2008	4.5	-	-	4.5	-

(1)

Realized and unrealized gains and losses on derivatives included in Net income relate to the remaining Select Energy wholesale marketing contracts and are reported in Fuel, purchased and net interchange power on the accompanying unaudited condensed consolidated statements of income.

(2)

Amounts as of January 1, 2008 reflect fair values after initial adoption of accounting guidance for fair value measurements. As a result of implementation, the Company recorded an increase to derivative liabilities and a pre-tax charge of \$6.1 million as of January 1, 2008 related to NU Enterprises' remaining derivative contracts. The Company also recorded changes in fair value of CL&P's CfD and IPP contracts, resulting in increases to CL&P's Derivative liabilities of approximately \$590 million, with an offset to Regulatory assets and a decrease to CL&P's Derivative assets of approximately \$30 million with an offset to Regulatory liabilities.

4.

PENSION BENEFITS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (All Companies)

Northeast Utilities Service Company (NUSCO), a subsidiary of NU, sponsors a single uniform noncontributory defined benefit retirement plan (Pension Plan), which is subject to the provisions of the Employee Retirement Income Security Act (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). 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 post-retirement benefits other than pension plan (PBOP Plan). In addition, NU maintains a Supplemental Executive Retirement Plan (SERP), which provides benefits to eligible participants who are officers of NU. This plan primarily provides benefits that would have been provided to these employees under the Pension Plan if certain Internal Revenue Code limitations were not imposed.

The components of net periodic expense/(income) for the Pension Plan, PBOP Plan and SERP for the three and nine months ended September 30, 2009 and 2008 are as follows:

NU (Millions of Dollars)	For the Three Months Ended September 30,					
	Pension Benefits		PBOP Benefits		SERP Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	\$ 11.3	\$ 11.1	\$ 1.8	\$ 1.8	\$ 0.2	\$ 0.2
Interest cost	38.3	35.9	7.3	7.0	0.6	0.5
Expected return on plan assets	(47.3)	(50.0)	(5.3)	(5.3)	-	-
Net transition obligation cost	0.1	-	2.8	2.9	-	-
Prior service cost/(credit)	2.4	2.5	-	(0.1)	-	-
Actuarial loss	5.1	1.1	2.6	2.7	0.1	0.1
Total - net periodic expense	\$ 9.9	\$ 0.6	\$ 9.2	\$ 9.0	\$ 0.9	\$ 0.8
	\$ (1.5)	\$ (5.3)	\$ 3.8	\$ 3.9	\$ -	\$ 0.1

**CL&P - net periodic
(income)/expense**

PSNH - net periodic expense	\$	5.8	\$	4.5	\$	1.7	\$	1.8	\$	0.1	\$	0.1
WMECO - net periodic (income)/expense		(0.7)		(1.5)		0.6		0.7		*		*
	\$		\$		\$		\$					

For the Nine Months Ended September 30,

NU (Millions of Dollars)	Pension Benefits		PBOP Benefits		SERP Benefits	
	2009	2008	2009	2008	2009	2008
Service cost	\$ 33.8	\$ 32.8	\$ 5.4	\$ 5.3	\$ 0.6	\$ 0.5
Interest cost	115.1	108.1	21.8	21.2	1.7	1.5
Expected return on plan assets	(142.0)	(150.2)	(15.7)	(15.8)	-	-
Net transition obligation cost	0.2	0.2	8.5	8.7	-	-
Prior service cost/(credit)	7.3	7.4	-	(0.2)	0.1	0.1
Actuarial loss	15.4	3.6	7.9	7.9	0.3	0.2
Total - net periodic expense	\$ 29.8	\$ 1.9	\$ 27.9	\$ 27.1	\$ 2.7	\$ 2.3
CL&P - net periodic (income)/expense	(4.3)	(16.0)	11.6	11.8	0.2	0.2
	\$	\$	\$	\$	\$	\$
PSNH - net periodic expense	\$ 17.4	\$ 13.6	\$ 5.2	\$ 5.3	\$ 0.2	\$ 0.2
WMECO - net periodic (income)/expense	(2.2)	(4.6)	2.0	2.1	*	*
	\$	\$	\$	\$		

*A de minimis amount of SERP expense was recorded for WMECO.

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 Three Months Ended September 30,						
(Millions of Dollars)	CL&P		PSNH		WMECO	
	2009	2008	2009	2008	2009	2008
Pension Benefits	\$ 3.6	\$ 2.0	\$ 0.7	\$ 0.4	\$ 0.6	\$ 0.3
PBOP Benefits	1.8	1.7	0.4	0.4	0.3	0.3
SERP Benefits	0.5	0.4	0.1	0.1	0.1	0.1

For the Nine Months Ended September 30,						
(Millions of Dollars)	CL&P		PSNH		WMECO	
	2009	2008	2009	2008	2009	2008
Pension Benefits	\$ 11.0	\$ 6.0	\$ 2.4	\$ 1.2	\$ 1.8	\$ 1.0
PBOP Benefits	5.5	5.1	1.3	1.1	0.9	0.8
SERP Benefits	1.4	1.2	0.3	0.3	0.2	0.2

A portion of the pension amounts is capitalized related to current employees who are working on capital projects. Amounts capitalized for NU, CL&P, PSNH and WMECO were as follows:

(Millions of Dollars)	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NU	\$ 1.5	\$ (1.4)	\$ 4.6	\$ (4.1)
CL&P	(0.1)	(2.1)	(0.2)	(6.5)
PSNH	1.4	1.2	4.3	3.5
WMECO	(0.2)	(0.6)	(0.5)	(1.7)

The amounts for the three and nine months ended September 30, 2009 and 2008 for CL&P and WMECO, and the amounts for the three and nine months ended September 30, 2008 for NU, offset capital costs, as pension income was recorded related to these capital projects.

COMMITMENTS AND CONTINGENCIES**A.****Long-Term Contractual Arrangements (NU, CL&P)**

Estimated Future Annual CL&P Costs: The estimated future annual costs of CL&P's renewable energy contract arrangements, updated as of September 30, 2009, are as follows:

(Millions of Dollars)	2009	2010	2011	2012	2013	Thereafter	Total
Renewable energy contracts	\$ -	\$ 7.3	\$ 67.9	\$ 152.2	\$ 153.1	\$ 2,245.9	\$ 2,626.4

Renewable Energy Contracts: In May 2009, pursuant to Connecticut's "Act Concerning Energy Independence," the DPUC approved five renewable energy plant projects with total capacity of 27.3 MW. Contracts for the purchase of energy, capacity and renewable energy certificates from these projects have been signed by CL&P and were approved by the DPUC on August 4, 2009. Purchases under the contracts are scheduled to begin from September 2010 through July 2011 and to extend for 15 to 20 years. As directed by the DPUC, CL&P and UI have signed a sharing agreement under which they will share the costs and benefits of these contracts with 80 percent to CL&P and 20 percent to UI. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

B.**Environmental Matters (HWP)**

Holyoke Water Power Company (HWP) is a subsidiary of NU that remains in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant (MGP) site, which it sold to Holyoke Gas and Electric (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 first established a reserve for this site in 1994. In the second quarter of 2009, a pre-tax charge of \$1.1 million was recorded to reflect the estimated cost of additional tar delineation and site characterization studies that are considered to be probable and estimable. The cumulative expense recorded to this reserve through September 30, 2009 was approximately \$17 million, of which \$15.2 million had been spent, leaving approximately \$1.8 million in the reserve as of September 30, 2009.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, which share responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and

providing detailed comments on HWP's 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed and implemented site characterization studies to further delineate tar deposits in conformity with MA DEP's guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, management believes that the \$1.8 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately \$1.8 million to \$2.5 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur throughout the remainder of 2009.

There are many outcomes that could affect management's estimates and require an increase to the reserve, or range of costs, and a reserve increase would be reflected as a charge to pre-tax Net income. However, management cannot reasonably estimate the range of additional investigation and remediation costs because it will depend on, among other things, the level and extent of the remaining tar that may be required to be remediated, the extent of HWP's responsibility and the related scope and timing, all of which are difficult to estimate because of a number of uncertainties at this time. Further developments may require a material increase to this reserve.

HWP's share of the remediation costs related to this site is not recoverable from customers.

C.

Guarantees and Indemnifications (All Companies)

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 Select Energy Services, Inc. (SESI). As of September 30, 2009, the aggregate fair value amount recorded for these guarantees and indemnifications totaled \$0.3 million and is included in Current liabilities - Other on the accompanying unaudited condensed consolidated balance sheets.

In addition, NU parent 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. As of September 30, 2009, 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.

The following table summarizes the NU, including CL&P, PSNH, and WMECO, maximum exposure as of September 30, 2009, in accordance with guidance on guarantor's accounting and disclosure requirements for guarantees, including indirect guarantees of indebtedness of others, and expiration dates:

Company	Description	Maximum Exposure (in millions)	Expiration Date(s)
On behalf of external parties:			
Ameresco Select, Inc.	General indemnifications in connection with the sale of SESI including completeness and accuracy of information provided, compliance with laws, and various claims	Not (1) Specified	None
	Specific indemnifications in connection with the sale of SESI for estimated costs to complete or modify specific projects (2)	Not (1) Specified	Through project completion
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts (3)	\$1.0	2017-2018
	Surety bonds covering certain projects	\$0.4	Through project completion
On behalf of subsidiaries:			
CL&P	Surety bonds	\$2.6	December 2009 - September 2010 (4)
PSNH	Surety bonds	\$4.0	January 2010 - November 2010 (4)
	Letters of credit	\$70.0	January 2010 - July 2010
WMECO	Surety bonds	\$3.7	

May-June
2010 (4)

HWP	Surety bonds	\$1.0	May 2010 (4)
NAESCO (North Atlantic Energy Service Corporation)	Surety bonds	\$1.6	May 2010 (4)
Rocky River Realty Company	Lease payments for real estate	\$11.4	2024
NUSCO	Lease payments for fleet of vehicles	\$6.8	October 2009-2014
	Surety bonds	\$0.4	May 2010 (4)
	Lease payments for real estate	\$2.2	2019
E.S. Boulos Company (Boulos)	Surety bonds covering ongoing projects	\$27.1	Through project completion
Northeast Generation Services Company (NGS)	Performance guarantee and insurance bonds	\$20.4 (5)	2020 (5)
Select Energy	Performance guarantees for wholesale contracts	\$19.1 (6)	2013
	Letters of credit	\$2.0	January 2010
Other - CYAPC	Surety bonds	\$0.3	April 2010 (4)

(1)

No maximum exposure is specified in the related sale agreements.

(2)

The fair value for amounts recorded for these indemnifications was \$0.2 million as of September 30, 2009.

(3)

The fair value for amounts recorded for these indemnifications was \$0.1 million as of September 30, 2009.

(4)

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

(5)

Included in the maximum exposure is \$19.2 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 September 30, 2009 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. The remaining \$1.2 million of maximum exposure relates to insurance bonds with no expiration date that are billed annually on their anniversary date.

(6)

Maximum exposure is as of September 30, 2009; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

CL&P, PSNH and WMECO have no guarantees of 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 NU's unsecured debt credit ratings are downgraded below investment grade.

6.

COMPREHENSIVE INCOME (NU, CL&P, PSNH, WMECO)

Total comprehensive income, which includes all comprehensive income/(loss) items, net of tax and by category, for the three and nine months ended September 30, 2009 and 2008 is as follows:

(Millions of Dollars)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009 NU	2008 NU	2009 NU	2008 NU
Net income	\$ 66.2	\$ 74.1	\$ 249.5	\$ 193.1
Comprehensive income/(loss) items:				
Qualified cash flow hedging instruments	0.1	(1.1)	0.1	(7.0)
Change in unrealized gains/(losses) on other securities ⁽¹⁾	0.3	(0.9)	(0.7)	(1.6)
Pension, SERP and PBOP benefits	0.8	0.1	0.1	2.1
Net change in comprehensive income/(loss) items	1.2	(1.9)	(0.5)	(6.5)
Total comprehensive income	67.4	72.2	249.0	186.6
Comprehensive income attributable to noncontrolling interests	(1.4)	(1.4)	(4.2)	(4.2)
Comprehensive income attributable to controlling interests	\$ 66.0	\$ 70.8	\$ 244.8	\$ 182.4

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Net income	\$ 46.5	\$ 16.2	\$ 8.5	\$ 55.5	\$ 14.3	\$ 5.2
Comprehensive income/(loss) items:						
Qualified cash flow hedging instruments	0.1	-	-	0.1	-	-
Change in unrealized gains/(losses) on other securities ⁽¹⁾	-	-	-	-	-	(0.3)
Net change in comprehensive income/(loss) items	0.1	-	-	0.1	-	(0.3)
Total comprehensive income	\$ 46.6	\$ 16.2	\$ 8.5	\$ 55.6	\$ 14.3	\$ 4.9

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Net income	\$ 158.1	\$ 50.3	\$ 20.5	\$ 147.9	\$ 44.7	\$ 14.8
Comprehensive income/(loss) items:						
Qualified cash flow hedging instruments	0.3	0.1	(0.1)	(3.5)	(1.4)	(0.1)
Change in unrealized gains/(losses) on other securities ⁽¹⁾	-	(0.1)	(0.1)	-	(0.1)	(0.3)
Net change in comprehensive income/(loss) items	0.3	-	(0.2)	(3.5)	(1.5)	(0.4)
Total comprehensive income	\$ 158.4	\$ 50.3	\$ 20.3	\$ 144.4	\$ 43.2	\$ 14.4

(1)

Represents changes in unrealized gains/(losses) on securities held in the NU supplemental benefit trust. For further information, see Note 10, "Marketable Securities," to the unaudited condensed consolidated financial statements.

Fair value adjustments included in Accumulated other comprehensive loss for qualified cash flow hedging instruments are as follows:

NU (Millions of Dollars, Net of Tax)	For the Nine Months Ended September 30, 2009	For the Twelve Months Ended December 31, 2008
Balance at beginning of period	\$ (4.6)	\$ 2.3
Hedged transactions impacting Net income	0.1	0.4
Change in fair value of interest rate swap agreements	-	(7.0)
Cash flow transactions entered into for period	-	(0.3)
Net change associated with hedging transactions	0.1	(6.9)
Total fair value adjustments included in Accumulated other comprehensive loss	\$ (4.5)	\$ (4.6)

(Millions of Dollars, Net of Tax)	Nine Months Ended September 30, 2009			Twelve Months Ended December 31, 2008		
	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Balance at beginning of period	(3.6)	\$ (0.8)	\$ 0.1	(0.3)	\$ 0.6	\$ 0.2
Hedged transactions impacting Net income	0.3	0.1	(0.1)	0.4	0.2	(0.1)
Change in fair value of interest rate swap agreements	-	-	-	(3.7)	(1.4)	-
Cash flow transactions entered into for period	-	-	-	-	(0.2)	-
Net change associated with hedging transactions	0.3	0.1	(0.1)	(3.3)	(1.4)	(0.1)
Total fair value adjustments included in Accumulated other comprehensive (loss)/income	(3.3)	\$ (0.7)	\$ -	(3.6)	\$ (0.8)	\$ 0.1

Hedged transactions impacting Net income in the tables above represent amounts that were reclassified from Accumulated other comprehensive (loss)/income into Net income in connection with the consummation of interest rate swap agreements and the amortization of existing interest rate hedges.

There were no forward starting interest rate swaps entered into for the three and nine months ended September 30, 2009. For NU, it is estimated that a charge of \$0.2 million will be reclassified from Accumulated other

comprehensive loss as a decrease to Net income over the next 12 months as a result of amortization of interest rate swap agreements that 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 September 30, 2009, it is estimated that a pre-tax amount of \$0.7 million included in the Accumulated other comprehensive loss balance will be reclassified as a decrease to Net income over the next 12 months related to Pension Plan, SERP and PBOP Plan benefits adjustments for NU.

7.

EARNINGS PER SHARE (NU)

Earnings per share (EPS) is computed based upon the monthly weighted average number of common shares outstanding, excluding unallocated Employee Stock Ownership Plan (ESOP) shares, during each period. 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. For the nine month period ended September 30, 2009, there were 18,012 share awards excluded from the computation as these awards were antidilutive. There were no antidilutive share awards outstanding for the three month period ended September 30, 2009 and for the three and nine month periods ended September 30, 2008. The weighted average common shares outstanding as of September 30, 2009 includes the impact of the issuance of approximately 19 million common shares on March 20, 2009.

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

(Millions of Dollars, Except for Share Information)	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income attributable to controlling interests	\$ 64.8	\$ 72.7	\$ 245.3	\$ 188.9
Basic common shares outstanding (average)	175,358,776	155,607,201	170,958,396	155,456,606
Dilutive effect	636,730	490,440	574,517	448,265
Fully diluted common shares outstanding (average)	175,995,506	156,097,641	171,532,913	155,904,871
Basic EPS	\$ 0.37	\$ 0.47	\$ 1.43	\$ 1.22
Fully Diluted EPS	\$ 0.37	\$ 0.47	\$ 1.43	\$ 1.21

Restricted share units (RSUs) and performance units are included in basic common shares outstanding when the units have vested and common shares are issued. The dilutive effect of outstanding RSUs and performance units 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 units using the average market price during the period 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 period using the average market price and the grant price).

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

8.

LONG-TERM DEBT (CL&P, Yankee Gas)

On February 13, 2009, CL&P issued \$250 million of first mortgage bonds with a coupon rate of 5.5 percent and a maturity date of February 1, 2019. The proceeds from this issuance were used to repay short-term debt and to fund CL&P's ongoing capital investment programs. The indenture under which the bonds were issued requires CL&P to comply with certain covenants as are customarily included in such indenture. CL&P was in compliance with these covenants as of September 30, 2009.

On April 2, 2009, CL&P completed the remarketing and reissuance of \$62 million of pollution control revenue bonds it had elected to acquire in October 2008. The PCRBS, which mature on May 1, 2031, carry a coupon of 5.25 percent during the current fixed-rate period and are subject to a mandatory tender for purchase on April 1, 2010, at which time CL&P expects to remarket the bonds.

On April 1, 2009, using funds borrowed from the NU Money Pool, Yankee Gas retired \$50 million of first mortgage bonds carrying a coupon of 6.2 percent that were issued in January 1999.

9.

FAIR VALUE OF FINANCIAL INSTRUMENTS (All Companies)

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 rate reduction bonds 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 September 30, 2009						
NU						
(Millions of Dollars)	Carrying Amount	Fair Value				
Preferred stock not subject to mandatory redemption	\$ 116.2	\$ 86.2				
Long-term debt -						
First mortgage bonds	2,507.7	2,663.7				
Other long-term debt	1,893.6	1,939.9				
Rate reduction bonds	503.3	547.2				

As of September 30, 2009						
(Millions of Dollars)	CL&P		PSNH		WMECO	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	116.2	86.2	-	-	-	-
	\$	\$	\$	\$	\$	\$
Long-term debt -						
First mortgage bonds	1,919.8	2,045.1	280.0	295.0	-	-
Other long-term debt	667.4	675.0	407.3	410.0	305.9	307.0

Rate reduction bonds	240.3	261.9	200.6	217.9	62.3	67.4
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Consolidated other long-term debt includes \$300.6 million of fees and interest due for spent nuclear fuel disposal costs as of September 30, 2009. CL&P and WMECO's portions of this obligation are \$243.5 million and \$57.1 million, respectively.

Derivative Instruments: NU, including CL&P, PSNH, and WMECO, holds various derivative instruments that are carried at fair value. For further information, see Note 2, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

Other Financial Instruments: Investments in marketable securities are carried at fair value on the accompanying unaudited condensed consolidated balance sheets. For further information, see Note 3, "Fair Value Measurements," and Note 10, "Marketable Securities," to the unaudited condensed consolidated financial statements.

NU parent holds a long-term government receivable related to SESI. The carrying value of the receivable was \$8.8 million as of September 30, 2009 and is included in Deferred debits and other assets - Other on the accompanying unaudited condensed consolidated balance sheet. The fair value of this receivable was \$10.8 million as of September 30, 2009 and was determined based on discounted cash flows using a seven-year Treasury rate to match the weighted average life of the anticipated cash flow stream.

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.

10.

MARKETABLE SECURITIES (NU, WMECO)

The Company elected to record exchange traded 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 \$34.7 million as of September 30, 2009. Gains on these securities of \$4.7 million and \$5.2 million for the three and nine months ended September 30, 2009, respectively, were recorded in Other income, net on the accompanying unaudited condensed consolidated statements of income. Dividend income is recorded when dividends are declared and are recorded in Other income, net on the accompanying unaudited condensed 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 supplemental benefit trust and WMECO's spent nuclear fuel trust. These securities are recorded at fair value and included in current and long-term marketable securities on the accompanying unaudited condensed consolidated balance sheets.

		As of September 30, 2009			
		Pre-Tax Gross Unrealized Gains ⁽¹⁾		Pre-Tax Gross Unrealized Losses ⁽¹⁾	
(Millions of Dollars)	Amortized Cost				Fair Value
NU supplemental benefit trust					
U.S. government issued debt securities	14.1	0.4	-		14.5
(Agency and Treasury)	\$	\$	\$	\$	
Corporate debt securities	7.3	0.5	(0.1)		7.7
Asset backed debt securities	4.2	0.1	(0.1)		4.2
Municipal bonds	0.2	-	-		0.2
Other	1.3	-	-		1.3
Total NU supplemental benefit trust	27.1	1.0	(0.2)		27.9
	\$	\$	\$	\$	
WMECO spent nuclear fuel trust					
U.S. government issued debt securities					
(Agency and Treasury)	\$	17.0	\$ -	\$ -	\$ 17.0
Corporate debt securities		18.2	0.1	(0.2)	18.1
Asset backed debt securities		1.2	-	(0.2)	1.0
Municipal bonds		10.6	-	-	10.6
Other		9.9	-	-	9.9
Total WMECO spent nuclear fuel trust	\$	56.9	\$ 0.1	\$ (0.4)	\$ 56.6
Total NU	\$	84.0	\$ 1.1	\$ (0.6)	\$ 84.5

(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 loss and Deferred debits and other assets - other, respectively.

For information related to the change in unrealized gains and losses for the NU supplemental benefit trust included in Accumulated other comprehensive loss, see Note 6, "Comprehensive Income," to the unaudited condensed consolidated financial statements.

Unrealized Losses and Other-than-Temporary Impairment: Gross unrealized losses and fair values of debt securities that have been in a continuous unrealized loss position for less than 12 months and 12 months or greater are as follows:

	As of September 30, 2009					
	Less than 12 Months		12 Months or Greater		Total	
(Millions of Dollars)	Fair Value	Pre-Tax Gross Unrealized Losses	Fair Value	Pre-Tax Gross Unrealized Losses	Fair Value	Pre-Tax Gross Unrealized Losses
NU supplemental benefit trust						
Corporate debt securities	\$ -	\$ -	\$ 0.4	\$ (0.1)	\$ 0.4	\$ (0.1)
Asset backed debt securities	-	-	1.4	(0.1)	1.4	(0.1)
Total supplemental benefit trust	\$ -	\$ -	\$ 1.8	\$ (0.2)	\$ 1.8	\$ (0.2)
WMECO spent nuclear fuel trust						
Corporate debt securities	\$ -	\$ -	\$ 0.2	\$ (0.2)	\$ 0.2	\$ (0.2)
Asset backed debt securities	-	-	0.5	(0.2)	0.5	(0.2)
Total WMECO spent nuclear fuel trust	\$ -	\$ -	\$ 0.7	\$ (0.4)	\$ 0.7	\$ (0.4)
Total NU	\$ -	\$ -	\$ 2.5	\$ (0.6)	\$ 2.5	\$ (0.6)

As of September 30, 2009, there were no debt securities that the Company intends to sell or that management believes the Company will more likely than not be required to sell before recovery of amortized cost. Credit losses for the NU supplemental benefit trust were de minimus for the three and nine months ended September 30, 2009. There were no credit losses for the three months ended September 30, 2009 for the WMECO spent nuclear fuel trust. There were \$0.7 million of credit losses for the nine months ended September 30, 2009 recorded in Deferred debits and other assets - Other for the 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 of the Company's corporate and asset-backed securities are rated above investment grade.

Contractual Maturities: As of September 30, 2009, the contractual maturities of available-for-sale debt securities are as follows:

(Millions of Dollars)	NU			WMECO		
	Amortized Cost		Estimated Fair Value	Amortized Cost		Estimated Fair Value
Less than one year	\$ 29.3		\$ 29.2	\$ 28.0		\$ 28.0
One to five years	24.6		24.8	17.8		17.8
Six to ten years	7.3		7.7	1.2		1.2
Greater than ten years	22.8		22.8	9.9		9.6
Total debt securities	\$ 84.0		\$ 84.5	\$ 56.9		\$ 56.6

Sales of Securities: For the three and nine months ended September 30, 2009, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

(Millions of Dollars)	Three Months Ended September 30, 2009			Nine Months Ended September 30, 2009		
	Realized Gains	Realized Losses	Net Realized Gains/(Losses)	Realized Gains	Realized Losses	Net Realized Gains/(Losses)
NU	\$ 5.0	\$ (0.7)	\$ 4.3	\$ 13.3	\$ (5.2)	\$ 8.1
WMECO	-	(0.7)	(0.7)	-	(0.7)	(0.7)

Realized gains and losses on available-for-sale-securities are recorded in Other income, net for the NU supplemental benefit trust and in Deferred debits and other assets - other 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 \$34.4 million and \$182.1 million for the three and nine months ended September 30, 2009, respectively, including \$21.6 million and \$99.9 million, respectively, for WMECO.

SEGMENT INFORMATION (All Companies)

Presentation: NU is organized into two segments; the regulated companies and NU Enterprises businesses, 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 business 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, including the electric distribution and transmission segments, as well as the gas distribution segment (Yankee Gas), represented approximately 99 percent of NU's total consolidated revenues for the three- and nine-month periods ended September 30, 2009 and 2008. CL&P's, PSNH's and WMECO's complete unaudited condensed consolidated financial statements are included in this combined Quarterly Report on Form 10-Q. PSNH's distribution segment includes generation activities. Also included in this combined Quarterly Report on Form 10-Q is detailed information regarding CL&P's, PSNH's, and WMECO's transmission segments.

NU Enterprises is comprised of the following: 1) Select Energy (wholesale contracts), 2) NGS, 3) Boulos, 4) NGS Mechanical, and 5) 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 The Rocky River Realty Company (a real estate subsidiary), Mode 1 Communications, Inc., the results of the non-energy-related subsidiaries of Yankee Energy System, Inc. (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.

NU's segment information for the three and nine months ended September 30, 2009 and 2008 is as follows (certain amounts presented in the financial statements may differ from amounts presented in the segment schedules due to rounding):

For the Three Months Ended September 30, 2009

Regulated Companies

Distribution (1)

(Millions of Dollars)	Electric			NU		Eliminations	Total
	Electric	Gas	Transmission	Enterprises	Other		
Operating revenues	\$ 1,082.0	\$ 60.5	\$ 149.0	\$ 19.6	\$ 95.7	\$ (100.6)	\$ 1,306.2
Depreciation and amortization	(117.2)	(6.6)	(17.8)	(0.1)	(3.1)	0.5	(144.3)
Other operating expenses	(890.1)	(55.7)	(44.5)	(19.0)	(93.9)	103.9	(999.3)
Operating income/(loss)	74.7	(1.8)	86.7	0.5	(1.3)	3.8	162.6
Interest expense, net of AFUDC	(38.1)	(5.5)	(19.2)	(0.5)	(7.7)	1.4	(69.6)
Interest income	0.3	-	0.1	-	1.7	(1.7)	0.4
Other income, net	5.9	0.1	3.1	-	65.5	(65.6)	9.0
Income tax (expense)/benefit	(15.0)	2.7	(27.3)	0.3	4.2	(1.1)	(36.2)
Net income/(loss)	27.8	(4.5)	43.4	0.3	62.4	(63.2)	66.2
Net income attributable to noncontrolling interests	(0.8)	-	(0.6)	-	-	-	(1.4)
Net income/(loss) attributable to controlling interests	27.0	(4.5)	42.8	0.3	62.4	\$ (63.2)	\$ 64.8
	\$	\$	\$	\$	\$		

For the Nine Months Ended September 30, 2009

Regulated Companies

Distribution (1)

(Millions of Dollars)	Electric			NU		Eliminations	Total
	Electric	Gas	Transmission	Enterprises	Other		
Operating revenues	3,335.2	332.5	418.9	61.3	295.9	\$ (319.7)	\$ 4,124.1
	\$	\$	\$	\$	\$		

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Depreciation and amortization	(332.8)	(20.0)	(53.1)	(0.3)	(10.5)	1.8	(414.9)
Other operating expenses	(2,756.8)	(271.3)	(120.8)	(40.6)	(283.4)	322.7	(3,150.2)
Operating income	245.6	41.2	245.0	20.4	2.0	4.8	559.0
Interest expense, net of AFUDC	(112.1)	(16.8)	(53.4)	(2.4)	(25.9)	5.0	(205.6)
Interest income	3.5	-	0.8	-	6.1	(6.0)	4.4
Other income	15.7	0.2	5.6	-	274.7	(274.5)	21.7
Income tax (expense)/benefit	(45.5)	(9.3)	(76.3)	(6.4)	9.5	(2.0)	(130.0)
Net income	107.2	15.3	121.7	11.6	266.4	(272.7)	249.5
Net income attributable to noncontrolling interests	(2.5)	-	(1.7)	-	-	-	(4.2)
Net income attributable to controlling interests	104.7	15.3	120.0	11.6	266.4	\$ (272.7)	\$ 245.3
Total assets	\$ 8,840.5	\$ 1,352.8	\$ 3,124.9	\$ 88.1	\$ 5,911.0	\$ (5,311.0)	\$ 14,006.3
Cash flows for total investments in plant (2)	\$ 374.1	\$ 39.1	\$ 190.5	\$ -	\$ 30.7	\$ -	\$ 634.4

For the Three Months Ended September 30, 2008

Regulated Companies

Distribution (1)

(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	\$ 1,283.8	\$ 92.3	\$ 110.0	\$ 23.1	\$ 106.2	\$ (108.5)	\$ 1,506.9
Depreciation and amortization	(161.9)	(6.7)	(12.8)	(0.2)	(2.8)	0.2	(184.2)
Other operating expenses	(1,044.4)	(84.5)	(36.4)	(16.4)	(96.1)	104.2	(1,173.6)
Operating income	77.5	1.1	60.8	6.5	7.3	(4.1)	149.1
Interest expense, net of AFUDC	(41.8)	(5.1)	(14.4)	(1.3)	(10.9)	2.6	(70.9)
Interest income	11.1	0.4	0.2	0.4	2.5	(2.6)	12.0
Other income, net	(0.6)	-	6.4	-	33.0	(33.1)	5.7
Income tax (expense)/benefit	(7.5)	1.3	(16.6)	(1.0)	2.0	-	(21.8)
Net income/(loss)	38.7	(2.3)	36.4	4.6	33.9	(37.2)	74.1

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Net income attributable to noncontrolling interests	(0.9)	-	(0.5)	-	-	-	(1.4)
Net income/(loss) attributable to controlling interests	37.8	(2.3)	35.9	4.6	33.9	\$ (37.2)	\$ 72.7
	\$	\$	\$	\$	\$		

For the Nine Months Ended September 30, 2008

Regulated Companies

Distribution (1)

(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	\$ 3,580.6	\$ 404.9	\$ 306.3	\$ 87.0	\$ 306.3	\$ (332.9)	\$ 4,352.2
Depreciation and amortization	(427.7)	(19.7)	(35.1)	(0.4)	(10.0)	0.6	(492.3)
Other operating expenses	(2,915.0)	(346.1)	(101.6)	(70.8)	(332.2)	325.3	(3,440.4)
Operating income/(loss)	237.9	39.1	169.6	15.8	(35.9)	(7.0)	419.5
Interest expense, net of AFUDC	(122.0)	(15.2)	(39.7)	(4.3)	(25.9)	7.5	(199.6)
Interest income	12.9	0.4	2.3	0.9	6.4	(8.4)	14.5
Other income, net	4.8	0.1	22.1	-	143.4	(143.3)	27.1
Income tax (expense)/benefit	(31.3)	(9.1)	(49.2)	(3.7)	26.0	(1.1)	(68.4)
Net income	102.3	15.3	105.1	8.7	114.0	(152.3)	193.1
Net income attributable to noncontrolling interests	(2.7)	-	(1.5)	-	-	-	(4.2)
Net income attributable to controlling interests	99.6	15.3	103.6	8.7	114.0	\$ (152.3)	\$ 188.9
Cash flows for total investments in plant (2)	\$ 326.3	\$ 39.1	\$ 566.7	\$ -	\$ 19.7	\$ -	\$ 951.8

(1)

Includes PSNH's generation activities.

(2)

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Cash flows for total investments in plant included in the segment information above 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 information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the three and nine months ended September 30, 2009 and 2008 is as follows:

CL&P - For the Three Months Ended September 30, 2009

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 741.2	\$ 118.1	\$ 859.3
Depreciation and amortization	(80.9)	(14.5)	(95.4)
Other operating expenses	(619.8)	(34.0)	(653.8)
Operating income	40.5	69.6	110.1
Interest expense, net of AFUDC	(24.3)	(16.5)	(40.8)
Interest income	0.6	0.1	0.7
Other income, net	3.8	2.5	6.3
Income tax expense	(8.4)	(21.4)	(29.8)
Net income	\$ 12.2	\$ 34.3	\$ 46.5

CL&P - For the Nine Months Ended September 30, 2009

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 2,258.5	\$ 340.2	\$ 2,598.7
Depreciation and amortization	(238.5)	(43.8)	(282.3)
Other operating expenses	(1,881.7)	(91.1)	(1,972.8)
Operating income	138.3	205.3	343.6
Interest expense, net of AFUDC	(69.9)	(46.3)	(116.2)
Interest income	1.9	0.7	2.6
Other income, net	11.1	4.2	15.3
Income tax expense	(23.9)	(63.3)	(87.2)
Net income	\$ 57.5	\$ 100.6	\$ 158.1
Total assets	\$ 5,782.7	\$ 2,487.8	\$ 8,270.5
Cash flows for total investments in plant (2)	\$ 209.9	\$ 121.7	\$ 331.6

CL&P - For the Three Months Ended September 30, 2008

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 891.0	\$ 89.5	\$ 980.5
Depreciation and amortization	(123.9)	(10.3)	(134.2)
Other operating expenses	(720.6)	(27.5)	(748.1)
Operating income	46.5	51.7	98.2
Interest expense, net of AFUDC	(25.7)	(12.4)	(38.1)
Interest income	7.3	0.5	7.8
Other income, net	(0.2)	5.4	5.2
Income tax expense	(3.5)	(14.1)	(17.6)
Net income	\$ 24.4	\$ 31.1	\$ 55.5

CL&P - For the Nine Months Ended September 30, 2008

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 2,444.8	\$ 243.1	\$ 2,687.9
Depreciation and amortization	(332.7)	(27.9)	(360.6)
Other operating expenses	(1,975.5)	(74.2)	(2,049.7)
Operating income	136.6	141.0	277.6
Interest expense, net of AFUDC	(75.4)	(34.1)	(109.5)
Interest income	8.6	1.8	10.4
Other income, net	4.7	19.7	24.4
Income tax expense	(14.6)	(40.4)	(55.0)
Net income	\$ 59.9	\$ 88.0	\$ 147.9
Cash flows for total investments in plant (2)	\$ 200.6	\$ 478.0	\$ 678.6

PSNH - For the Three Months Ended September 30, 2009

(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	\$ 254.7	\$ 20.4	\$ 275.1
Depreciation and amortization	(28.4)	(2.4)	(30.8)
Other operating expenses	(202.6)	(7.6)	(210.2)
Operating income	23.7	10.4	34.1
Interest expense, net of AFUDC	(9.9)	(1.8)	(11.7)
Interest income	0.4	-	0.4
Other income, net	1.5	0.4	1.9

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Income tax expense	(5.0)	(3.5)	(8.5)
Net income	\$ 10.7	\$ 5.5	\$ 16.2

PSNH - For the Nine Months Ended September 30, 2009

(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	\$ 792.2	\$ 53.5	\$ 845.7
Depreciation and amortization	(73.0)	(6.8)	(79.8)
Other operating expenses	(644.0)	(20.5)	(664.5)
Operating income	75.2	26.2	101.4
Interest expense, net of AFUDC	(30.0)	(4.8)	(34.8)
Interest income	2.1	0.1	2.2
Other income, net	3.2	1.1	4.3
Income tax expense	(14.3)	(8.5)	(22.8)
Net income	\$ 36.2	\$ 14.1	\$ 50.3
Total assets	\$ 2,179.5	\$ 429.8	\$ 2,609.3
Cash flows for total investments in plant (2)	\$ 134.7	\$ 34.7	\$ 169.4

PSNH - For the Three Months Ended September 30, 2008

(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	\$ 286.9	\$ 14.1	\$ 301.0
Depreciation and amortization	(26.5)	(1.9)	(28.4)
Other operating expenses	(237.1)	(6.1)	(243.2)
Operating income	23.3	6.1	29.4
Interest expense, net of AFUDC	(11.8)	(1.6)	(13.4)
Interest income	2.3	-	2.3
Other income, net	(0.2)	0.6	0.4
Income tax expense	(2.9)	(1.5)	(4.4)
Net income	\$ 10.7	\$ 3.6	\$ 14.3

PSNH - For the Nine Months Ended September 30, 2008

(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	\$ 822.8	\$ 44.0	\$ 866.8
Depreciation and amortization	(61.2)	(5.3)	(66.5)
Other operating expenses	(687.6)	(18.4)	(706.0)
Operating income	74.0	20.3	94.3
Interest expense, net of AFUDC	(33.6)	(3.9)	(37.5)
Interest income	2.6	0.4	3.0
Other income, net	0.4	1.9	2.3
Income tax expense	(11.1)	(6.3)	(17.4)
Net income	\$ 32.3	\$ 12.4	\$ 44.7
Cash flows for total investments in plant (2)	\$ 101.5	\$ 63.3	\$ 164.8

WMECO - For the Three Months Ended September 30, 2009

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 86.2	\$ 10.4	\$ 96.6
Depreciation and amortization	(7.9)	(0.8)	(8.7)
Other operating expenses	(67.8)	(3.0)	(70.8)
Operating income	10.5	6.6	17.1
Interest expense, net of AFUDC	(4.0)	(0.8)	(4.8)
Interest income	(0.6)	-	(0.6)
Other income, net	0.7	0.1	0.8

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Income tax expense		(1.7)		(2.3)		(4.0)
Net income	\$	4.9	\$	3.6	\$	8.5

WMECO - For the Nine Months Ended September 30, 2009

(Millions of Dollars)		Distribution		Transmission		Total
Operating revenues	\$	284.6	\$	25.2	\$	309.8
Depreciation and amortization		(21.4)		(2.4)		(23.8)
Other operating expenses		(231.2)		(9.2)		(240.4)
Operating income		32.0		13.6		45.6
Interest expense, net of AFUDC		(12.2)		(2.3)		(14.5)
Interest income		(0.4)		-		(0.4)
Other income, net		1.3		0.3		1.6
Income tax expense		(7.2)		(4.6)		(11.8)
Net income	\$	13.5	\$	7.0	\$	20.5
Total assets	\$	859.8	\$	212.9	\$	1,072.7
Cash flows for total investments in plant (2)	\$	29.6	\$	34.1	\$	63.7

WMECO - For the Three Months Ended September 30, 2008

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 105.9	\$ 6.4	\$ 112.3
Depreciation and amortization	(11.4)	(0.7)	(12.1)
Other operating expenses	(86.8)	(2.6)	(89.4)
Operating income	7.7	3.1	10.8
Interest expense, net of AFUDC	(4.3)	(0.4)	(4.7)
Interest income	1.4	(0.3)	1.1
Other income, net	(0.2)	0.3	0.1
Income tax expense	(1.0)	(1.1)	(2.1)
Net income	\$ 3.6	\$ 1.6	\$ 5.2

WMECO - For the Nine Months Ended September 30, 2008

(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	\$ 313.2	\$ 19.1	\$ 332.3
Depreciation and amortization	(33.8)	(2.0)	(35.8)
Other operating expenses	(252.1)	(8.8)	(260.9)
Operating income	27.3	8.3	35.6
Interest expense, net of AFUDC	(13.1)	(1.6)	(14.7)
Interest income	1.7	-	1.7
Other income, net	(0.2)	0.5	0.3
Income tax expense	(5.6)	(2.5)	(8.1)
Net income	\$ 10.1	\$ 4.7	\$ 14.8
Cash flows for total investments in plant (2)	\$ 24.2	\$ 25.4	\$ 49.6

(1)

Includes PSNH's generation activities.

(2)

Cash flows for total investments in plant included in the segment information above 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.

12.

COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST (NU)

A summary of the changes in common shareholders' equity and noncontrolling interest of NU for the three and nine months ended September 30, 2009 and 2008 is as follows:

	For the Three Months Ended September 30,		2008	
	2009		2008	
(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Common Shareholders' Equity	Noncontrolling Interest
Balance, beginning of period	\$ 3,501.8	\$ 116.2	\$ 2,939.5	\$ 116.2
Net income	66.2	-	74.1	-
Dividends on common shares	(41.9)	-	-	-
Dividends on preferred shares of CL&P	(1.4)	(1.4)	(1.4)	(1.4)
Other transactions, net	7.5	-	5.7	-
Net income attributable to noncontrolling interests	-	1.4	-	1.4
Other comprehensive income/(loss) (Note 6)	1.2	-	(1.9)	-
Balance, end of period	\$ 3,533.4	\$ 116.2	\$ 3,016.0	\$ 116.2

	For the Nine Months Ended September 30,			
	2009		2008	
(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Common Shareholders' Equity	Noncontrolling Interest
Balance, beginning of period	\$ 3,020.3	\$ 116.2	\$ 2,913.8	\$ 116.2
Net income	249.5	-	193.1	-
Dividends on common shares	(121.0)	-	(95.7)	-
Dividends on preferred shares of CL&P	(4.2)	(4.2)	(4.2)	(4.2)
Issuance of common shares	388.5	-	5.0	-
Capital stock expenses, net	(12.5)	-	-	-
Other transactions, net	13.3	-	10.5	-
Net income attributable to noncontrolling interests	-	4.2	-	4.2
Other comprehensive loss (Note 6)	(0.5)	-	(6.5)	-
Balance, end of period	\$ 3,533.4	\$ 116.2	\$ 3,016.0	\$ 116.2

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Northeast Utilities:

We have reviewed the accompanying condensed consolidated balance sheet of Northeast Utilities and subsidiaries (the "Company") as of September 30, 2009, and the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2009 and 2008, and of cash flows for the nine-month periods ended September 30, 2009 and 2008. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and consolidated statement of capitalization of Northeast Utilities and subsidiaries as of December 31, 2008, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended prior to retrospective adjustment to reflect new accounting guidance for non-controlling interests in consolidated financial statements, (not presented herein); and in our report dated February 27, 2009 (which report included an explanatory paragraph related to the adoption of new accounting guidance for fair value measurements, as of January 1, 2008), we expressed an unqualified opinion on those consolidated financial statements. We also audited the adjustments described in Note 1 that were applied to retrospectively adjust the December 31, 2008 consolidated balance sheet of Northeast Utilities and subsidiaries (not presented herein). In our opinion, such adjustments are appropriate and have been properly applied to the previously issued consolidated balance sheet in deriving the accompanying retrospectively adjusted condensed consolidating balance sheet as of December 31, 2008.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

November 6, 2009

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER
COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>ASSETS</u>		
Current Assets:		
Cash	\$ 2,221	\$ -
Receivables, less provision for uncollectible accounts of \$29,285 in 2009 and \$23,956 in 2008	375,074	416,304
Accounts receivable from affiliated companies	1,529	11,215
Notes receivable from affiliated companies	89,975	-
Unbilled revenues	105,247	127,844
Materials and supplies - current	65,604	70,676
Derivative assets - current	13,795	30,478
Prepayments and other	31,214	15,685
	684,659	672,202
Property, Plant and Equipment:		
Electric utility	6,417,044	6,244,705
Less: Accumulated depreciation	1,414,809	1,346,062
	5,002,235	4,898,643
Construction work in progress	260,607	190,481
	5,262,842	5,089,124
Deferred Debits and Other Assets:		
Regulatory assets	2,020,036	2,274,088
Derivative assets - long-term	207,004	215,288
Other	95,955	85,416
	2,322,995	2,574,792

Total Assets	\$	8,270,496	\$	8,336,118
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

THE CONNECTICUT LIGHT AND POWER
COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to banks	\$ 32,991	\$ 187,973
Notes payable to affiliated companies	-	102,725
Long-term debt - current portion	62,000	-
Accounts payable	212,997	353,584
Accounts payable to affiliated companies	32,561	57,053
Accrued taxes	74,968	24,839
Accrued interest	45,388	37,567
Derivative liabilities - current	8,368	8,873
Other	85,206	92,444
	554,479	865,058
Rate Reduction Bonds	240,336	378,195
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	882,914	811,405
Accumulated deferred investment tax credits	16,968	18,805
Deferred contractual obligations	119,379	132,687
Regulatory liabilities	325,397	363,547
Derivative liabilities - long-term	810,816	848,106
Accrued pension	72,053	89,254
Accrued postretirement benefits	90,466	98,587
Other	207,657	215,620
	2,525,650	2,578,011
Capitalization:		
Long-Term Debt	2,520,194	2,270,414

Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common stock, \$10 par value - authorized 24,500,000 shares; 6,035,205 shares outstanding		
in 2009 and 2008	60,352	60,352
Capital surplus, paid in	1,570,740	1,454,198
Retained earnings	685,819	617,276
Accumulated other comprehensive loss	(3,274)	(3,586)
Common Stockholder's Equity	2,313,637	2,128,240
Total Capitalization	4,950,031	4,514,854
		\$
Total Liabilities and Capitalization	\$ 8,270,496	8,336,118

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF INCOME
 (Unaudited)

(Thousands of Dollars)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating Revenues	\$ 859,283	\$ 980,507	\$ 2,598,723	\$ 2,687,881
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	419,620	522,613	1,317,159	1,414,506
Other	149,302	140,727	419,887	402,099
Maintenance	31,215	35,863	86,113	98,297
Depreciation	46,519	40,740	140,000	119,464
Amortization of regulatory assets, net	7,911	55,105	24,551	131,093
Amortization of rate reduction bonds	40,976	38,353	117,725	110,033
Taxes other than income taxes	53,648	48,953	149,736	134,787
Total operating expenses	749,191	882,354	2,255,171	2,410,279
Operating Income	110,092	98,153	343,552	277,602
Interest Expense:				
Interest on long-term debt	33,514	28,053	99,486	77,052
Interest on rate reduction bonds	4,455	6,997	15,342	22,808
Other interest	2,838	3,074	1,420	9,635
Interest expense, net	40,807	38,124	116,248	109,495
Other Income, Net	7,070	13,059	17,948	34,757
Income Before Income Tax Expense	76,355	73,088	245,252	202,864

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Income Tax Expense	29,818	17,553	87,178	55,006
			\$	\$
Net Income	\$ 46,537	\$ 55,535	158,074	147,858

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

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

(Unaudited)

Nine Months Ended September 30,

(Thousands of Dollars)

2009

2008

Operating Activities:

		\$
Net income	\$ 158,074	147,858
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Bad debt expense	11,170	5,450
Depreciation	140,000	119,464
Deferred income taxes	34,458	18,313
Allowance for equity funds used during construction	(3,533)	(19,352)
Pension income and PBOP expense, net of capitalized portion, and contributions	(4,329)	(16,839)
Regulatory overrecoveries/(refunds and underrecoveries), net	51,378	(99,900)
Amortization of regulatory assets, net	24,551	131,093
Amortization of rate reduction bonds	117,725	110,033
Deferred contractual obligations	(14,059)	(16,967)
Other	(7,860)	(12,276)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	52,715	(68,702)
Investments in securitizable assets	-	(25,787)
Materials and supplies	(6,205)	(13,700)
Other current assets	(15,395)	(18,642)
Accrued taxes	63,404	102,146
Accounts payable	(121,852)	(25,626)
Other current liabilities	1,421	14,468
Net cash flows provided by operating activities	481,663	331,034

Investing Activities:

Investments in property and plant	(331,644)	(678,616)
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Increase in NU Money Pool lending	(89,975)	(16,075)
Other investing activities	1,630	(1,033)
Net cash flows used in investing activities	(419,989)	(695,724)
Financing Activities:		
Cash dividends on common stock	(85,386)	(79,846)
Cash dividends on preferred stock	(4,169)	(4,169)
(Decrease)/increase in short-term debt	(154,982)	187,973
Decrease in NU Money Pool borrowings	(102,725)	(38,825)
Capital contributions from NU parent	116,591	137,430
Issuance of long-term debt	312,000	300,000
Retirements of rate reduction bonds	(137,859)	(128,852)
Other financing activities	(2,923)	(3,463)
Net cash flows (used in)/provided by financing activities	(59,453)	370,248
Net increase in cash	2,221	5,558
Cash - beginning of period	-	538
		\$
Cash - end of period	\$ 2,221	6,096

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW
HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>ASSETS</u>		
Current Assets:		
Cash	\$ 1,175	\$ 195
Receivables, less provision for uncollectible accounts of \$5,050 in 2009 and \$4,165 in 2008	115,442	108,857
Notes receivable from affiliated companies	-	53,800
Accounts receivable from affiliated companies	4,989	264
Unbilled revenues	40,062	41,449
Taxes receivable	7,194	8,809
Fuel, materials and supplies - current	123,780	113,121
Accumulated deferred income taxes - current	15,741	27,345
Prepayments and other	5,454	16,223
	313,837	370,063
Property, Plant and Equipment:		
Electric utility	2,370,339	2,238,515
Less: Accumulated depreciation	799,680	771,282
	1,570,659	1,467,233
Construction work in progress	158,555	113,752
	1,729,214	1,580,985
Deferred Debits and Other Assets:		
Regulatory assets	506,681	549,934
Other	59,551	127,851
	566,232	677,785

Total Assets	\$	2,609,283	\$	2,628,833
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW
HAMPSHIRE AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to banks	\$ 45,227	\$ 45,227
Notes payable to affiliated companies	12,700	-
Accounts payable	114,284	160,692
Accounts payable to affiliated companies	13,401	31,140
Accrued interest	14,999	11,778
Derivative liabilities - current	40,651	77,369
Other	28,829	23,422
	270,091	349,628
Rate Reduction Bonds	200,624	235,139
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	263,273	253,670
Accumulated deferred investment tax credits	247	355
Deferred contractual obligations	21,215	23,820
Regulatory liabilities	99,407	111,403
Derivative liabilities - long-term	10,210	14,846
Accrued pension	248,240	236,332
Accrued postretirement benefits	38,654	41,849
Other	48,175	41,297
	729,421	723,572
Capitalization:		
Long-Term Debt	686,818	686,779
Common Stockholder's Equity:		

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Common stock, \$1 par value - authorized 100,000,000 shares; 301 shares outstanding in 2009 and 2008	-	-
Capital surplus, paid in	420,151	351,245
Retained earnings	302,898	283,219
Accumulated other comprehensive loss	(720)	(749)
Common Stockholder's Equity	722,329	633,715
Total Capitalization	1,409,147	1,320,494

Total Liabilities and Capitalization	\$	2,609,283	\$	2,628,833
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND
SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(Thousands of Dollars)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating Revenues	\$ 275,135	\$ 301,033	\$ 845,719	\$ 866,837
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	120,437	159,255	395,156	443,690
Other	55,038	46,159	176,242	155,266
Maintenance	22,327	26,814	58,701	75,987
Depreciation	15,567	14,331	46,128	41,553
Amortization of regulatory assets/(liabilities), net	3,157	2,671	(1,656)	(9,240)
Amortization of rate reduction bonds	12,123	11,439	35,337	34,186
Taxes other than income taxes	12,361	11,000	34,374	31,121
Total operating expenses	241,010	271,669	744,282	772,563
Operating Income	34,125	29,364	101,437	94,274
Interest Expense:				
Interest on long-term debt	8,181	9,089	24,551	24,088
Interest on rate reduction bonds	3,146	3,948	10,210	12,180
Other interest	371	362	34	1,252
Interest expense, net	11,698	13,399	34,795	37,520
Other Income, Net	2,239	2,706	6,469	5,294

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Income Before Income Tax Expense	24,666	18,671	73,111	62,048
Income Tax Expense	8,463	4,353	22,843	17,350
Net Income	\$ 16,203	\$ 14,318	\$ 50,268	\$ 44,698

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

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

(Unaudited)

	Nine Months Ended September 30,	
(Thousands of Dollars)	2009	2008
Operating activities:		
Net income	\$ 50,268	\$ 44,698
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Bad debt expense	7,014	3,992
Depreciation	46,128	41,553
Deferred income taxes	16,852	10,164
Pension and PBOP expense, net of capitalized portion, and contributions	13,137	7,539
Regulatory underrecoveries, net	(10,316)	(3,873)
Amortization of regulatory liabilities, net	(1,656)	(9,240)
Amortization of rate reduction bonds	35,337	34,186
Deferred contractual obligations	(2,917)	(4,064)
Proceeds from insurance settlement for operating portion of major storm cost recovery	10,066	-
Other	(3,206)	(16,759)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(6,937)	(6,012)
Taxes receivable	1,934	(14,901)
Fuel, materials and supplies	878	1,725
Other current assets	10,771	20
Accounts payable	(77,433)	(933)
Accrued interest	3,221	8,009
Other current liabilities	8,035	3,627
Net cash flows provided by operating activities	101,176	99,731
Investing Activities:		
Investments in property and plant	(169,434)	(164,757)

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Decrease/(increase) in NU Money Pool lending	53,800	(6,100)
Other investing activities	(759)	2,467
Net cash flows used in investing activities	(116,393)	(168,390)
Financing Activities:		
Cash dividends on common stock	(30,633)	(27,282)
Decrease in short-term debt	-	(10,000)
Issuance of long-term debt	-	110,000
Increase/(decrease) in NU Money Pool borrowings	12,700	(11,300)
Capital contributions from NU parent	68,946	46,583
Retirements of rate reduction bonds	(34,515)	(35,060)
Other financing activities	(301)	(1,625)
Net cash flows provided by financing activities	16,197	71,316
Net increase in cash	980	2,657
Cash - beginning of period	195	450
		\$
Cash - end of period	\$ 1,175	3,107

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>ASSETS</u>		
Current Assets:		
Cash	\$ 1	\$ -
Receivables, less provision for uncollectible accounts of \$7,524 in 2009 and \$6,571 in 2008	42,648	56,802
Accounts receivable from affiliated companies	555	575
Unbilled revenues	12,799	16,694
Taxes receivable	2,689	5,499
Materials and supplies - current	3,701	3,825
Marketable securities - current	27,967	46,428
Prepayments and other	1,704	2,380
	92,064	132,203
Property, Plant and Equipment:		
Electric utility	823,230	781,486
Less: Accumulated depreciation	221,987	214,694
	601,243	566,792
Construction work in progress	77,777	57,413
	679,020	624,205
Deferred Debits and Other Assets:		
Regulatory assets	248,661	268,417
Marketable securities - long-term	28,660	9,322
Other	24,280	14,342
	301,601	292,081

Total Assets	\$	1,072,685	\$	1,048,489
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE
SHEETS

(Unaudited)

(Thousands of Dollars)	September 30, 2009	December 31, 2008
<u>LIABILITIES AND CAPITALIZATION</u>		
Current Liabilities:		
Notes payable to banks	\$ 75,077	\$ 29,850
Notes payable to affiliated companies	36,200	31,600
Accounts payable	35,716	50,161
Accounts payable to affiliated companies	6,421	15,047
Accrued interest	1,773	5,824
Other	11,852	10,715
	167,039	143,197
Rate Reduction Bonds	62,343	73,176
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	205,718	187,283
Accumulated deferred investment tax credits	1,562	1,753
Deferred contractual obligations	32,857	36,509
Regulatory liabilities	23,572	29,826
Accrued postretirement benefits	16,967	18,078
Other	12,538	16,649
	293,214	290,098
Capitalization:		
Long-Term Debt	305,448	303,868
Common Stockholder's Equity:		
Common stock, \$25 par value - authorized		
1,072,471 shares; 434,653 shares		
outstanding		

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in 2009 and 2008	10,866	10,866
Capital surplus, paid in	145,394	144,545
Retained earnings	88,366	82,549
Accumulated other comprehensive income	15	190
Common Stockholder's Equity	244,641	238,150
Total Capitalization	550,089	542,018

Total Liabilities and Capitalization	\$ 1,072,685	\$ 1,048,489
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The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND
SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(Thousands of Dollars)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	\$	\$	\$	\$
Operating Revenues	96,622	112,280	309,823	332,254
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	42,403	64,146	151,936	177,640
Other	19,022	16,255	64,503	57,830
Maintenance	5,196	5,807	13,437	15,856
Depreciation	5,609	5,183	16,758	15,627
Amortization of regulatory (liabilities)/assets, net	(430)	3,541	(3,769)	9,950
Amortization of rate reduction bonds	3,569	3,341	10,809	10,148
Taxes other than income taxes	4,104	3,236	10,518	9,610
Total operating expenses	79,473	101,509	264,192	296,661
Operating Income	17,149	10,771	45,631	35,593
Interest Expense:				
Interest on long-term debt	3,534	3,278	10,531	9,964
Interest on rate reduction bonds	1,057	1,262	3,337	3,922
Other interest	238	197	632	822
Interest expense, net	4,829	4,737	14,500	14,708
Other Income, Net	160	1,329	1,095	2,053

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Income Before Income				
Tax Expense	12,480	7,363	32,226	22,938
Income Tax Expense	3,971	2,127	11,764	8,133
	\$	\$	\$	\$
Net Income	8,509	5,236	20,462	14,805

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

WESTERN MASSACHUSETTS ELECTRIC
COMPANY AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS
OF CASH FLOWS

(Unaudited)

(Thousands of Dollars)	Nine Months Ended September 30,	
	2009	2008
Operating Activities:		
Net income	\$ 20,462	\$ 14,805
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Bad debt expense	5,858	6,123
Depreciation	16,758	15,627
Deferred income taxes	17,227	6,487
Pension income and PBOP expense, net of capitalized portion, and contributions	(6,840)	(4,187)
Regulatory overrecoveries/(underrecoveries), net	3,083	(1,317)
Amortization of regulatory (liabilities)/assets, net	(3,769)	9,950
Amortization of rate reduction bonds	10,809	10,148
Deferred contractual obligations	(3,840)	(4,573)
Other	260	(3,647)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	4,633	(3,171)
Materials and supplies	124	(1,645)
Other current assets	1,016	(1,578)
Accounts payable	(27,176)	4,456
Taxes receivable/accrued	5,616	(5,998)
Other current liabilities	(5,720)	(2,115)
Net cash flows provided by operating activities	38,501	39,365
Investing Activities:		
Investments in property and plant	(63,726)	(49,634)
Proceeds from sales of marketable securities	99,898	136,169
Purchases of marketable securities	(100,413)	(136,763)
Other investing activities	581	489

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Net cash flows used in investing activities	(63,660)	(49,739)
Financing Activities:		
Cash dividends on common stock	(14,652)	(10,105)
Increase in short-term debt	45,227	19,900
Retirements of rate reduction bonds	(10,833)	(10,178)
Increase/(decrease) in NU Money Pool borrowings	4,600	(4,000)
Capital contributions from NU parent	864	16,281
Other financing activities	(46)	-
Net cash flows provided by financing activities	25,160	11,898
Net increase in cash	1	1,524
Cash - beginning of period	-	1,110
		\$
Cash - end of period	\$ 1	2,634

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

NORTHEAST UTILITIES AND SUBSIDIARIES

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

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and related combined notes included in this Quarterly Report on Form 10-Q, the Northeast Utilities and subsidiaries combined Quarterly Reports on Form 10-Q for the first and second quarters of 2009 (2009 Forms 10-Q) and the Northeast Utilities and subsidiaries combined 2008 Annual Report on Form 10-K as filed with the Securities and Exchange Commission (SEC) (2008 Form 10-K). References in this Form 10-Q to "NU," the "Company," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a fully diluted basis.

The only common equity securities that are publicly traded are common shares of NU. The earnings and earnings per share (EPS) of each segment discussed below do not represent a direct legal interest in the assets and liabilities allocated to such segment but rather represent a direct interest in our assets and liabilities as a whole. EPS by segment is a financial measure not recognized under accounting principles generally accepted in the United States of America (GAAP) that is calculated by dividing the net income or loss attributable to controlling interests of each segment by the weighted average fully diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to provide segmented earnings results and guidance and believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our business segments. This non-GAAP financial measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes non-GAAP financial measures referencing 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 explain and compare the 2009 and 2008 results without including the impact of this settlement. Due to the nature and significance of the litigation settlement charge, 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 fully 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 this Management's Discussion and Analysis.

Forward-Looking Statements: This Management's Discussion and Analysis includes statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, future financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our "forward-looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results.

Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to, actions or inaction of local, state and federal regulatory and taxing bodies, changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports filed with the SEC 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 of which speaks only as of the date on which such statement is made, and we undertake no obligation to update the information contained in 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 our 2008 Form 10-K and updated in this Quarterly Report and our other 2009 Forms 10-Q. This Quarterly Report on Form 10-Q, our

2008 Form 10-K and our 2009 Forms 10-Q also describe material contingencies and critical accounting policies and estimates in the respective "Management's Discussion and Analysis" and "Combined Notes to Consolidated Financial Statements." We encourage you to review these items.

Financial Condition and Business Analysis

Executive Summary

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

Results, Strategy and Outlook:

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We earned \$64.8 million, or \$0.37 per share, in the third quarter of 2009 and \$245.3 million, or \$1.43 per share, in the first nine months of 2009, compared with \$72.7 million, or \$0.47 per share, in the third quarter of 2008 and \$188.9 million, or \$1.21 per share, in the first nine months of 2008. The decrease in 2009 third quarter results was due primarily to greater income tax expense as a result of lower tax benefits (and a higher effective income tax rate) from reduced capital expenditures and the absence of a benefit from the resolution of routine federal and state tax matters in 2008, as well as higher expenses related to uncollectible receivable balances. The results for the first nine months of 2009 were also impacted by a higher effective income tax rate from lower tax benefits as a result of reduced capital expenditures. The EPS for 2009 also reflects the issuance of approximately 19 million common shares on March 20, 2009. Results for the first nine months of 2008 included an after-tax charge of \$29.8 million, or \$0.19 per share, associated with the settlement of litigation.

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Our regulated companies, which consist of The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Yankee Gas Services Company (Yankee Gas), earned \$65.3 million, or \$0.37 per share, in the third quarter of 2009 and \$240 million, or \$1.40 per share, in the first nine months of 2009, compared with \$71.4 million, or \$0.46 per share, in the third quarter of 2008 and \$218.5 million, or \$1.40 per share, in the first nine months of 2008. The 2009 third quarter and year-to-date results were impacted by greater income tax expense for the reasons described above and higher expenses related to uncollectible receivable balances, partially offset by recognition of gains on securities in the NU Trust Under Supplemental Executive Retirement Plan (NU supplemental benefit trust).

Earnings at the distribution segments of our regulated companies (which include Yankee Gas and the generation business of PSNH) totaled \$22.5 million in the third quarter of 2009 and \$120 million in the first nine months of 2009, compared with \$35.5 million in the third quarter of 2008 and \$114.9 million in the first nine months of 2008.

Earnings at the transmission segments of our regulated companies totaled \$42.8 million in the third quarter of 2009 and \$120 million in the first nine months of 2009, compared with \$35.9 million in the third quarter of 2008 and \$103.6 million in the first nine months of 2008.

Our competitive businesses held by NU Enterprises, Inc. (NU Enterprises) earned \$0.3 million in the third quarter of 2009 and \$11.6 million, or \$0.07 per share, in the first nine months of 2009, compared with \$4.6 million, or \$0.03 per share, in the third quarter of 2008 and \$8.7 million, or \$0.05 per share, in the first nine months of 2008. Year-to-date 2009 results included an after-tax mark-to-market gain of \$3.7 million associated with wholesale marketing contracts.

The first nine months of 2008 results included a net after-tax charge to earnings of \$2.8 million associated with the implementation of accounting guidance for fair value measurements and an after-tax mark-to-market gain of \$2.7 million. Third quarter 2009 results included an after-tax mark-to-market loss of \$0.9 million, as compared to an after-tax mark-to-market gain of \$3.6 million in the third quarter of 2008.

NU parent and other companies recorded net expenses of \$0.8 million in the third quarter of 2009 and \$6.3 million, or \$0.04 per share, in the first nine months of 2009, compared with net expenses of \$3.3 million, or \$0.02 per share, in the third quarter of 2008 and \$38.3 million, or \$0.24 per share, in the first nine months of 2008. Results for the first nine months of 2008 included the after-tax charge of \$29.8 million associated with the settlement of litigation.

We continue to project consolidated 2009 earnings of between \$1.80 per share and \$1.90 per share. We project consolidated 2010 earnings of between \$1.80 per share and \$2.00 per share, including distribution segment earnings of between \$0.95 per share and \$1.05 per share, transmission segment earnings of between \$0.90 per share and \$0.95 per share, competitive business earnings of between \$0.00 per share and \$0.05 per share, and net expenses at NU parent and other companies of approximately \$0.05 per share. PSNH filed a distribution rate case in June 2009 and CL&P plans to file a distribution rate case in late 2009 or early 2010. There are uncertainties in the distribution segment guidance over the outcomes of these distribution rate cases, both of which are expected to conclude in mid-2010. The filing of a distribution rate case for Yankee Gas is also under consideration but additional earnings from such a filing are not included in the 2010 projection. We also project that we will achieve a compound average annual EPS growth rate for the five-year period of 2010 to 2014 of between 6 percent and 9 percent, using 2009 projected EPS as the base level. We had

previously estimated a compound average annual EPS growth rate at the low end of an 8 percent to 11 percent range from 2009 to 2013, using 2007 EPS as the base level. Refer to "Future Outlook" in this Management's Discussion and Analysis for further discussion.

Regulated company capital expenditures are expected to total approximately \$6.4 billion from 2010 through 2014, which would enable our total rate base to grow at a compound average annual growth rate of 9.5 percent from approximately \$7.1 billion at the end of 2009 to \$11.1 billion at the end of 2014. This projection assumes the projects we have included in our five-year plan are built according to our schedule and on budget.

Legal, Regulatory and Other Items:

On August 6, 2009, CL&P, PSNH, and WMECO filed an application with the U.S. Department of Energy (DOE) seeking federal stimulus funding for 50 percent of \$253 million in capital investment programs, including the installation of smart grid technology in Connecticut, New Hampshire and Massachusetts. The DOE elected not to approve this application in October 2009. We continue to proceed with the smart meter initiatives at CL&P and WMECO further described below.

On August 12, 2009, the Massachusetts Department of Public Utilities (DPU) approved the installation of 6 megawatts (MW) of solar energy generation in WMECO's service territory at an estimated cost of \$41 million. These generation facilities are expected to be commissioned beginning in 2010, and the return on equity (ROE) on these assets will be 9 percent.

On August 31, 2009, CL&P completed a three-month dynamic pricing smart meter pilot program that involved nearly 3,000 customers. CL&P is required to file a report on the results of the pilot with the Connecticut Department of Public Utility Control (DPUC) on December 1, 2009. In the first quarter of 2010, CL&P expects to file an Advanced Metering Infrastructure (AMI) deployment recommendation with the DPUC.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. The program proposes to involve 1,750 customers in WMECO's service region for a term of six months beginning in April 2011. The total cost of the project is projected to be \$7 million, which would be recovered through WMECO rates. A decision is expected from the DPU in the first half of 2010.

Liquidity:

On October 5, 2009, the New Hampshire Public Utilities Commission (NHPUC) approved an application by PSNH to issue \$150 million of first mortgage bonds and increase its short-term debt limit to \$60 million above the statutory limit of 10 percent of net plant, which represents approximately \$157 million. We currently expect PSNH to issue the bonds by the end of 2009.

We expect to issue an aggregate amount of approximately \$340 million of long-term debt in 2010 (\$170 million at PSNH, \$90 million at WMECO and \$80 million at Yankee Gas). We currently anticipate a single public offering of approximately \$300 million in NU common shares in the next five years, which is expected no earlier than 2012.

Primarily as a result of NU's March 2009 common share offering and CL&P's February 2009 first mortgage bond issuance, which resulted in total gross proceeds of approximately \$630 million, our cash and cash equivalents totaled \$249 million as of September 30, 2009, compared with \$89.8 million as of December 31, 2008. As of September 30, 2009, we also had \$446.9 million of aggregate borrowing availability on our revolving credit lines, as compared to \$157.8 million of availability as of December 31, 2008.

Our cash capital expenditures totaled \$634.4 million in the first nine months of 2009, compared with \$951.8 million in the first nine months of 2008. The decrease in our cash capital expenditures was primarily the result of lower transmission segment capital expenditures, particularly at CL&P, due to the completion in 2008 of three major transmission projects in southwest Connecticut. We project total capital expenditures of approximately \$960 million in 2009 (including non-cash factors).

After rate reduction bond (RRB) payments included in financing activities, we had cash flows provided by operating activities in the first nine months of 2009 of \$577.9 million, which represented an increase of \$325.7 million from the first nine months of 2008. The improved cash flows were due primarily to the increase in operating results from higher transmission revenues at CL&P, as well as NU cost management efforts; a shift in accounts receivable and unbilled revenue balances of approximately \$159 million; a lower level of operating costs that will be recovered from customers in future periods ("regulatory underrecoveries") of approximately \$141 million; and the absence in 2009 of the litigation settlement payment of \$49.5 million made in March 2008. We project consolidated cash flows provided by operating activities of approximately \$700 million in 2009, after RRB payments of approximately \$244 million. Consolidated cash flows provided by operating activities after RRB

payments are expected to total approximately \$4 billion from 2010 through 2014, ranging from approximately \$700 million in 2010 to approximately \$1.1 billion in 2014.

Overview

Consolidated: We earned \$64.8 million, or \$0.37 per share, in the third quarter of 2009 and \$245.3 million, or \$1.43 per share, in the first nine months of 2009, compared with \$72.7 million, or \$0.47 per share, in the third quarter of 2008 and \$188.9 million, or \$1.21 per share, in the first nine months of 2008. The decrease in 2009 third quarter results was due primarily to greater income tax expense as a result of lower tax benefits (and a higher effective income tax rate) from reduced capital expenditures and the absence of a benefit from the resolution of routine federal and state tax matters in 2008, as well as higher expenses related to uncollectible receivable balances. The results for the first nine months of 2009 were also impacted by a higher effective income tax rate from lower tax benefits as a result of reduced capital expenditures. The EPS for 2009 also reflects the issuance of approximately 19 million common shares on March 20, 2009. The 2008 results include a first-quarter, after-tax charge of \$29.8 million, or \$0.19 per share, resulting from the settlement of litigation. A summary of our earnings by segment, which also reconciles the non-GAAP financial measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, to the most directly comparable GAAP measures of consolidated net income attributable to controlling interests and fully diluted EPS, for the third quarter and first nine months of 2009 and 2008 is as follows:

(Millions of Dollars, except per share amounts)	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2009		2008		2009		2008	
	Amount	Per Share	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net income attributable to controlling interests (GAAP)	\$ 64.8	\$ 0.37	\$ 72.7	\$ 0.47	\$ 245.3	\$ 1.43	\$ 188.9	\$ 1.21
Regulated companies	\$ 65.3	\$ 0.37	\$ 71.4	\$ 0.46	\$ 240.0	\$ 1.40	\$ 218.5	\$ 1.40
Competitive businesses	0.3	-	4.6	0.03	11.6	0.07	8.7	0.05
NU parent and other companies	(0.8)	-	(3.3)	(0.02)	(6.3)	(0.04)	(8.5)	(0.05)
Non-GAAP	64.8	0.37	72.7	0.47	245.3	1.43	218.7	1.40

earnings

Litigation

charge

(after-tax)

-	-	-	-	-	-	-	(29.8)	(0.19)
---	---	---	---	---	---	---	--------	--------

Net income

attributable to \$

controlling

interests

(GAAP)

64.8	\$	0.37	\$	72.7	\$	0.47	245.3	\$	1.43	\$	188.9	\$	1.21
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Regulated Companies: Our regulated companies operate in two segments: electric transmission and electric and gas distribution, with PSNH generation included in the distribution segment. A summary of regulated company earnings by segment for the third quarter and first nine months of 2009 and 2008 is as follows:

(Millions of Dollars)	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2009		2008		2009		2008	
CL&P Transmission	\$	33.7	\$	30.7	\$	98.9	\$	86.5
PSNH Transmission		5.5		3.6		14.1		12.4
WMECO Transmission		3.6		1.6		7.0		4.7
Total Transmission		42.8		35.9		120.0		103.6
CL&P Distribution		11.4		23.5		55.0		57.2
PSNH Distribution		10.7		10.7		36.2		32.3
WMECO Distribution		4.9		3.6		13.5		10.1
Yankee Gas		(4.5)		(2.3)		15.3		15.3
Total Distribution		22.5		35.5		120.0		114.9
Net Income - Regulated Companies	\$	65.3	\$	71.4	\$	240.0	\$	218.5

The higher third quarter and first nine months of 2009 transmission segment earnings reflect a higher level of investment in this segment as we continued to build out our transmission infrastructure to meet our customers' and the region's reliability needs. The results primarily reflect the effect of CL&P's investment of approximately \$1.6 billion since the beginning of 2005 in the southwest Connecticut transmission projects that were completed in late 2008. The first nine months of 2008 transmission segment results included earnings of approximately \$2.9 million related to the February 1, 2005 through December 31, 2007 time period as a result of a first quarter 2008 order issued by the Federal Energy Regulatory Commission (FERC).

CL&P's third quarter 2009 distribution segment earnings were \$12.1 million lower than the same period in 2008 due primarily to greater income tax related expense of approximately \$11 million primarily related to the absence of a benefit from the resolution of routine tax matters in 2008. Third quarter 2009 earnings were also lower as a result of certain higher operating costs, including expenses related to uncollectible receivable balances, pension, depreciation

and interest expense, partially offset by specific cost management efforts. Retail electric sales were 5 percent lower than 2008, but revenues were higher due primarily to the distribution rate increase that took effect on February 1, 2009. Third quarter 2009 earnings also benefited from the recognition of gains on securities in the NU supplemental benefit trust.

For the first nine months of 2009, CL&P's distribution segment earnings were \$2.2 million lower than the same period in 2008 due primarily to increased income tax expense from a higher effective tax rate and certain higher operating costs, partially offset by higher revenues and recognition of gains on securities in the NU supplemental benefit trust.

Certain operating costs were higher in 2009 including expenses related to uncollectible receivable balances, depreciation and amortization, and interest expense, partially offset by specific cost management efforts, and lower storm costs. CL&P's retail electric sales were 3.9 percent lower for the first nine months of 2009, but revenues were higher due primarily to distribution rate increases effective February 1, 2008 and February 1, 2009. For the 12 months ended September 30, 2009, CL&P's distribution segment Regulatory ROE was 7 percent, and for the full year 2009, we expect it to be approximately 7 percent.

PSNH's third quarter 2009 distribution segment earnings were the same as the third quarter of 2008. Positive factors in the third quarter of 2009 included higher revenues attributable to the temporary distribution rate increase effective August 1, 2009, higher generation-related earnings, recognition of gains on securities in the NU supplemental benefit trust, and lower interest expense. Offsetting these positive factors was a 3.8 percent decline in retail electric sales and higher expenses including income taxes, pension costs, expenses related to uncollectible receivable balances, depreciation, and property taxes.

PSNH's distribution segment earnings for the first nine months of 2009 were \$3.9 million higher than the same period of 2008 due primarily to higher generation-related earnings, lower carrying costs on credits owed to customers, recognition of gains on securities in the NU supplemental benefit trust, and higher revenues due to the August 1, 2009 distribution rate increase, partially offset by higher depreciation, property taxes, pension costs, expenses related to uncollectible receivable balances, and a 3.8 percent decrease in retail electric sales. For the 12 months ended September 30, 2009, PSNH's distribution segment Regulatory ROE was 7.4 percent (including generation), which reflects a Regulatory ROE for the distribution business of 3.9 percent. PSNH's generation segment has an authorized ROE of 9.8 percent. For the full year 2009, we expect PSNH's distribution segment Regulatory ROE to be approximately 7.5 percent.

WMECO's third quarter 2009 distribution segment earnings were \$1.3 million higher than the same period in 2008 due primarily to the absence of a \$1.4 million pre-tax charge for potential refunds to customers that was recorded in the third quarter of 2008, lower storm costs and employee benefit costs, and the recognition of gains on securities in the NU supplemental benefit trust, partially offset by higher property taxes, depreciation and amortization, and a 2.7 percent decrease in retail electric sales.

WMECO's distribution segment earnings for the first nine months of 2009 were \$3.4 million higher than the same period in 2008 due primarily to the absence of a \$1.6 million pre-tax charge related to a DPU ruling and a \$1.4 million pre-tax charge for potential refunds to customers, both of which were recorded in 2008, lower operating costs including storm costs, and lower employee benefit costs. Partially offsetting these positive factors were higher

property taxes, depreciation and amortization, and a 5.3 percent decrease in retail electric sales. For the 12 months ended September 30, 2009, WMECO's distribution segment Regulatory ROE was 8.6 percent, and for the full year 2009, we expect it to be approximately 8 percent.

Yankee Gas's third quarter 2009 loss was \$2.2 million greater than the same period in 2008 due primarily to higher expenses related to uncollectible receivable balances, employee benefit costs, and interest expense, partially offset by higher revenues attributable to a 5.8 percent increase in firm natural gas sales.

For the first nine months of 2009, Yankee Gas's earnings were the same as the first nine months of 2008. The 2008 earnings included a \$5.8 million pre-tax charge for refunds of previous gas cost recoveries. The 2009 earnings reflect certain higher operating costs, including expenses related to uncollectible receivable balances, employee benefits, and interest expense, partially offset by higher revenues as a result of an 8.2 percent increase in firm natural gas sales, and the resolution of tax matters. For the 12 months ended September 30, 2009, Yankee Gas's Regulatory ROE was 8 percent, and for the full year 2009, we expect it to be approximately 8 percent.

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric gigawatt-hour (GWh) sales and Yankee Gas firm natural gas sales for the third quarter and first nine months of 2009 as compared to the same periods in 2008 on an actual and weather normalized basis (using a 30-year average) is as follows:

For the Three Months Ended September 30, 2009 Compared to 2008

Electric

	CL&P		PSNH		WMECO		Total	
	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)
Residential	(2.4)%	3.6 %	(0.8)%	0.9 %	-	5.5 %	(1.8)%	3.0 %
Commercial	(4.0)%	(0.8)%	(3.9)%	(2.6)%	(2.1)%	1.0 %	(3.8)%	(1.8)%
Industrial	(17.7)%	(15.7)%	(9.7)%	(8.2)%	(9.3)%	(7.7)%	(14.3)%	(12.5)%
Other	2.4 %	2.4 %	(3.6)%	(3.6)%	(6.8)%	(6.8)%	1.4 %	1.4 %
Total	(5.0)%	(0.9)%	(3.8)%	(2.3)%	(2.7)%	1.0 %	(4.5)%	(2.3)%

For the Nine Months Ended September 30, 2009 Compared to 2008

Electric

	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)
Residential	(0.5)%	2.2 %	(0.7)%	0.4 %	(1.3)%	0.9 %	(0.6)%	0.9 %
Commercial	(3.3)%	(1.4)%	(3.8)%	(2.7)%	(5.2)%	(3.5)%	(3.6)%	(1.8)%
Industrial	(18.1)%	(16.8)%	(10.3)%	(9.0)%	(13.5)%	(12.5)%	(15.2)%	(13.5)%
Other	(1.2)%	(1.2)%	(3.5)%	(3.5)%	8.0 %	8.0 %	(0.7)%	(0.7)%
Total	(3.9)%	(1.8)%	(3.8)%	(2.7)%	(5.3)%	(3.5)%	(4.0)%	(2.3)%

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 the third quarter and first nine months of 2009 and 2008 is as follows:

For the Three Months Ended September 30,

	Electric			Firm Natural Gas		
	2009	2008	Percentage Increase/ (Decrease)	2009	2008	Percentage Increase
Residential	3,768	3,837	(1.8)%	1,107	1,024	8.1%
Commercial	3,828	3,978	(3.8)%	1,341	1,313	2.2%
Industrial	1,190	1,389	(14.3)%	3,038	2,849	6.6%
Other	80	79	1.4 %	-	-	-
Total*	8,866	9,282	(4.5)%	5,486	5,185	5.8%

For the Nine Months Ended September 30,

	Electric			Firm Natural Gas		
	2009	2008	Percentage Decrease	2009	2008	Percentage Increase
Residential	10,883	10,947	(0.6)%	9,263	8,930	3.7%
Commercial	10,930	11,335	(3.6)%	9,708	8,890	9.2%
Industrial	3,318	3,914	(15.2)%	10,791	9,684	11.4%
Other	244	246	(0.7)%	-	-	-
Total*	25,376	26,442	(4.0)%	29,762	27,504	8.2%

*Amounts may not total due to rounding of GWh or million cubic feet.

Similar to second quarter of 2009, our third quarter 2009 actual retail electric sales were significantly impacted by the weather and economic conditions and were lower than the same period in 2008. The negative trend in our sales continues to be most prevalent in the industrial class where many customers have been negatively impacted by the economic conditions of our region and nation. We believe the reduction in industrial sales is primarily driven by a reduced number of shifts and days of operations.

Our residential sales in the third quarter of 2009 for CL&P and PSNH were lower than in the third quarter of 2008, and WMECO's residential sales in the third quarter of 2009 were unchanged from the third quarter of 2008. On a weather normalized basis, residential sales in the third quarter of 2009 for all three electric distribution companies were higher than the same period in 2008. The significant difference between actual and weather normalized residential sales in the third quarter of 2009 reflects the fact that the amount of cooling degree days for this time period was approximately 20 percent and 12 percent lower than the same period last year for Connecticut/Western Massachusetts and New Hampshire, respectively. The cool and rainy weather in June 2009 continued through much of the third quarter and decreased the amount of air conditioning load. For the first nine months of 2009, residential

sales for all three electric distribution companies were lower than the same period in 2008, but on a weather normalized basis, residential sales were higher than they were in 2008.

Recovery of our distribution revenues, however, varies between customer classes. As compared to other customer classes, a greater portion of residential revenues is recovered through volumetric charges. In contrast to residential rates, a much smaller portion of commercial and industrial revenues is recovered through volumetric charges.

Distribution rates for certain large businesses are structured so that we recover 100 percent of the distribution revenues through non-volumetric charges. In this regard, rate design has significantly mitigated the impact of the declining commercial and industrial sales on distribution revenues and earnings.

Actual and weather normalized firm natural gas sales in the third quarter of 2009 and for the first nine months of 2009 were higher than the same periods in 2008. The 2009 results for the commercial and industrial sectors have benefitted substantially from the addition of new large gas-fired distributed generation in Yankee Gas's service region during the last twelve to fifteen months. Yankee Gas recovers almost half of its total distribution revenues through non-usage charges, and thus, similar to our electric distribution companies, changes in sales have less of an impact on revenues.

Our expense related to uncollectible receivable balances (or uncollectibles expense) is influenced by the economic conditions of our region. The weak economic conditions in the Northeast continue to have a negative effect on our customers. For the third quarter of 2009, our total uncollectibles expense was approximately \$12.8 million higher than the same period in 2008. For the first nine months of 2009, our total uncollectibles expense was approximately \$23.6 million higher than the same period in 2008. These increases in our 2009 uncollectibles expense were partially mitigated from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated 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 (or hardship customers) are fully recovered through their respective tariffs. Of the \$12.8 million and \$23.6 million increase in uncollectibles expense for the third quarter and first nine months of 2009, approximately \$7.2 million and \$10.2 million, respectively, was not recovered and impacted earnings.

Competitive Businesses: NU Enterprises, which continues to manage to completion Select Energy Inc.'s (Select Energy) remaining wholesale marketing contracts and to manage its energy services activities, earned \$0.3 million in the third quarter of 2009 and \$11.6 million in the first nine months of 2009, compared with earnings of \$4.6 million in the third quarter of 2008 and \$8.7 million in the first nine months of 2008. Competitive business earnings for the third quarter of 2009 included an after-tax mark-to-market loss of \$0.9 million associated with Select Energy's wholesale marketing contracts, as compared to an after-tax mark-to-market gain of \$3.6 million in the third quarter of 2008.

Earnings for the first nine months of 2009 and 2008 included after-tax mark-to-market gains of \$3.7 million and \$2.7 million, respectively. Results for the first nine months of 2008 included a net after-tax charge of \$2.8 million associated with the implementation of accounting guidance for fair value measurements. Results for NU Enterprises are not expected to continue at the 2008 and 2009 earnings levels. The margins Select Energy earns on its remaining

contracts are expected to decline in future years.

NU Parent and Other Companies: NU parent and other companies recorded net expenses of \$0.8 million in the third quarter of 2009 and \$6.3 million in the first nine months of 2009, compared with net expenses of \$3.3 million in the third quarter of 2008 and \$38.3 million in the first nine months of 2008. The net expenses in the first nine months of 2008 included a \$29.8 million after-tax charge resulting from the payment of \$49.5 million made in March 2008 associated with a litigation settlement. The decrease in net expenses for the third quarter of 2009 was the result of a decrease in net interest costs for NU parent due primarily to lower interest expense related to an interest rate swap on its fixed rate long-term debt, as well as interest earned on significantly higher cash balances after the sale of common shares in March 2009, which resulted in net proceeds of \$370.8 million.

Future Outlook

EPS Guidance: We continue to project consolidated 2009 earnings of between \$1.80 per share and \$1.90 per share.

A summary of our projected 2009 and 2010 EPS by segment, which also reconciles consolidated fully diluted EPS to the non-GAAP financial measures of EPS by segment, is as follows:

(Approximate amounts)	2009 EPS Range		2010 EPS Range	
	Low	High	Low	High
Fully Diluted EPS (GAAP)	\$ 1.80	\$ 1.90	\$ 1.80	\$ 2.00
Regulated companies:				
Distribution segment	\$ 0.90	\$ 1.00	\$ 0.95	\$ 1.05
Transmission segment	0.90	0.90	0.90	0.95
Total regulated companies	1.80	1.90	1.85	2.00
Competitive businesses	0.05	0.05	0.00	0.05
NU parent and other companies	(0.05)	(0.05)	(0.05)	(0.05)
Fully Diluted EPS (GAAP)	\$ 1.80	\$ 1.90	\$ 1.80	\$ 2.00

We have included estimated impacts from current economic conditions in the assumptions that were used to develop our earnings guidance. The 2010 distribution segment guidance reflects a one percent annual decrease in total retail electric sales, as well as uncertainty around the outcomes of the PSNH distribution rate case that was filed in mid-2009 and a CL&P distribution rate case that we expect to file in late 2009 or early 2010. A Yankee Gas rate case is also being considered but additional earnings from such a filing are not included in the above projections. Both the PSNH and CL&P rate case decisions are expected around mid-2010.

Long-Term Growth Rate: We project that we will achieve a compound average annual EPS growth rate for the five-year period of 2010 to 2014 of between 6 percent and 9 percent, using 2009 projected EPS of between \$1.80 and \$1.90 as the base level. This EPS growth rate assumes Regulatory ROEs of approximately 12.25 percent for the transmission segment and an average of approximately 10 percent for the distribution segment (including generation).

We believe this growth will be achieved if our capital program is completed in accordance with our plans, distribution rate case orders enable us to earn fair Regulatory ROEs and FERC's current transmission policies remain consistent and enable us to achieve projected transmission ROEs. In addition to the assumptions above, there are certain items that will likely impact this earnings growth rate. These items include, but are not limited to, sales levels; operating expense levels, including maintenance, pension and uncollectibles expense; and lower margins that NU Enterprises expects to earn on its remaining contracts.

Liquidity

Consolidated: We had \$249 million of cash and cash equivalents on hand as of September 30, 2009, compared with \$89.8 million as of December 31, 2008. During the first nine months of 2009 our cash position increased primarily as a result of the issuance of 18,975,000 common shares by NU on March 20, 2009, which yielded gross proceeds of approximately \$380 million, and the issuance of \$250 million of first mortgage bonds by CL&P on February 13, 2009.

On October 5, 2009, the NHPUC approved an application by PSNH to issue \$150 million of first mortgage bonds and increase its short-term debt limit to \$60 million above the statutory limit of 10 percent of net plant, which represents approximately \$157 million. A request for rehearing on the NHPUC's decision has been filed, however, we currently expect PSNH to issue the bonds by the end of 2009. No other long-term debt or equity financings are planned by NU parent or its subsidiaries in 2009. Our planned financings for 2010 total approximately \$340 million of new long-term debt comprised of \$170 million at PSNH, \$90 million at WMECO and \$80 million at Yankee Gas. We have only annual sinking fund requirements of \$4.3 million continuing in 2010 through 2012, the mandatory tender of \$62 million of tax-exempt Pollution Control Revenue Bonds (PCRBs) by CL&P in 2010, which CL&P expects will be remarketed in the ordinary course, and no debt maturities until April 1, 2012.

The proceeds from our 2009 and 2010 financings were or will be used primarily to repay short-term borrowings and fund our capital programs. The combined borrowings and letters of credit (LOCs) outstanding on our revolving credit facilities totaled \$397.2 million as of September 30, 2009, compared with approximately \$706 million as of December 31, 2008.

We had cash flows provided by operating activities, after RRB payments included in financing activities, in the first nine months of 2009 of \$577.9 million, compared with \$252.2 million in the first nine months of 2008. The improved cash flows were due primarily to the increase in operating results from higher transmission revenues at CL&P after significant projects were placed in service in late 2008 as well as NU cost management efforts; a shift in accounts receivable and unbilled revenue balances of approximately \$159 million; a decrease in regulatory underrecoveries of approximately \$141 million related primarily to CL&P's Federally Mandated Congestion Charge (FMCC), Generation Service Charge (GSC), and reserve for Conservation and Load Management (C&LM)

included in customer rates; a favorable change in fuel, materials and supplies balances of approximately \$78 million due primarily to the lower cost of 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 March 2008. These favorable factors were partially offset by a negative shift in timing of cash disbursements from accounts payable of approximately \$184 million.

We project consolidated cash flows provided by operating activities of approximately \$700 million in 2009, after RRB payments of approximately \$244 million. Consolidated cash flows provided by operating activities after RRB payments are expected to total approximately \$4 billion from 2010 through 2014, ranging from approximately \$700 million in 2010, after RRB payments of approximately \$260 million, to approximately \$1.1 billion in 2014, assuming our capital projects are completed as expected and we receive fair regulatory treatment on related expenditures. We expect the vast majority of our capital program to be funded through cash flows provided by operating activities and new debt issuances, and currently anticipate a single NU common equity issuance in the next five years of approximately \$300 million, which is expected no earlier than 2012.

A summary of the current credit ratings and outlooks by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (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-	Stable	BBB	Stable
CL&P	A2	Stable	BBB+	Stable	A-	Stable
PSNH	A3	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

On October 9, 2009, Fitch concluded its annual review of NU parent and its electric utilities by reaffirming all of its existing credit ratings and stable outlooks. On October 27, 2009, Moody's published credit opinions on CL&P and WMECO in which it reaffirmed the companies' ratings and stable outlooks.

If NU parent's senior unsecured debt ratings 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 September 30, 2009, Select Energy, under its remaining contracts, would have been required to provide additional cash or LOCs in an aggregate amount of \$29.1 million to various unaffiliated counterparties and additional cash or LOCs in the aggregate amount of \$2 million to an independent system operator. NU parent would have been and remains able to provide that collateral on behalf of

Select Energy.

If unsecured debt ratings for CL&P or PSNH were to be reduced by either Moody's or S&P, certain supply contracts could require CL&P and PSNH to post additional collateral in the form of cash or LOCs with various unaffiliated counterparties. As of September 30, 2009, CL&P only had one supply contract requiring collateral posting for which \$1 million of cash collateral has been posted for the out-of-the-money position. No additional collateral would have been required of CL&P under its supply contracts if its unsecured debt ratings had been reduced. If PSNH's unsecured debt ratings had been reduced by one level, PSNH would have been required to post additional collateral of \$1.8 million as of September 30, 2009. If these ratings had been reduced by two levels or below investment grade, the amount of additional collateral required to be posted by PSNH would have been \$14.8 million as of September 30, 2009. PSNH would have been and remains able to provide these collateral amounts.

On July 1, 2009, WMECO filed an application with the DPU to issue and sell up to \$150 million of senior secured or unsecured long-term debt. If WMECO decides to issue first mortgage bonds, WMECO will be obligated to secure its \$195 million of currently outstanding senior unsecured notes equally and ratably with such first mortgage bonds.

We paid common dividends of \$120.6 million in the first nine months of 2009, compared with \$95.8 million in the first nine months of 2008. The increase is the result of a 6.3 percent increase in our common dividend rate that took effect in the third quarter of 2008, an additional 11.8 percent increase that took effect in the first quarter of 2009, and a higher number of shares outstanding in the second and third quarters of 2009. On October 13, 2009, our Board of Trustees declared a common dividend of \$0.2375 per share, payable on December 31, 2009 to shareholders of record as of December 1, 2009.

We target paying out approximately 50 percent of consolidated earnings in the form of common dividends. 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 certain state statutes, the leverage restrictions in our revolving credit agreement and the ability of our subsidiaries to pay common dividends. 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, and 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.

In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In the first nine months of 2009, CL&P, PSNH, WMECO, and Yankee Gas paid \$85.4 million, \$30.6 million, \$14.7 million, and \$19.1 million, respectively, in common dividends to NU parent. In the first nine months of 2009, NU parent made cash equity contributions of \$116.6 million and \$68.9 million to CL&P and PSNH, respectively. NU parent made minimal cash equity contributions to WMECO and Yankee Gas for the nine months ended September 30, 2009.

Cash capital expenditures included on the accompanying unaudited condensed consolidated statements of cash flows and described in the Liquidity section of this Management's Discussion and Analysis do not include amounts incurred on capital projects but not yet paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portions of pension and postretirement benefits other than pension (PBOP) expense or income. A summary of our cash capital expenditures by company for the first nine months of 2009 and 2008 is as follows:

For the Nine Months Ended September 30,			
(Millions of Dollars)	2009		2008
CL&P	\$ 331.6	\$	678.6
PSNH	169.4		164.8
WMECO	63.7		49.6
Yankee Gas	39.1		39.1
Other	30.6		19.7
Totals	\$ 634.4	\$	951.8

The decrease in our total cash capital expenditures was primarily the result of lower transmission segment capital expenditures, particularly at CL&P (refer to "Business Development and Capital Expenditures" for further discussion).

As a result of Lehman Brothers Commercial Bank (LBCB) declining to fund its commitment of approximately \$56 million under our credit facilities in 2008 as referred to below, our aggregate borrowing capacity under our credit facilities was reduced from \$900 million to \$844 million. We believe this borrowing capacity, when combined with our access to other funding sources, provides operating flexibility to maintain adequate liquidity.

NU parent has a credit facility in a nominal aggregate amount of \$500 million, \$482.3 million excluding the commitment of LBCB, which expires on November 6, 2010. As of September 30, 2009, NU parent had \$72 million

of LOCs issued for the benefit of certain subsidiaries (primarily PSNH) and \$146.6 million of borrowings outstanding under this facility. The weighted-average interest rate on these short-term borrowings as of September 30, 2009 was 0.625 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings. NU parent had approximately \$263.7 million of borrowing availability on this facility as of September 30, 2009, excluding LBCB's commitment, as compared to \$101.3 million of availability as of December 31, 2008.

The regulated companies maintain a joint credit facility in a nominal aggregate amount of \$400 million, \$361.8 million excluding the commitment of LBCB, which also expires on November 6, 2010. There were \$178.6 million of borrowings outstanding under this facility as of September 30, 2009 (\$33 million for CL&P, \$45.2 million for PSNH, \$75.1 million for WMECO, and \$25.3 million for Yankee Gas). The weighted-average interest rate on these short-term borrowings as of September 30, 2009 was 0.64 percent, which is based on a variable rate plus an applicable margin based on the borrower's credit ratings. The regulated companies had approximately \$183.2 million of aggregate borrowing availability on this facility as of September 30, 2009, excluding LBCB's commitment and subject to each individual company's borrowing limits, as compared to \$56.5 million of availability as of December 31, 2008.

Our credit facilities and bond 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 capitalization ratio. All such companies currently are, and expect to, remain in compliance with these covenants. Refer to Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to our consolidated financial statements included in the 2008 Form 10-K for further discussion of material terms and conditions of these agreements.

Impact of Financial Market Conditions: While the impact of continued market volatility and the extent and impacts of the current economic downturn cannot be predicted, we believe that we currently have operating flexibility and access to funding sources to maintain adequate liquidity. The credit outlooks for NU parent and its regulated companies are all stable. Our companies have low risk of calls for collateral due to our business model, as described further below, and we have no long-term debt maturing until April 2012. An estimated cash contribution to our pension plan of \$50 million is expected to be made in the third quarter of 2010, as further described below, and we project capital expenditures for 2010 of approximately \$1.1 billion. However, we project cash flows provided by operating activities for 2010 of approximately \$700 million, and, based on our successful financings in 2009, we do not anticipate any difficulty in accessing the capital markets in 2010 for our total planned debt issuances of approximately \$340 million.

Our regulated standard offer type contracts do not require us to post collateral. In the event of an energy supplier's default under these contracts we could be required to provide standard offer type services directly to customers until a substitute supplier could be arranged. Such an event would require us to post additional collateral with the New England Independent System Operator (ISO-NE). Our suppliers currently are performing on these contracts, and any additional costs we would incur from a supplier default would be recoverable from customers. In other regulated contracts that do contain collateral posting requirements, the counterparties are generally exposed to us at this time, and when we have been exposed to them, these counterparties have been posting the necessary collateral. As of September 30, 2009 and December 31, 2008, PSNH had posted \$56 million and \$75 million, respectively, in related collateral in the form of NU parent LOCs with counterparties. PSNH had an additional \$10 million of LOCs posted with ISO-NE at September 30, 2009 and December 31, 2008. Also, the ongoing collateral requirements for Select Energy's few remaining wholesale contracts are not material as it continues to wind down this business. Select Energy has not experienced any significant performance difficulties with suppliers on its remaining sourcing contracts. As of September 30, 2009, Select Energy had posted \$30.2 million in collateral due to the exposure of counterparties to us, including collateral posted with counterparties under master netting agreements, as compared to \$26.3 million as of December 31, 2008. Refer to "NU Enterprises Contracts - Counterparty Credit" in this Management's Discussion and Analysis for further discussion.

As of January 1, 2008 our pension plan funded ratio (the value of plan assets divided by the funding target in accordance with the requirement of the Pension Protection Act or PPA) was 111 percent. We have not been required to make a contribution to the plan since 1991. As of January 1, 2009, due primarily to the negative financial market conditions experienced in 2008, the fair value of our pension plan assets dropped by approximately \$900 million to \$1.56 billion. On October 7, 2009, the Internal Revenue Service issued final regulations on the PPA funding rules, which allows us to maximize our funding flexibility by using the October 2008 yield curve rate for the January 1, 2009 valuation of pension plan liabilities. Using the October 2008 yield curve rate, our pension plan funded ratio was 100 percent as of January 1, 2009. We currently estimate that a contribution of approximately \$50 million will be made in the third quarter of 2010 for the purpose of satisfying benefit obligations accrued during 2009, and that contributions totaling approximately \$200 to \$250 million will be made in 2011. PSNH is currently expected to fund approximately \$30 million and \$157 million of the 2010 and 2011 contributions, respectively. The actual amount of future contributions will depend on many factors, including the performance of existing plan assets, valuation of the plan's liabilities, and long-term discount rates.

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 \$650.6 million in the first nine months of 2009, compared with \$946.6 million in the first nine months of 2008. These amounts included \$34.4 million and \$14.7 million in the first nine months of 2009 and 2008, respectively, that related to our corporate service companies that support the regulated companies.

Regulated Companies: Capital expenditures for the regulated companies are expected to total approximately \$960 million (\$429 million for CL&P) in 2009, which includes planned spending of approximately \$52 million for our corporate service companies that support the regulated companies.

Transmission Segment: Transmission segment capital expenditures decreased by \$375.5 million in the first nine months of 2009, as compared with the same period in 2008, due primarily to reduced expenditures at CL&P, which completed three major transmission projects in southwest Connecticut in the second half of 2008. Capital expenditures for the consolidated transmission segment are expected to total approximately \$275 million (\$148 million for CL&P) in 2009. A summary of transmission segment capital expenditures by company in the first nine months of 2009 and 2008 is as follows:

		For the Nine Months Ended September 30,	
(Millions of Dollars)		2009	2008
CL&P	\$	112.9	\$ 486.4
PSNH		41.8	58.6
WMECO		44.3	27.9
HWP		-	1.6 *
Totals	\$	199.0	\$ 574.5

*

Represents capital additions of Holyoke Water Power Company (HWP), which were transferred to WMECO in December 2008.

In October 2008, we commenced state siting filings for our current series of major transmission projects, New England East-West Solutions (NEEWS). That series of projects involves our construction of new overhead 345 kilovolt (KV) lines in Massachusetts and Connecticut as well as associated substation work and 115 KV rebuilds.

One of the projects will connect to a new transmission line that National Grid USA plans to build in Rhode Island and Massachusetts. On September 24, 2008, ISO-NE issued its technical approval of the NEEWS projects, which was a precursor to the siting application process. We estimate that CL&P's and WMECO's

total capital expenditures for these projects will be \$1.49 billion through 2014. ISO-NE is currently performing an evaluation of all projects in its regional system plan, including NEEWS, and assessing the presently estimated need dates for these projects. The timing and amount of our projected annual capital spending could be affected if receipt of siting approvals is delayed or if the need dates for these projects change through ISO-NE's regional system planning process. Since inception of the project through September 30, 2009, CL&P and WMECO have capitalized approximately \$56.6 million and \$58.8 million, respectively, in costs associated with NEEWS, of which \$23.3 million and \$24.4 million, respectively, were capitalized in the first nine months of 2009.

The first of the NEEWS projects, Greater Springfield Reliability Project (GSRP), which involves the construction of a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. ISO-NE has reaffirmed the need and need date for GSRP. This project is expected to cost approximately \$714 million if built according to our preferred route configuration. CL&P filed its application to build the Connecticut portion of the GSRP with the Connecticut Siting Council (CSC) on October 20, 2008. WMECO filed its application to build its portion of the project with the Massachusetts Energy Facilities Siting Board (MAEFSB) on October 27, 2008. Public hearings before the MAEFSB and CSC began in May 2009 and September 2009, respectively. Evidentiary hearings before the CSC began in July 2009 and are expected to conclude in the fourth quarter of 2009. A joint hearing between the CSC and MAEFSB on topics common to both states' proceedings was held in September 2009. Evidentiary hearings before the MAEFSB commenced on November 2, 2009 and are expected to be completed in the fourth quarter of 2009. The CSC is considering other applications in parallel with the GSRP application to ascertain which projects satisfy the reliability needs identified by ISO-NE. Following decisions by the state siting boards, which are expected by early to mid-2010, we expect to commence construction in mid- to late 2010 and to place the project in service in 2013.

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 line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid USA is designing. We estimate CL&P's share of the costs of this project will be approximately \$250 million. Municipal consultations concluded in November 2008, and CL&P plans to file its siting application with Connecticut regulators in mid-2010, following the completion by ISO-NE of its evaluation of the need date for this project as part of its regional system planning process expected by the end of 2009 or in early 2010. We currently expect the project to be placed in service in late 2013.

The third 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 connection to move power across the state of Connecticut. The timing of this project would be six to twelve months behind the Interstate Reliability Project, and CL&P currently expects to file the siting application in late 2010. ISO-NE continues to evaluate the need date for this project as part of its regional system planning process, with expected completion by the end of 2009 or in early 2010. This project is currently expected to be placed in service in mid- to late 2014 after the other two projects, at an estimated cost of approximately \$315 million. Included as part of NEEWS are approximately \$211 million of associated reliability related expenditures, some of which may be incurred in advance of the three major projects.

During the siting approval process, state regulators may require changes in configuration (including placing some lines underground) to address local concerns that could increase construction costs. Our current design for NEEWS does not contemplate any underground lines. Building any lines underground, particularly 345 KV lines, would increase total costs of the project beyond those reflected above.

NU, NSTAR, and Hydro-Québec (HQ), a large Canadian utility, are engaged in planning a 1,200 MW high voltage direct current (HVDC) transmission line from Canada to New Hampshire to deliver and sell low carbon energy in New England. FERC granted conceptual approval of the project in May 2009 and we expect to file a Transmission Service Agreement (TSA) in late 2009 or early 2010. In July 2009, FERC granted rehearing on two third-party requests but has not indicated when an order on rehearing will be issued.

Critical components of the HQ project include the location of the southern terminus of the new line, the negotiation of power purchase agreements (PPAs) between H.Q. Energy Services (U.S.) Inc. (HQUS), New England utilities and other entities for terms that are expected to be at least 20 years, and the TSA. Final determination of the location of the southern HVDC terminus is viewed by both NU/NSTAR and HQUS as a critical path decision, and final studies are being completed to make that determination. We anticipate that the PPAs can be successfully negotiated with HQUS and NSTAR and filed with respective state commissions in 2010. Among other permits and approvals, this transmission project would require state and federal siting approvals and technical approval from ISO-NE as appropriate. We believe that the approval process will be initiated in 2010, with construction to commence upon receipt of all necessary permits, at an estimated cost to NU of \$675 million, and transmission of power over the new line could commence in late 2014 to early 2015.

Distribution Segment: Distribution segment capital expenditures increased by \$59.8 million in the first nine months of 2009, as compared with the same period in 2008, primarily due to increased generation business capital expenditures at PSNH related to its Clean Air Project further described below and the absence in 2009 of a \$17.5 million capital cost recovery by Yankee Gas related to a legal settlement in February 2008. We currently expect capital expenditures for the consolidated distribution segment to total approximately \$633 million in 2009 (\$281 million for CL&P and \$147 million for the PSNH generation business).

A summary of distribution segment capital expenditures by company in the first nine months of 2009 and 2008 is as follows:

(Millions of Dollars)	For the Nine Months Ended September 30,			
	2009		2008	
CL&P	\$	203.8	\$	202.4
PSNH		65.4		65.3
WMECO		24.6		24.9
Totals - Electric distribution (excluding generation)		293.8		292.6
Yankee Gas		39.2		24.9
Other		0.3		0.4
Total distribution		333.3		317.9
PSNH generation		83.9		39.5
Total distribution segment	\$	417.2	\$	357.4

PSNH's Clean Air Project is currently expected to cost \$457 million, which will be recovered through PSNH's generation rates under New Hampshire law. Construction is ahead of schedule and on budget, and PSNH currently expects to complete the project by mid-2012. Since inception of the project, PSNH has capitalized approximately \$98.6 million associated with this project, of which \$71.1 million was capitalized in the first nine months of 2009. We expect this project to be approximately 33 percent complete by the end of 2009.

Smart Grid and Other Strategic Initiatives: We continue to evaluate certain development projects that would benefit our customers, such as investments in AMI systems and other projects that are detailed below:

On August 6, 2009, CL&P, PSNH and WMECO filed an application with the DOE for federal stimulus funding for 50 percent of our approximate \$253 million investment in a project involving, among other things, the installation of smart grid technology in Connecticut, New Hampshire and Massachusetts, as well as expanded access to AMI

systems for over 200,000 of their customers. The DOE elected not to approve this application in October 2009. We continue to proceed with the smart meter initiatives at CL&P and WMECO further described below.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the AG concerning WMECO's proposal, under the Massachusetts Green Communities Act of 2007 (GCA), to install 6 MW of solar energy generation in its service territory at an estimated cost of \$41 million. Under the agreement, no more than 3 MW will be commissioned in any one year between 2010 and 2012, the ROE on these assets will be 9 percent, and the benefits of renewable energy and tax credits will be used to reduce the impact on customer bills. WMECO will need to file an additional application with the DPU if it seeks to develop more than the initial 6 MW under the GCA, which allows for electric utility ownership of up to 50 MW of solar energy generating facilities.

On August 31, 2009, CL&P completed a three-month dynamic pricing smart meter pilot program that involved nearly 3,000 customers. The pilot tested nearly 1,500 residential and 1,500 commercial and industrial customers' interest in and response to dynamic pricing rates, coupled with smart meters. CL&P is required to file a report on the results of the pilot with the DPUC on December 1, 2009. The cost of this pilot program is expected to be approximately \$13 million and is being recovered through CL&P rates. In the first quarter of 2010, CL&P expects to file an AMI deployment recommendation with the DPUC.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. The program proposes to involve 1,750 customers in WMECO's service region for a term of six months beginning in April 2011. The total cost of the project is projected to be \$7 million, which would be recovered through WMECO rates. A decision is expected from the DPU in the first half of 2010.

The estimated capital expenditures discussed below include expenditures for the WMECO solar program.

Projected Capital Expenditures and Rate Base Estimates: A summary of the projected capital expenditures for the regulated companies' transmission segment and the distribution and generation segment by company for 2009 and 2010 through 2014, including our corporate service companies' capital expenditures on behalf of regulated companies, is as follows:

(Millions of Dollars)	Year						2010-2014 Totals
	2009	2010	2011	2012	2013	2014	
CL&P transmission	\$ 148	\$ 136	\$ 203	\$ 281	\$ 286	\$ 155	\$ 1,061
PSNH transmission	58	55	118	107	74	22	376
WMECO transmission	67	66	256	328	156	6	812
HQ tie line	2	16	49	90	236	282	673
Total transmission	275	273	626	806	752	465	2,922
CL&P distribution	281	305	313	306	305	317	1,546
PSNH distribution	106	113	111	115	121	134	594
WMECO distribution	38	33	39	36	35	36	179
Total electric distribution	425	451	463	457	461	487	2,319
PSNH generation	147	187	117	82	68	26	480
WMECO generation	-	20	14	7	-	-	41
Total generation	147	207	131	89	68	26	521
Yankee Gas distribution	61	112	104	80	82	83	461
Corporate service companies	52	48	25	22	25	14	134
Totals	\$ 960	\$ 1,091	\$ 1,349	\$ 1,454	\$ 1,388	\$ 1,075	\$ 6,357

Actual capital expenditures could vary from the projected amounts for the companies and periods above. The continuation of weak economic conditions in the Northeast could impact the timing of our major transmission projects. Most of these capital investment projections, including those for the HQ tie line, assume timely regulatory approval, which in some cases requires extensive review. Delays in or denials of those approvals could reduce the levels of expenditures, associated rate base, and anticipated EPS growth. The capital program for 2010 through 2014 represents a decrease of approximately \$600 million, primarily in the PSNH transmission segment, from our previously announced capital program for 2009 through 2013. This decrease is due primarily to the completion of the remainder of our southwest Connecticut projects a year ahead of schedule and the reduction in costs of two projects in New Hampshire, which involved an upgrade in the east to west flow of power in southern New Hampshire and a new renewable transmission line in northern New Hampshire. The capital expenditures for these projects were reduced as a result of lower peak demand projections, short-term and lower cost solutions to address current reliability concerns, and the elimination from the ISO-NE generation capacity queue of 150 MW of wind generation in northern New

Hampshire.

Based on the above estimated expenditures, projected transmission, distribution, and generation rate base at December 31 of each year are as follows:

(Millions of Dollars)	Year					
	2009	2010	2011	2012	2013	2014
CL&P transmission	\$ 2,125	\$ 2,105	\$ 2,134	\$ 2,318	\$ 2,545	\$ 2,563
PSNH transmission	318	335	433	530	608	584
WMECO transmission	191	240	429	665	889	851
HQ tie line	-	-	-	-	-	675
Total transmission	2,634	2,680	2,996	3,513	4,042	4,673
CL&P distribution	2,179	2,333	2,497	2,629	2,778	2,911
PSNH distribution	764	849	941	1,030	1,090	1,156
WMECO distribution	394	413	434	447	456	461
Total electric distribution	3,337	3,595	3,872	4,106	4,324	4,528
PSNH generation	381	404	414	848	874	857
WMECO generation	-	-	29	31	28	25
Total generation	381	404	443	879	902	882
Yankee Gas distribution	717	764	843	892	932	974
Totals	\$ 7,069	\$ 7,443	\$ 8,154	\$ 9,390	\$ 10,200	\$ 11,057

Transmission Rate Matters

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 September 30, 2009, NU was in a total underrecovery position of \$12.2 million (\$7.5 million for CL&P).

Legislative Matters

2009 Federal Legislation: On February 17, 2009, President Obama signed into law The American Recovery and Reinvestment Act of 2009. We are benefiting from the Act's extension of tax rules allowing the accelerated deduction of depreciation, which we project will positively impact cash flow by approximately \$80 million in 2009. We also expect to benefit from the Act's solar credit provisions. We are continuing to evaluate further opportunities but cannot estimate at this time the ultimate impact that the Act will have on our earnings.

It is possible that the United States Environmental Protection Agency will adopt regulations and/or Congress will enact legislation addressing climate change and carbon constraints. Any such regulations or laws will likely impact PSNH's generating plants and possibly the prices that CL&P and WMECO pay for generation service. Until regulations are adopted or legislation is enacted, we are unable to determine the actual impacts on any of our companies. We would anticipate recovering related costs from customers.

Regulatory Developments and Rate Matters

Connecticut - CL&P:

Distribution Rates: CL&P implemented new distribution rates in 2009 to reflect the DPUC's 2008 decision allowing a \$20.1 million annualized increase in distribution rates, effective February 1, 2009. CL&P expects to file a new distribution rate case in either late 2009 or early 2010.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under Last Resort Service (LRS) rates. Effective July 1, 2009, the DPUC approved total average SS rates that did not change from the previous rates, though the energy supply portion of the rates increased from 12.316 cents per kilowatt-hour (kWh) to 12.516 cents per kWh. The DPUC also approved a decrease to CL&P's total average LRS rates of approximately 2.3 percent, which was primarily the result of the energy supply portion decreasing to 7.944 cents per kWh. Effective October 1, 2009, the DPUC approved an increase to CL&P's total average LRS rates of approximately 5.8 percent, which was primarily the result of the energy supply portion increasing to 8.657 cents per kWh. CL&P is fully recovering from customers the costs of its SS and LRS services.

CTA and SBC Reconciliation: On March 31, 2009, CL&P filed with the DPUC its 2008 Competitive Transition Assessment (CTA) and Systems Benefit Charge (SBC) reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2008, total CTA revenues exceeded CTA revenue requirements by \$84.9 million, which was recorded as a decrease to Regulatory assets. For the 12 months ended December 31, 2008, the SBC revenues exceeded SBC cost of service by \$2.5 million, which was recorded as a decrease to Regulatory assets. On September 30, 2009, the DPUC issued a final decision in this docket that approved the 2008 CTA and SBC reconciliations as filed. The final decision also stated that the DPUC will review the CTA and SBC Regulatory asset or liability balances later in 2009 to determine if rate changes are warranted effective January 1, 2010.

FMCC Filing: On February 6, 2009, CL&P filed with the DPUC its semi-annual FMCC filing, which reconciled actual FMCC revenues and charges and GSC revenues and expenses, for the period July 1, 2008 through December 31, 2008, and also included the previously filed revenues and expenses for the January 1, 2008 through June 30, 2008 period. The filing identified an underrecovery for the full year totaling approximately \$31.9 million. On November 5, 2009, the DPUC issued a draft decision accepting CL&P's calculations as filed. A final decision is expected in the fourth quarter of 2009. On August 3, 2009, CL&P filed with the DPUC its semi-annual FMCC filing for the period January 1, 2009 through June 30, 2009, which identified a net underrecovery of \$7.1 million for that period. A final decision is also expected in the fourth quarter of 2009. Both underrecoveries have been recorded as Regulatory assets on the accompanying unaudited condensed consolidated balance sheets. We do not expect the outcome of the DPUC's review of these filings to have a material adverse impact on CL&P's earnings, financial position or cash flows.

2008 Management Audit: An audit by a consulting firm hired by the DPUC, which is required to be conducted every six years by statute and requires a diagnostic review of all functions of CL&P, has been completed and a final report was received by CL&P on September 1, 2009. The outcome of this audit did not have an impact on CL&P's earnings, financial position or cash flows.

C2 Prudency Audit: On September 3, 2009, a consulting firm hired by the DPUC to perform a prudency audit of certain costs incurred in the implementation of a new customer service system (C2) at CL&P provided its final audit report. This report concluded that the overall project was properly managed by CL&P and the cost was no greater than the alternatives. To date, the DPUC has not opened a docket to review the results of the prudency audit, as it indicated it might do in the 2007 CL&P rate case decision. We continue to believe that our C2 expenses were prudent and will be recovered in rates and that the review of this audit will not have a material adverse impact on CL&P's earnings, financial position or cash flows.

New Hampshire:

Distribution Rates: Pursuant to an application filed by PSNH in April 2009, the NHPUC issued an order on July 31, 2009 approving a temporary increase of \$25.6 million in distribution rates on an annualized basis, effective August 1, 2009. Included in the \$25.6 million temporary increase is \$6 million to begin the recovery of PSNH's \$49.2 million deferral of storm costs incurred in December 2008.

On June 30, 2009, PSNH filed an application with the NHPUC requesting a permanent increase in distribution rates of approximately \$51 million on an annualized basis to be effective on August 1, 2009, and another \$17 million effective July 1, 2010. The case is currently in the discovery phase. Hearings before the NHPUC are scheduled for April 2010 and PSNH expects a decision in mid-2010. Any differences between temporary and permanent rates will be reconciled back to August 1, 2009.

ES, SCRC, and TCAM Rates: On July 23, 2009 and July 24, 2009, the NHPUC approved stranded cost recovery charge (SCRC) and default energy service (ES) rates of 1.14 cents and 9.03 cents per kWh, respectively, which are effective August 1, 2009 through December 31, 2009. On July 24, 2009, the NHPUC approved a transmission cost adjustment mechanism (TCAM) rate of 1.195 cents per kWh, which is effective August 1, 2009 through June 30, 2010.

On September 24, 2009, PSNH filed petitions with the NHPUC requesting changes in both its ES and SCRC annual rates for the period January 1, 2010 through December 31, 2010. Consistent with previous annual rate filings, PSNH is requesting that the NHPUC review and approve the underlying data in these filings, not a specific ES or SCRC rate. PSNH expects to petition the NHPUC using updated information in late November 2009 for specific 2010 ES and SCRC rates.

ES and SCRC Reconciliation: On an annual basis, PSNH files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. On May 1, 2009, PSNH filed its 2008 ES/SCRC reconciliation with the NHPUC, whose

evaluation includes a prudence review of PSNH's generation activities. During 2008, ES revenues exceeded ES costs by \$20.7 million, and SCRC costs exceeded SCRC revenues by \$6.4 million, resulting in an ES regulatory liability for refunds to customers and a SCRC regulatory asset for costs that will be recovered from customers. Hearings before the NHPUC are scheduled for late November 2009. We do not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's earnings, financial position or cash flows.

Massachusetts:

Customer Rates: On October 30, 2009, WMECO filed with the DPU for rate changes effective January 1, 2010. This proposal was made in accordance with WMECO's transmission and transition rates and various tracking mechanisms, and included an overall increase in customer rates of 0.313 cents per kWh, or 2.3 percent. We expect a decision by the DPU before the end of 2009.

Basic Service Rates: Effective July 1, 2009, the rates for all basic service customers decreased due to the decline in the cost of energy, as reflected in WMECO's basic service solicitations. Basic service rates for residential customers decreased from 11.805 cents per kWh to 8.554 cents per kWh, small commercial and industrial customers decreased from 12.074 cents per kWh to 9.179 cents per kWh and rates for medium and large commercial and industrial customers decreased from 7.679 cents per kWh to 7.256 cents per kWh. Effective October 1, 2009, the basic service rates for medium and large commercial and industrial customers increased from 7.256 cents per kWh to 8.210 cents per kWh.

Transition Cost Reconciliation: On July 2, 2009, WMECO filed the 2008 cost reconciliation for transition, transmission, basic/default service, basic/default service adder, and capital projects scheduling list. An evidentiary hearing has been scheduled for late November 2009. We do not expect the outcome of the DPU's review of this filing to have a material adverse impact on WMECO's earnings, financial position or cash flows.

Pension Factor Reconciliation Filing: On July 2, 2009, WMECO filed the 2008 reconciliation for its pension factor revenues and expenses. There is currently no timeline for the DPU's review of this filing. We do not expect the outcome of the DPU's review of this filing to have a material adverse impact on WMECO's earnings, financial position or cash flows.

NU Enterprises Divestitures

We have exited most of our competitive businesses. NU Enterprises continues to manage to completion its remaining wholesale marketing contracts and to manage its energy services activities.

Wholesale Marketing: During the first nine months of 2009, Select Energy continued to manage its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, that expires in 2013, and related supply contracts. In addition to the NYMPA portfolio, Select Energy has a contract to operate and purchase the output of a certain generating facility in New England through mid-2012.

Energy Services: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. Certain other businesses were wound down in 2007, and we continue to wind down minimal activity at the other energy services businesses other than E.S. Boulos Company (Boulos), an electrical contractor based in Maine that we are continuing to own and manage.

NU Enterprises Contracts

Wholesale Derivative Contracts: NU Enterprises' wholesale derivative liabilities (through its subsidiary Select Energy) are subject to mark-to-market accounting. Numerous factors could either positively or negatively affect the realization of the wholesale derivative net fair value amounts in cash. These factors include the volatility of commodity prices until the derivative contracts result in deliveries, are exited or expire, differences between expected and actual volumes, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all of its wholesale derivative energy positions to be valued daily and segregating responsibilities between the individuals actually transacting (front office) and those confirming the trades (middle office). The middle office is responsible for determining the portfolio's fair value independent from the front office.

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts as of September 30, 2009 and December 31, 2008. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are

marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as historical experience with intra-month price volatility and exit pricing assumptions. Currently, a portion of the NYMPA contract's fair value related to intra-month volatility and an exit price premium are determined based upon a model.

Generally, valuations of short-term derivative contracts derived from quotes or other external sources are more reliable should there be a need to liquidate the contracts, while valuations for longer-term derivative contracts are less certain. Accordingly, there is a risk that derivative contracts will not be realized at the amounts recorded.

The tables below disaggregate the estimated fair value of the wholesale derivative contracts. Valuations of individual contracts are broken into their component parts based upon prices actively quoted, prices provided by external sources and model-based amounts. Under accounting guidance for fair value measurements, contracts are classified in their entirety according to the lowest level for which there is at least one input that is significant to the valuation.

Therefore, all of these contracts are classified as Level 3 under this guidance. As of September 30, 2009 and December 31, 2008, the sources of the fair value of wholesale derivative contracts are included in the following tables:

Fair Value of Wholesale Contracts as of September 30, 2009

(Millions of Dollars)				
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Maturity in Excess of Four Years	Total Fair Value
Prices actively quoted	\$ (5.3)	\$ (16.6)	\$ (0.8)	\$ (22.7)
Prices provided by external sources	(1.1)	(10.3)	(1.5)	(12.9)
Model-based	(1.8)	(7.2)	(0.8)	(9.8)
Totals*	\$ (8.2)	\$ (34.1)	\$ (3.1)	\$ (45.4)

Fair Value of Wholesale Contracts as of December 31, 2008**(Millions of Dollars)**

Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Maturity in Excess of Four Years	Total Fair Value
Prices actively quoted	\$ (10.1)	\$ (7.3)	\$ (1.2)	\$ (18.6)
Prices provided by external sources	(2.7)	(21.2)	(10.0)	(33.9)
Model-based	(1.7)	(6.7)	(3.0)	(11.4)
Totals	\$ (14.5)	\$ (35.2)	\$ (14.2)	\$ (63.9)

*

Excludes cash collateral posted under master netting agreements that is required to be netted against fair value positions under GAAP.

For the three and nine months ended September 30, 2009, the changes in fair value of these contracts are included in the following table:

(Millions of Dollars)	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2009
	Total Portfolio Fair Value	Total Portfolio Fair Value
Fair value of wholesale contracts outstanding at the beginning of the period	(44.7)	\$ (63.9)
Contracts realized or otherwise settled during the period ⁽¹⁾	0.7	12.4
Change in unrealized gains included in pre-tax earnings	(1.4)	6.1
Fair value of wholesale contracts outstanding at the end of the period	(45.4)	\$ (45.4)

⁽¹⁾

Amount includes purchases, issuances and settlements of \$0.8 million and \$12.1 million for the three and nine months ended September 30, 2009, and realized intra-month (losses)/gains of \$(0.1) million and \$0.3 million for the three and nine months ended September 30, 2009.

For further information regarding Select Energy's derivative contracts, see Note 2, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. As of September 30, 2009, approximately 98 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, and approximately 2 percent was collateralized. All of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we have assessed as creditworthy. To date, this counterparty has met all of its contractual obligations.

Off-Balance Sheet Arrangements

Letters of Credit: 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. As of September 30, 2009, PSNH had posted \$70 million in such NU parent LOCs, which includes \$10 million with ISO-NE. In addition, Select Energy had posted a \$2 million NU parent LOC with ISO-NE as of September 30, 2009.

Competitive Businesses: We have various guarantees and indemnification obligations outstanding on behalf of former subsidiaries in connection with the exit from our competitive businesses. See Note 5C, "Commitments and Contingencies - Guarantees and Indemnifications," to the unaudited condensed consolidated financial statements for information regarding the maximum exposure and amounts recorded under these guarantees and indemnification obligations.

Critical Accounting Policies and Estimates Update

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 or results of operations. Our management communicates to and discusses with our Audit Committee of the Board of Trustees all critical accounting policies and estimates. The accounting policies and estimates that we believed were the most critical in nature were reported in the 2008 Form 10-K. There have been no material changes with regard to these critical accounting policies and estimates.

Other Matters

Accounting Standards Issued But Not Yet Adopted and Accounting Standards Recently Adopted: For information regarding new accounting standards, see Note 1B, "Summary of Significant Accounting Policies - Accounting Standards Issued But Not Yet Adopted," and Note 1C, "Summary of Significant Accounting Policies - Accounting Standards Recently Adopted," to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments: For updated information regarding our contractual obligations and commercial commitments as of September 30, 2009, see Note 5A, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the unaudited condensed consolidated financial statements.

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

RESULTS OF OPERATIONS - NU

The following table provides the variances in income statement line items for the unaudited condensed consolidated statements of income for NU included in this Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2009:

	Income Statement Variances (Millions of Dollars) 2009 over/(under) 2008			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	\$ (201)	(13) %	\$ (228)	(5) %
Operating Expenses:				
Fuel, purchased and net interchange power	(189)	(24)	(252)	(11)
Other operation	18	8	(23)	(3)
Maintenance	(10)	(14)	(32)	(16)
Depreciation	7	11	26	13
Amortization of regulatory assets, net	(51)	(83)	(113)	(85)
Amortization of rate reduction bonds	4	7	9	6
Taxes other than income taxes	7	10	17	8
Total operating expenses	(214)	(16)	(368)	(9)
Operating Income	13	9	140	33
Interest expense, net	(1)	(2)	6	3
Other income, net	(8)	(46)	(16)	(37)
Income before income tax expense	6	7	118	45
Income tax expense	14	66	62	90
Net Income	(8)	(11)	56	29
Preferred dividends of subsidiary	-	-	-	-
Net Income attributable to controlling interest	\$ (8)	(11) %	\$ 56	30 %

Net income attributable to controlling interests was \$56 million higher for the first nine months of 2009 as compared to the same period in 2008 due primarily to the absence in 2009 of a first quarter 2008 \$29.8 million after-tax litigation settlement charge and higher transmission and distribution earnings.

Comparison of the Third Quarter of 2009 to the Third Quarter of 2008

Operating Revenues

For the Three Months Ended September 30,				
(Millions of Dollars)	2009		2008	Variance
Electric distribution	\$ 1,082	\$	1,284	\$ (202)
Gas distribution	61		92	(31)
Total distribution	1,143		1,376	(233)
Transmission	149		110	39
Regulated companies	1,292		1,486	(194)
Competitive businesses	19		23	(4)
Other & eliminations	(5)		(2)	(3)
NU	\$ 1,306	\$	1,507	\$ (201)

Operating revenues decreased \$201 million in 2009 due primarily to lower distribution revenues from the regulated companies (\$233 million) as a result of the recovery of a lower level of electric and gas distribution fuel and other expenses passed through to customers through regulatory tracking mechanisms and lower CL&P wholesale revenues as a result of decreased market revenue related to sales of independent power producers (IPP) purchased generation output to ISO-NE.

Electric distribution revenues decreased \$202 million due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings (\$209 million), partially offset by an increase in the component of revenues that impacts earnings (\$7 million). The portion of electric distribution segment revenues that impacts earnings increased \$7 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

4.5 percent. Gas distribution revenues decreased \$31 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 5.8 percent in the third quarter of 2009 compared with the same period of 2008.

The \$209 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 (\$207 million) and revenues that are eliminated in consolidation (\$2 million). The distribution revenue tracking components decreased \$207 million due primarily to lower recovery of generation service and related congestion charges (\$157 million), lower CL&P wholesale revenues as a result of decreased market revenue related to sales of IPP purchased generation output to ISO-NE (\$51 million), and lower CL&P delivery-related FMCC (\$11 million), partially offset by higher retail transmission revenues (\$12 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 \$39 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008. Competitive businesses' revenues decreased \$4 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 expenses decreased \$189 million in 2009 due to lower costs at the regulated companies (\$196 million), partially offset by higher competitive business expenses (\$7 million). Fuel and purchased power expense from the regulated companies decreased primarily at CL&P (\$103 million) mainly due to a decrease in GSC supply costs as a result of lower sales and additional customer migration to third-party suppliers.

The decreases for PSNH, Yankee Gas, and WMECO are \$39 million, \$32 million and \$22 million, respectively. The higher competitive business expense is due primarily to the Select Energy mark-to-market expense related to the remaining wholesale contracts.

Other Operation

Other operation increased \$18 million in 2009 due primarily to higher regulated companies' distribution and transmission segment expenses (\$21 million), partially offset by lower competitive businesses' expenses (\$4 million).

Higher regulated companies' distribution and transmission segment expenses of \$21 million were due primarily to higher electric distribution segment expenses (\$13 million), higher costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$7 million), higher Yankee Gas expenses (\$4 million), and higher

transmission segment expenses (\$2 million), partially offset by transmission segment intercompany billings to the distribution segment that are eliminated in consolidation and further intercompany costs that are eliminated on an NU consolidated basis (\$6 million).

Competitive businesses' expenses were lower by \$4 million due primarily to lower Boulos expenses as a result of a lower level of work.

Maintenance

Maintenance expenses decreased \$10 million in 2009 due primarily to lower regulated companies' distribution expenses. Distribution expenses were \$10 million lower due primarily to lower PSNH generation expenses (\$4 million), lower repair and maintenance of distribution lines (\$3 million) and equipment (\$1 million).

Depreciation

Depreciation increased \$7 million in 2009 due primarily to higher regulated transmission (\$5 million) and distribution (\$3 million) plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net decreased \$51 million in 2009 for the distribution segment due primarily to lower amortization at CL&P resulting from a lower recovery of transition costs (\$50 million) as a result of lower CL&P retail CTA revenues and higher transition costs.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$4 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other than Income Taxes

Taxes other than income taxes increased \$7 million in 2009 due primarily to higher property taxes at CL&P, PSNH, and WMECO.

Interest Expense, Net

Interest expense, net decreased \$1 million in 2009 due primarily to lower RRB interest resulting from lower principal balances outstanding (\$4 million), partially offset by higher long-term debt interest (\$3 million) resulting from the issuance of new long-term debt in 2009.

Other Income, Net

Other income, net decreased \$8 million in 2009 due primarily to the absence of interest income related to a federal tax settlement in 2008 (\$10 million) and lower AFUDC equity income (\$6 million) as a result of lower eligible construction work in progress (CWIP) balances, partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust (\$9 million).

Income Tax Expense

Income tax expense increased \$14 million due primarily to higher pre-tax earnings (\$6 million) and lower tax benefits associated with lower amounts of capital expenditures.

Comparison of the First Nine Months of 2009 to the First Nine Months of 2008**Operating Revenues**

For the Nine Months Ended September 30,					
(Millions of Dollars)		2009		2008	Variance
Electric distribution	\$	3,335	\$	3,581	\$ (246)
Gas distribution		333		405	(72)
Total distribution		3,668		3,986	(318)
Transmission		419		306	113
Regulated companies		4,087		4,292	(205)
Competitive businesses		61		87	(26)
Other & eliminations		(24)		(27)	3
NU	\$	4,124	\$	4,352	\$ (228)

Operating revenues decreased \$228 million in 2009 due primarily to lower distribution revenues from the regulated companies (\$318 million) as a result of the recovery of a lower level of electric and gas distribution fuel and other expenses passed through to customers through regulatory tracking mechanisms and lower CL&P wholesale revenues as a result of decreased market revenue related to sales of IPP purchased generation output to ISO-NE.

Electric distribution revenues decreased \$246 million due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings (\$265 million), partially offset by an increase in the component of revenues that impacts earnings (\$20 million). The portion of electric distribution segment revenues that impacts earnings increased \$20 million due primarily to increases in CL&P and PSNH retail rates, partially offset by lower sales volumes. Retail electric sales for the regulated companies decreased 4 percent. Gas distribution revenues decreased \$72 million due primarily to decreased recovery of fuel costs, partially offset by higher sales volumes. Firm natural gas sales increased 8.2 percent in 2009 compared with 2008.

The \$265 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 (\$230 million) and revenues that are eliminated in consolidation (\$35 million). The distribution revenue tracking components decreased \$230 million due primarily to lower recovery of generation service and related congestion charges (\$204 million) and lower CL&P wholesale revenues as a result of decreased market revenue related to sales of IPP purchased generation output to ISO-NE (\$148 million), partially offset by higher retail transmission revenues (\$88 million) mainly as a result of the higher 2009 retail rates, higher PSNH SCRC revenues (\$18 million) and higher CL&P delivery-related FMCC (\$14 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 \$113 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008. Competitive businesses' revenues decreased \$26 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 expenses decreased \$252 million in 2009 due to lower costs at the regulated companies. Fuel and purchased power expense from the regulated companies decreased primarily at CL&P (\$97 million) mainly due to lower GSC supply costs as a result of lower sales, and Yankee Gas (\$82 million) due to a decrease in gas prices this year as compared to last year. The decreases for PSNH and WMECO are \$48 million and \$26 million, respectively.

Other Operation

Other operation decreased \$23 million in 2009 due primarily to lower NU parent and other companies' expenses (\$49 million) and lower competitive businesses' expenses (\$31 million), partially offset by higher regulated companies' distribution and transmission segment expenses (\$58 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 March 2008. Competitive businesses' expenses were lower by \$31 million due primarily to lower Boulos expenses as a result of a lower level of work.

Higher regulated companies' distribution and transmission segment expenses of \$58 million were due primarily to higher electric distribution segment expenses (\$29 million), higher costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$14 million), higher Yankee Gas expenses (\$10 million), and higher transmission segment expenses (\$9 million), partially offset by transmission segment intercompany billings to the distribution segment that are eliminated in consolidation and further intercompany costs that are eliminated on an NU consolidated basis (\$5 million).

Maintenance

Maintenance expenses decreased \$32 million in 2009 due primarily to lower regulated companies' distribution expenses (\$31 million) and lower transmission line expenses (\$2 million). Distribution expenses were lower due primarily to lower repair and maintenance of distribution lines (\$23 million), including lower storm-related expenses, lower PSNH generation expenses (\$8 million) and lower equipment maintenance expenses (\$3 million), partially offset by higher vegetation management expenses (\$5 million).

Depreciation

Depreciation increased \$26 million in 2009 due primarily to higher regulated transmission (\$19 million) and distribution (\$9 million) plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net decreased \$113 million in 2009 for the distribution segment due primarily to lower amortization at CL&P resulting from a lower recovery of transition costs (\$121 million) as a result of lower retail CTA revenues and higher transition costs, partially offset by higher amortization of the SBC balance (\$11

million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$9 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other than Income Taxes

Taxes other than income taxes increased \$17 million in 2009 due primarily to higher Connecticut gross earnings taxes recoverable in rates (\$11 million), mainly as a result of higher CL&P revenues that are subject to gross earnings tax, and higher property taxes at CL&P, PSNH, and WMECO (\$11 million), partially offset by the resolution of various routine tax issues (\$8 million).

Interest Expense, Net

Interest expense, net increased \$6 million in 2009 due primarily to higher long-term debt interest (\$26 million) resulting from the issuance of new long-term debt in 2008 and 2009, partially offset by lower RRB interest resulting from lower principal balances outstanding (\$10 million) and lower other interest (\$10 million) mostly related to the resolution of various routine tax issues.

Other Income, Net

Other income, net decreased \$16 million in 2009 due primarily to lower AFUDC equity income (\$17 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 Energy Independence Act incentives (\$5 million), partially offset by higher investment income due primarily to improved results from NU's supplemental benefit trust (\$15 million).

Income Tax Expense

Income tax expense increased \$62 million due primarily to higher pre-tax earnings (\$38 million) and lower tax benefits associated with less capital expenditures.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

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

CL&P is a wholly owned subsidiary of NU parent. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, unaudited condensed consolidated financial statements and footnotes in this Form 10-Q, the 2009 Forms 10-Q and the 2008 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the unaudited condensed consolidated statements of income for CL&P included in this Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2009:

	Income Statement Variances (Millions of Dollars) 2009 over/(under) 2008			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	\$ (121)	(12) %	\$ (89)	(3) %
Operating Expenses:				
Fuel, purchased and net interchange power	(103)	(20)	(97)	(7)
Other operation	8	6	18	4
Maintenance	(5)	(13)	(12)	(12)
Depreciation	6	14	20	17
Amortization of regulatory assets, net	(47)	(86)	(107)	(81)
Amortization of rate reduction bonds	3	7	8	7
Taxes other than income taxes	5	10	15	11
Total operating expenses	(133)	(15)	(155)	(6)
Operating Income	12	12	66	24

Interest expense, net	3	7	7	6
Other income, net	(6)	(46)	(17)	(48)
Income before income tax expense	3	4	42	21
Income tax expense	12	70	32	58
Net Income	\$ (9)	(16) %	\$ 10	7 %

Comparison of the Third Quarter of 2009 to the Third Quarter of 2008

Operating Revenues

Operating revenues decreased \$121 million due to lower distribution segment revenues (\$150 million), partially offset by higher transmission segment revenues (\$29 million).

The distribution segment revenues decreased \$150 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings (\$153 million), primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms, partially offset by an increase in the portion of revenues that impacts earnings (\$3 million).

The \$153 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 (\$150 million). The distribution revenues included in DPUC approved tracking mechanisms decreased \$150 million due primarily to a decrease in revenues associated with the recovery of GSC and supply-related FMCC (\$86 million), lower wholesale revenues as a result of decreased market revenue generated from the sale of CL&P's purchased IPP generation output to ISO-NE due to a decrease in the market price of energy (\$51 million), lower delivery-related FMCC (\$11 million) and transition cost recoveries (\$8 million), partially offset by higher retail transmission revenues (\$5 million). The lower GSC and supply-related FMCC revenue was due primarily to lower retail sales and additional customer migration to third-party suppliers in 2009 as compared to 2008. The lower delivery-related FMCC revenue was due primarily to changes in projections for certain delivery-related FMCC costs for 2009 that significantly lowered the delivery-related FMCC rate in the third quarter of 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 \$3 million primarily as a result of rate changes, partially offset by lower retail sales. Retail sales as compared to the same period in 2008 decreased 17.7 percent for the industrial, 4 percent for the commercial, and 2.4 percent for the residential classes. Total retail sales decreased overall by 5 percent.

Transmission segment revenues increased \$29 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased \$103 million due primarily to a decrease in GSC supply costs (\$119 million) and other purchased power costs (\$10 million), partially offset by higher deferred fuel (\$25 million), all of which are included in DPUC approved tracking mechanisms. The \$119 million decrease in GSC supply costs was due primarily to lower retail sales 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 \$25 million increase in deferred fuel costs was due primarily to the combined effect of a third quarter 2008 net underrecovery of GSC and FMCC expenses as compared to third quarter 2009 net overrecovery of these expenses.

Other Operation

Other operation expenses increased \$8 million due primarily to higher distribution segment expenses (\$11 million) due primarily to pension and expenses related to uncollectible receivable balances and transmission segment expenses that are tracked and recorded through FERC rate tariffs (\$2 million), partially offset by lower costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$2 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation (\$2 million).

Maintenance

Maintenance expenses decreased \$5 million in 2009 due primarily to lower repair and maintenance of overhead distribution lines (\$3 million) including lower storm expenses and lower distribution substation equipment expenses (\$1 million).

Depreciation

Depreciation expense increased \$6 million due primarily to higher utility plant balances resulting from completed construction projects placed into service in the transmission segment (\$5 million) and the distribution segment (\$2 million).

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net decreased \$47 million due primarily to lower amortization related to the recovery of transition charges (\$50 million) as a result of lower retail CTA revenue and higher transition costs, partially offset by a higher amortization of the SBC balance (\$2 million) and increased amortization of deferred taxes (\$1 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$3 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$5 million due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates primarily for the transmission segment.

Interest Expense, Net

Interest expense, net, increased \$3 million due primarily to higher long-term debt interest (\$5 million) resulting primarily from the \$250 million debt issuance in February 2009, partially offset by lower RRB interest resulting from lower principal balances outstanding (\$3 million).

Other Income, Net

Other income, net, decreased \$6 million due primarily to the absence in 2009 of interest income related to a federal tax settlement in 2008 (\$6 million), and a lower AFUDC equity income (\$5 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, partially offset by higher interest and investment income (\$5 million) due primarily to improved results from the NU supplemental benefit trust.

Income Tax Expense

Income tax expense increased \$12 million due primarily to higher pre-tax earnings (\$3 million) and lower tax benefits as a result of lower capital expenditures (\$7 million).

Comparison of the First Nine Months of 2009 to the First Nine Months of 2008

Operating Revenues

Operating revenues decreased \$89 million due to lower distribution segment revenues (\$186 million), partially offset by higher transmission segment revenues (\$97 million).

The distribution segment revenues decreased \$186 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings (\$202 million), primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation, partially offset by an increase in the portion of revenues that impacts earnings (\$16 million).

The \$202 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 (\$180 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation (\$22 million). The distribution revenues included in DPUC approved tracking mechanisms decreased \$180 million due primarily to lower wholesale revenues as a result of decreased market revenue generated from the sale of CL&P's purchased IPP generation output to ISO-NE due to a decrease in the market price of energy (\$148 million) and a decrease in revenues associated with the recovery of GSC and supply-related FMCC (\$119 million), partially offset by higher retail transmission revenues (\$68 million) and delivery-related FMCC (\$14 million). The lower GSC and supply-related FMCC revenue was due primarily to lower retail sales and additional customer migration to third-party suppliers in 2009 as compared to 2008. The higher delivery-related FMCC revenue was due primarily to a larger prior year overrecovery being refunded to customers in 2008 as compared to 2009, partially offset by lower reliability must run costs built into the 2009 rate 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 \$16 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 18.1 percent for the industrial, 3.3 percent for the commercial, and 0.5 percent for the residential classes. Total retail sales decreased overall by 3.9 percent.

Transmission segment revenues increased \$97 million due primarily to a higher transmission investment base as a result of the completion of our southwest Connecticut projects in 2008.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased \$97 million due primarily to lower GSC supply costs (\$160 million) and other purchased power costs (\$32 million), partially offset by an increase in deferred fuel costs (\$95 million), all of which are included in DPUC approved tracking mechanisms. The \$160 million decrease in GSC supply costs was due primarily to lower retail sales 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 \$95 million increase in deferred fuel costs was due primarily to the combined effect of the first nine months of 2008 net underrecovery of GSC and FMCC expenses as compared to the first nine months of 2009 net overrecovery of these expenses.

Other Operation

Other operation expenses increased \$18 million due primarily to higher distribution segment expenses (\$17 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 (\$9 million), partially offset by lower transmission segment intracompany billing to the distribution segment that are eliminated in consolidation (\$6 million) and lower costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$3 million).

Maintenance

Maintenance expenses decreased \$12 million in 2009 due primarily to lower repair and maintenance of distribution lines (\$6 million), including lower storm expenses, lower transmission segment expenses (\$2 million) and lower distribution substation equipment expenses (\$2 million).

Depreciation

Depreciation expense increased \$20 million due primarily to higher utility plant balances resulting from completed construction projects placed into service in the transmission segment (\$17 million) and the distribution segment (\$5 million).

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net decreased \$107 million due primarily to lower amortization related to the recovery of transition charges (\$121 million) as a result of lower retail CTA revenue and higher transition costs, partially offset by higher amortization of the SBC balance (\$11 million) and increased amortization of deferred taxes (\$2 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$8 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$15 million due primarily to higher gross earnings taxes recoverable in rates as a result of higher distribution and transmission revenues that are subject to gross earnings tax (\$12 million with transmission being \$5 million), higher property taxes as a result of higher plant balances and increased municipal tax rates (\$6 million) and higher payroll taxes (\$1 million), partially offset by the resolution of various routine tax issues (\$4 million).

Interest Expense, Net

Interest expense, net, increased \$7 million due primarily to higher long-term debt interest (\$22 million) 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 (\$8 million) mostly related to the resolution of various routine tax issues and lower RRB interest resulting from lower principal balances outstanding (\$7 million).

Other Income, Net

Other income, net, decreased \$17 million due primarily to lower AFUDC equity income (\$16 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 Energy Independence Act incentives (\$5 million), partially offset by higher interest and investment income (\$9 million) due primarily to improved results from the NU supplemental benefit trust.

Income Tax Expense

Income tax expense increased \$32 million due primarily to higher pre-tax earnings (\$13 million) and less tax benefits as a result of lower capital expenditures (\$11 million).

LIQUIDITY

CL&P had cash flows from operating activities, after RRB payments included in financing activities, in the first nine months of 2009 of \$343.8 million, compared with \$202.2 million in the first nine months of 2008. The improvement in 2009 cash flows was primarily due to higher operating results as a result of increased transmission revenues after significant projects were placed in service in late 2008; a shift in accounts receivable and unbilled revenue balances of \$147 million; and a decrease in the negative cash flow impact from regulatory underrecoveries of \$151 million, primarily related to the FMCC, GSC and C&LM charges included in customer rates. These factors were partially offset by increases of \$96 million and \$58 million in the negative cash flow effect of our accounts payable balances related to operating activities and the change in the amount of income tax refunds or payments, respectively. We project cash flows provided by operating activities at CL&P of approximately \$450 million in 2009, after approximately \$183 million of RRB payments.

In 2009, CL&P reduced its borrowings under the \$400 million credit facility it shares with the other regulated companies by \$155 million to \$33 million as of September 30, 2009. CL&P can borrow up to \$200 million under this facility. Other financing activities for the first nine months of 2009 included the \$250 million bond issuance in February 2009, the remarketing of \$62 million of tax-exempt PCRBs and cash capital contributions from NU parent of \$116.6 million, offset by \$102.7 million in repayment of NU Money Pool borrowings and \$85.4 million in common dividends paid to NU parent.

Cash capital expenditures included on the accompanying unaudited condensed 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 \$331.6 million in the first nine months of 2009, compared with \$678.6 million in the first nine months of 2008. This decrease was primarily the result of lower transmission segment capital expenditures in 2009 due to the completion in 2008 of three major transmission projects in southwest Connecticut. Other investing activities for the first nine months of 2009 included lendings to the NU Money Pool of \$90 million.

We project capital expenditures at CL&P of \$441 million in 2010, as compared to our current projection of \$429 million for 2009. We also project cash flows provided by operating activities at CL&P of approximately \$440 million in 2010, after RRB payments.

While the impact of continued market volatility and the extent and impacts of the current economic downturn cannot be predicted, we believe that CL&P currently has operating flexibility and access to funding sources to maintain adequate liquidity. On October 9, 2009, Fitch concluded its annual review of NU parent and its electric utilities, including CL&P, by reaffirming all of its existing credit ratings and stable outlooks. Other agencies' credit outlooks for CL&P are also stable. CL&P has low risk of calls for collateral due to its business model, as described under "Liquidity-Impact of Financial Market Conditions" in this "Management's Discussion and Analysis of Financial Condition and Results of Operations." Capital contributions from NU parent and other internal sources of funding are provided to CL&P as necessary. CL&P has the mandatory tender of \$62 million in 2010, which it plans to remarket in the ordinary course, but does not have any long-term debt maturing until 2014, and there are no CL&P debt issuances planned for 2010.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

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

PSNH is a wholly owned subsidiary of NU parent. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, unaudited condensed consolidated financial statements and footnotes in this Form 10-Q, the 2009 Forms 10-Q and the 2008 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the unaudited condensed consolidated statements of income for PSNH included in this Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2009:

	Income Statement Variances (Millions of Dollars) 2009 over/(under) 2008			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	\$ (26)	(9) %	\$ (21)	(2) %
Operating Expenses:				
Fuel, purchased and net interchange power	(39)	(24)	(49)	(11)
Other operation	9	19	21	14
Maintenance	(4)	(17)	(17)	(23)
Depreciation	1	9	5	11
Amortization of regulatory assets/(liabilities), net	-	-	8	82
Amortization of rate reduction bonds	1	6	1	3
Taxes other than income taxes	1	12	3	10

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Total operating expenses	(31)	(11)	(28)	(4)
Operating Income	5	16	7	8
Interest expense, net	(2)	(13)	(3)	(7)
Other income, net	(1)	(17)	1	22
Income before income tax expense	6	32	11	18
Income tax expense	4	94	5	32
Net Income	\$ 2	13 %	\$ 6	12 %

Comparison of the Third Quarter of 2009 to the Third Quarter of 2008

Operating Revenues

Operating revenues decreased \$26 million in 2009 due to lower distribution segment revenues (\$32 million), partially offset by higher transmission segment revenues (\$6 million).

The distribution segment revenues decreased \$32 million due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings (\$35 million) as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms. The component of revenues that impacts earnings increased \$3 million primarily as a result of higher retail rates, partially offset by lower retail sales volumes. Retail sales decreased 3.8 percent in 2009 compared to the same period in 2008.

The \$35 million decrease in distribution revenues that does not impact earnings is due to the portion of retail revenues that is included in NHPUC approved tracking mechanisms that recover certain incurred costs through PSNH's tariffs.

The decrease was due primarily to lower energy supply costs (\$49 million), partially offset by an increase in the SCRC (\$8 million), higher retail transmission revenues (\$3 million) and higher Northern Wood Power Plant renewable energy certificate revenues (\$3 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 \$6 million due primarily to a higher transmission investment base.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs decreased \$39 million due primarily to an increased level of migration of ES customers to competitive supply and lower retail sales.

Other Operation

Other operation expenses increased \$9 million due primarily to higher retail transmission expenses that are recovered through a tracking mechanism (\$5 million) and higher distribution segment expenses (\$4 million) mainly as a result of higher administrative and general expenses, including higher pension costs, and higher expenses related to uncollectible receivable balances.

Maintenance

Maintenance expenses decreased \$4 million due primarily to generation expenses incurred in 2008 primarily as a result of the Merrimack Station maintenance outages (\$3 million) and hydro expenses incurred primarily as a result of two major dam resurfacing projects (\$1 million).

Depreciation

Depreciation expense increased \$1 million due primarily to higher utility plant balances resulting from completed construction projects placed into service in the transmission segment.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$1 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$1 million due primarily to higher property taxes as a result of higher net plant balances and increased local municipal tax rates.

Interest Expense, Net

Interest expense, net decreased \$2 million due primarily to lower long-term debt interest (\$1 million), resulting from lower interest rates on a variable rate PCRB, and lower RRB interest resulting from lower principal balances outstanding (\$1 million).

Other Income, Net

Other income, net decreased \$1 million in 2009 due primarily to the absence of interest income related to a 2008 federal tax settlement, partially offset by higher investment income due primarily to improved results from the NU supplemental benefit trust.

Income Tax Expense

Income tax expense increased \$4 million due primarily to higher pre-tax earnings (\$2 million) and depreciation deduction adjustments (\$2 million).

Comparison of the First Nine Months of 2009 to the First Nine Months of 2008

Operating Revenues

Operating revenues decreased \$21 million in 2009 due to lower distribution segment revenues (\$31 million), partially offset by higher transmission segment revenues (\$9 million).

The distribution segment revenues decreased \$31 million due primarily to a decrease in the portion of electric distribution revenues that does not impact earnings (\$33 million) as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation. The component of revenues that impacts earnings increased \$2 million primarily as a result of higher retail rates, partially offset by lower retail sales volumes. Retail sales decreased 3.8 percent in 2009 compared to the same period in 2008.

The \$33 million decrease in distribution revenues that does not impact earnings is due to the portion of retail revenues that is included in NHPUC approved tracking mechanisms that recover certain incurred costs through PSNH's tariffs (\$24 million) and intracompany revenues that are eliminated in consolidation (\$9 million). The distribution revenues included in NHPUC approved tracking mechanisms decreased \$24 million due primarily to lower energy supply costs (\$58 million), partially offset by an increase in the SCRC (\$18 million), higher retail transmission revenues (\$9 million), higher Northern Wood Power Plant renewable energy certificate revenues (\$7 million), and higher wholesale revenue (\$1 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 \$9 million due primarily to a higher transmission investment base.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs decreased \$49 million 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 Operation

Other operation expenses increased \$21 million due primarily to higher distribution segment expenses (\$14 million) mainly due to higher administrative and general expenses, including higher pension costs, and higher expenses related to uncollectible receivable balances, higher generation business costs that are recovered through distribution tracking mechanisms (\$5 million) and higher retail transmission expenses that are also recovered through distribution tracking mechanisms (\$4 million).

Maintenance

Maintenance expenses decreased \$17 million due primarily to lower distribution maintenance (\$12 million), including lower storm costs, and generation expenses incurred in 2008 primarily as a result of the Merrimack Station maintenance outages (\$7 million) and hydro expenses incurred primarily as a result of two major dam resurfacing projects (\$1 million), partially offset by higher vegetation management expenses (\$4 million).

Depreciation

Depreciation expense increased \$5 million 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 increased \$8 million due primarily to an increase in net deferrals associated with PSNH's SCRC tracking mechanism, partially offset by a decrease in net deferrals associated with the ES and TCAM tracking mechanisms.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$1 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$3 million due primarily to higher property taxes as a result of higher net plant balances and increased local municipal tax rates (\$4 million), partially offset by lower sales taxes as a result of the resolution of various routine tax issues (\$1 million).

Interest Expense, Net

Interest expense, net decreased \$3 million due primarily to lower RRB interest resulting from lower principal balances outstanding (\$2 million) and lower other interest (\$1 million), mainly related to the favorable resolution of various routine tax issues.

Other Income, Net

Other income, net increased \$1 million due primarily to higher investment income related to improved results from the NU supplemental benefit trust and higher interest income related to the return on the December 2008 ice storm, partially offset by lower interest income as a result of the absence in 2009 of the 2008 federal tax settlement and lower AFUDC equity income due to higher short-term debt, which results in a lower rate based on borrowing costs.

Income Tax Expense

Income tax expense increased \$5 million due primarily to higher pre-tax earnings (\$3 million) and depreciation deduction adjustments (\$2 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in the first nine months of 2009 of \$66.7 million, compared with \$64.7 million in the first nine months of 2008, both after RRB payments. The increase in 2009 cash flows was due to improved operating results excluding non-cash factors, such as depreciation expense, insurance settlement proceeds for the recovery of major storm costs and a decrease in the negative cash flow impact from various other working capital items, such as accrued income taxes of \$25 million. These factors were offset by an increase of \$76.5 million in the negative cash flow effect of accounts payable balances as a result of, among other things, costs related to the major storm in December 2008 that were paid to vendors in 2009 and deferred. These costs began to be recovered from customers on August 1, 2009 at an annual rate of \$6 million pursuant to the temporary rate case settlement. This level of recovery could be modified once PSNH's permanent rate case is decided.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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

WMECO is a wholly owned subsidiary of NU parent. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, unaudited condensed consolidated financial statements and footnotes in this Form 10-Q, the 2009 Forms 10-Q and the 2008 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the unaudited condensed consolidated statements of income for WMECO included in this Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2009:

	Income Statement Variances (Millions of Dollars) 2009 over/(under) 2008			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	\$ (16)	(14) %	\$ (22)	(7) %
Operating Expenses:				
Fuel, purchased and net interchange power	(22)	(34)	(26)	(14)
Other operation	3	17	7	12
Maintenance	(1)	(11)	(2)	(15)
Depreciation	1	8	1	7
Amortization of regulatory (liabilities)/assets, net	(4)	(a)	(14)	(a)
Amortization of rate reduction bonds	-	-	1	7
Taxes other than income taxes	1	27	1	9
Total operating expenses	(22)	(22)	(32)	(11)

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Operating Income	6	59	10	28
Interest expense, net	-	-	-	-
Other income, net	(1)	(88)	(1)	(47)
Income before income tax expense	5	69	9	40
Income tax expense	2	87	3	45
Net Income	\$ 3	63 %	\$ 6	38 %

(a) Percent greater than 100.

Comparison of the Third Quarter of 2009 to the Third Quarter of 2008

Operating Revenues

Operating revenues decreased \$16 million in 2009 due to lower distribution segment revenues (\$20 million), partially offset by higher transmission segment revenues (\$4 million).

The distribution segment revenues decreased \$20 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings (\$22 million), primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms, partially offset by an increase in the portions of revenues that impacts earnings (\$2 million).

The \$22 million distribution segment revenue decrease that does not impact earnings was due 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 due primarily to lower energy supply costs (\$22 million), lower transition cost recoveries (\$2 million), and lower wholesale revenues (\$2 million), partially offset by higher retail transmission 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.

The portion of revenues that impacts earnings increased \$2 million due primarily to the absence in 2009 of a 2008 service quality (SQ) performance assessment charge, partially offset by lower retail sales. WMECO became subject to a SQ performance assessment charge in the third quarter of 2008 as a result of its reliability performance against the SQ metrics primarily as a result of significant

storm activity. The 2009 retail sales as compared to the same period in 2008 decreased 9.3 percent for the industrial, 2.1 percent for the commercial, and was flat for the residential classes. Total retail sales decreased overall by 2.7 percent.

Transmission segment revenues increased \$4 million due primarily to a higher transmission investment base.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased \$22 million due primarily to lower Basic/Default Service supply costs resulting from lower supplier contract rates and reduced load volumes (\$28 million). This decrease was partially offset by higher deferral of excess Basic/Default Service revenue over Basic/Default Service expense (\$7 million). The Basic/Default Service supply costs are the contractual amounts we must pay to various suppliers that serve Basic/Default Service load after winning a competitive solicitation process. 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.

Other Operation

Other operation expenses increased \$3 million due primarily to higher retail transmission costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$4 million), partially offset by lower distribution segment expenses (\$1 million) mainly as a result of lower administrative and general expenses.

Maintenance

Maintenance expenses decreased \$1 million due primarily to lower repair and maintenance of distribution lines including lower storm expenses.

Depreciation

Depreciation expense increased \$1 million due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased \$4 million in 2009 due primarily to the deferral of allowed distribution segment transition costs that are in excess of transition revenues, resulting from a decrease in the transition cost portion rate and lower IPP revenue than previous years.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$1 million due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates.

Other Income, Net

Other income, net, decreased \$1 million due primarily to lower interest income as a result of a 2009 tax refund adjustment and the absence in 2009 of interest income related to a federal tax settlement in 2008.

Income Tax Expense

Income tax expense increased \$2 million due primarily to higher pre-tax earnings.

Comparison of the First Nine Months of 2009 to the First Nine Months of 2008

Operating Revenues

Operating revenues decreased \$22 million in 2009 due to lower distribution segment revenues (\$29 million), partially offset by higher transmission segment revenues (\$6 million).

The distribution segment revenues decreased \$29 million due primarily to a decrease in the portion of distribution revenues that does not impact earnings (\$30 million), primarily as a result of the inclusion of these distribution revenues in regulatory tracking mechanisms and intracompany revenues that are eliminated in consolidation, partially offset by an increase in the portions of revenues that impacts earnings (\$2 million).

The \$29 million distribution segment revenue 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 (\$26 million) and transmission segment intracompany billings to the distribution segment that are eliminated in consolidation (\$4 million). The distribution revenues included in DPU approved tracking mechanisms decreased \$26 million due primarily to lower energy supply costs (\$27 million), lower transition cost recoveries (\$7 million), and lower wholesale revenues (\$5 million), partially offset by higher retail transmission revenues (\$11 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 portion of revenues that impacts earnings increased \$2 million due primarily to the absence in 2009 of a SQ performance assessment charge as further described above, partially offset by lower retail sales. The 2009 retail sales as compared to the same period in 2008 decreased 13.5 percent for the industrial, 5.2 percent for the commercial, and 1.3 percent for the residential classes. Total retail sales decreased overall by 5.3 percent.

Transmission segment revenues increased \$6 million due primarily to a higher transmission investment base.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased \$26 million due primarily to lower Basic/Default Service supply costs (\$30 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 (\$6 million). The Basic/Default Service supply costs are the contractual amounts we must pay to various suppliers that serve Basic/Default Service 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 Operation

Other operation expenses increased \$7 million due primarily to higher retail transmission and other costs that are recovered through distribution tracking mechanisms and have no earnings impact (\$8 million) and higher transmission segment expenses (\$1 million), partially offset by lower distribution segment expenses (\$2 million) mainly as a result of lower administrative and general expenses.

Maintenance

Maintenance expenses decreased \$2 million due primarily to lower repair and maintenance of distribution lines including lower storm expenses.

Depreciation

Depreciation expense increased \$1 million due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased \$14 million in 2009 due primarily to the deferral of allowed distribution segment transition costs that are in excess of transition revenues, resulting from a decrease in the transition cost portion rate and lower IPP revenue than previous years.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased \$1 million in 2009, which corresponded to the reduction in principal of the RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased \$1 million due primarily to higher property taxes as a result of higher plant balances and increased municipal tax rates.

Other Income, Net

Other income, net, decreased \$1 million due primarily to a 2009 tax refund adjustment to interest income (\$1 million), the absence in 2009 of interest income related to a federal tax settlement in 2008 (\$1 million), and lower AFUDC equity income (\$1 million). Although CWIP has increased over the prior year due to the NEEWS transmission project, there has been no 2009 equity AFUDC as CWIP has been fully funded by short-term debt for the last seven months. These factors were partially offset by higher investment income (\$2 million) due primarily to improved results from the NU supplemental benefit trust.

Income Tax Expense

Income tax expense increased \$3 million due primarily to higher pre-tax earnings.

LIQUIDITY

WMECO had cash flows provided by operating activities in the first nine months of 2009 of \$27.7 million, compared with \$29.2 million in the first nine months of 2008, both after RRB payments. The decrease in 2009 cash flows was due to an increase of \$31.6 million in the negative cash flow effect of accounts payable balances partially as a result of costs related to the major storm in December 2008 that were paid to vendors in 2009. These costs were deferred and are expected to be recovered from customers. WMECO anticipates filing a distribution rate case in mid-2010, which would include a request for more timely recovery of the December 2008 storm costs. The above timing impact was offset by a decrease in the negative cash flow impact from various other

working capital items, such as accrued income taxes or taxes receivable of \$14 million and accounts receivable and unbilled revenues of \$7.8 million, and improved operating results excluding non-cash factors, such as depreciation expense.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

Commodity Price Risk Management: We have no contracts entered into for trading purposes. 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, and the sensitivity analyses below do not include these contracts. The wholesale portfolio held by Select Energy includes contracts that are market-risk sensitive, including a wholesale sales contract with NYMPA through 2013 with approximately 0.4 million remaining megawatt-hours (MWh) of supply contract volumes, net of related sales volumes. Select Energy also has a non-derivative contract that expires in mid-2012 to purchase output from a generation facility, which is less exposed to market price volatility and is not included in the sensitivity analysis below. As Select Energy's contract volumes are winding down, and as the NYMPA contract is substantially hedged against price risks, we have somewhat limited exposure to commodity price risks.

For Select Energy's wholesale portfolio derivatives, we utilize the sensitivity analysis methodology to disclose quantitative information for our commodity price risks (including, where applicable, capacity and ancillary components). 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. Under the sensitivity analysis, the fair value of the derivatives is a function of the underlying commodity components, contract prices and market prices represented by each derivative contract. For swaps, forward contracts and options, fair value reflects our best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Exchange-traded futures and options are recorded at fair value based on closing exchange prices. A portion of the fair value of the NYMPA contract is based on a model.

Select Energy's Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of the wholesale portfolio, which includes several derivative contracts, which would result from a hypothetical change in the future market price of electricity, the fair values of the contracts are determined from models that take into consideration estimated future market prices of electricity, the volatility of the market prices in each period, as well as the time value factors of the underlying commitments.

Hypothetical changes in the fair value of derivative contracts in the wholesale portfolio were determined using a 30 percent assumed change in forward market prices. As of September 30, 2009, we determined the following

hypothetical changes and calculated the nominal adjusted impact on pre-tax earnings:

(Millions of Dollars) Commodity	30% Price Increase	30% Price Decrease
	Nominal Impact on Pre-Tax Earnings	Nominal Impact on Pre-Tax Earnings
Energy	\$ 0.2	\$ (4.3)
Capacity	(2.0)	2.0
Ancillaries	(1.6)	1.6
	\$ (3.4)	\$ (0.7)

The impact of a change in electricity prices on wholesale derivative transactions as of September 30, 2009 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. The derivative contracts in the wholesale portfolio are accounted for at fair value, and changes in market prices impact earnings.

Other Risk Management Activities

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 September 30, 2009, 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 September 30, 2009, we maintained a fixed-to-floating interest rate swap at NU parent to manage the interest rate risk 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.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is comprised of members of management from other areas of NU that do not create these risk exposures and functions to ensure compliance with our stated risk management policies.

We track and re-balance the risk in our portfolio in accordance with fair value and other risk management methodologies that utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

The NYMEX traded futures and option contracts cleared off the NYMEX exchange are ultimately guaranteed by NYMEX to Select Energy. Select Energy has established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements 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.

Due to the exposure of counterparties to Select Energy, Select Energy had cash collateral balances deposited with its NYMEX broker of \$29.3 million and \$26.3 million as of September 30, 2009 and December 31, 2008, respectively, which are included in Current assets - prepayments and other on the accompanying unaudited condensed consolidated balance sheets. As of September 30, 2009, Select Energy also had \$0.9 million of collateral posted with counterparties under a master netting agreement. This collateral is netted against the fair value of derivatives. Select Energy held no collateral balances from counterparties at either period end. In addition, Select Energy had posted a \$2 million NU parent LOC as of September 30, 2009 in favor of ISO-NE.

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 September 30, 2009, CL&P had \$1 million in cash collateral deposited with counterparties that has been netted against the fair value of the related derivative. As of December 31, 2008, our regulated companies neither held cash collateral nor deposited 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. As of September 30, 2009, PSNH had posted \$70 million in such NU parent LOCs.

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks of the Company. ERM 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 ERM process will identify or manage every risk or event that could impact our financial condition or results of operations. The findings of this process are periodically discussed with our Board of Trustees.

Additional quantitative and qualitative disclosures about market risk are set forth in Part I, Item 2, "Management's Discussion and Analysis of Financial Condition and Results of Operations," included in this Quarterly Report on Form 10-Q.

ITEM 4.

CONTROLS AND PROCEDURES

Management, on behalf of NU, CL&P, PSNH, and WMECO, evaluated the design and operation of the disclosure controls and procedures as of September 30, 2009 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Securities Exchange Act of 1934 and the rules and regulations of the SEC. This evaluation was made under management's supervision and with management's participation, including the principal executive officers and principal financial officer as of the end of the period covered by this Quarterly Report on Form 10-Q. There are inherent limitations of disclosure controls and procedures, including the possibility of human error and the circumventing or overriding of the controls and procedures.

Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. The principal executive 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 regulations 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 disclosures.

There have been no changes in internal controls over financial reporting for NU, CL&P, PSNH, and WMECO during the quarter ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1.

LEGAL PROCEEDINGS

We are parties to various legal proceedings. We have identified these legal proceedings in Part I, Item 3, "Legal Proceedings," and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2008, and updated them in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, all of which disclosures are incorporated herein by reference. There have been no material changes with regard to the legal proceedings previously disclosed in our most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q.

ITEM 1A.

RISK FACTORS

We are subject to a variety of significant risks in addition to the matters set forth under "Forward Looking Statements," in "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this Quarterly Report on Form 10-Q. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009, all of which risk factors are incorporated herein by reference. These risk factors should be considered carefully in evaluating our risk profile. There have been no additional risk factors identified and no material changes with regard to the risk factors previously disclosed in our most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q.

ITEM 2.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

There were no purchases made by or on behalf of NU or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934) of NU common shares during the quarter ended September 30, 2009.

ITEM 6.

EXHIBITS

Exhibit No.

Description

Listing of Exhibits (NU)

12

Ratio of Earnings to Fixed Charges

15

Deloitte & Touche LLP Letter Regarding Unaudited Financial Information

31

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Executive Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

Listing of Exhibits (CL&P)

12

Ratio of Earnings to Fixed Charges

31

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Executive Vice President and Chief Financial Officer of The Connecticut Light and Power Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

Listing of Exhibits (PSNH)

12

Ratio of Earnings to Fixed Charges

31

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Executive Vice President and Chief Financial Officer of Public Service Company of New Hampshire, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

Listing of Exhibits (WMECO)

12

Ratio of Earnings to Fixed Charges

31

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

31.1

Certification of David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Executive Vice President and Chief Financial Officer of Western Massachusetts Electric Company, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated November 6, 2009

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NORTHEAST UTILITIES

(Registrant)

Date: November 6, 2009

By /s/

David R. McHale

David R. McHale

Executive Vice President and Chief Financial Officer

(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

Date: November 6, 2009

By /s/

David R. McHale

David R. McHale

Executive Vice President and Chief Financial Officer

(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

(Registrant)

Date: November 6, 2009

By /s/

David R. McHale

David R. McHale

Executive Vice President and Chief Financial Officer

(for the Registrant and as Principal Financial Officer)

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY

(Registrant)

Date: November 6, 2009

By /s/

David R. McHale

David R. McHale

Executive Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)