CONNECTICUT LIGHT & POWER CO
Form 10-Q
November 07, 2011

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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2011
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street	02-0181050

Manchester, New Hampshire 03101-1134
Telephone: (603) 669-4000

0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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
ü	

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (check one):

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
Northeast Utilities	ü		
The Connecticut Light and Power Company			ü
Public Service Company of New Hampshire			ü
Western Massachusetts Electric Company			ü

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

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

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

Company - Class of Stock	Outstanding as of October 31, 2011
Northeast Utilities Common shares, $5.00 par value	177,032,294 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 abbreviations or acronyms that are found in this report.

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

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

REGULATORS:

DEEP	Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
EPA	U.S. Environmental Protection Agency
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Public Utility Regulatory Authority
SEC	Securities and Exchange Commission

OTHER:

2010 Form 10-K	The Northeast Utilities and subsidiaries 2010 combined Annual Report on Form 10-K as filed with the SEC
2010 Healthcare Act	Patient Protection and Affordable Care Act
2010 Tax Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act
AOCI	Accumulated Other Comprehensive Income/(Loss)
AFUDC	Allowance For Funds Used During Construction
C&LM	Conservation and Load Management
Clean Air Project	The construction of a wet flue gas desulphurization system, known as "scrubber technology", to reduce mercury emissions of the Merrimack coal-fired generation station in Bow, New Hampshire
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge

FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IASB	International Accounting Standards Board
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
KV	Kilovolt
KWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Last resort service
MGP	Manufactured Gas Plant
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
NEEWS	New England East-West Solution
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PPA	Pension Protection Act
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
RMR	Reliability Must Run
ROE	Return on Equity
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge

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

TABLE OF CONTENTS

Western Massachusetts Electric Company and Subsidiary

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NORTHEAST UTILITIES AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Thousands of Dollars)	September 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 16,721	$ 23,395
Receivables, Net	494,552	523,644
Unbilled Revenues	138,110	208,834
Taxes Receivable	203	89,638
Fuel, Materials and Supplies	237,794	244,043
Regulatory Assets	235,460	238,699
Marketable Securities	74,525	78,306
Prepayments and Other Current Assets	130,010	100,441
Total Current Assets	1,327,375	1,507,000
Property, Plant and Equipment, Net	10,096,063	9,567,726
Deferred Debits and Other Assets:		
Regulatory Assets	2,706,053	2,756,580
Goodwill	287,591	287,591
Marketable Securities	52,181	51,201
Derivative Assets	91,430	123,242
Other Long-Term Assets	168,024	179,261
Total Deferred Debits and Other Assets	3,305,279	3,397,875
Total Assets	$ 14,728,717	$ 14,472,601

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, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Banks	$ 30,000	$ 267,000
Long-Term Debt - Current Portion	334,327	66,286
Accounts Payable	476,214	417,285
Obligations to Third Party Suppliers	77,760	74,659
Accrued Taxes	115,285	107,067
Accrued Interest	77,319	74,740
Regulatory Liabilities	174,562	99,403
Derivative Liabilities	110,653	71,501
Other Current Liabilities	139,187	167,206
Total Current Liabilities	1,535,307	1,345,147
Rate Reduction Bonds	130,374	181,572
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,814,976	1,636,750
Regulatory Liabilities	276,222	339,655
Derivative Liabilities	909,252	909,668
Accrued Pension	701,993	802,195
Other Long-Term Liabilities	671,046	695,915
Total Deferred Credits and Other Liabilities	4,373,489	4,384,183
Capitalization:		
Long-Term Debt	4,614,697	4,632,866
Noncontrolling Interest in Consolidated Subsidiary:		
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Equity:		
Common Shareholders' Equity:		
Common Shares	980,054	978,909
Capital Surplus, Paid In	1,792,593	1,777,592
Retained Earnings	1,587,528	1,452,777
Accumulated Other Comprehensive Loss	(55,214)	(43,370)
Treasury Stock	(348,764)	(354,732)
Common Shareholders' Equity	3,956,197	3,811,176
Noncontrolling Interests	2,453	1,457
Total Equity	3,958,650	3,812,633
Total Capitalization	8,689,547	8,561,699

Total Liabilities and Capitalization	$	14,728,717	$	14,472,601

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

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

(Thousands of Dollars, Except Share Information)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating Revenues	$ 1,114,892	$ 1,243,337	$ 3,397,624	$ 3,694,182
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	399,941	494,125	1,214,350	1,539,703
Other Operating Expenses	237,576	233,472	752,372	688,409
Maintenance	58,949	49,951	205,538	162,405
Depreciation	75,196	70,954	222,784	228,685
Amortization of Regulatory Assets, Net	36,740	50,341	88,409	50,908
Amortization of Rate Reduction Bonds	17,680	60,434	52,047	175,000
Taxes Other Than Income Taxes	84,994	84,427	252,817	244,431
Total Operating Expenses	911,076	1,043,704	2,788,317	3,089,541
Operating Income	203,816	199,633	609,307	604,641
Interest Expense:				
Interest on Long-Term Debt	57,461	57,802	171,905	173,594
Interest on Rate Reduction Bonds	2,018	4,661	6,889	16,985
Other Interest	4,453	3,435	5,922	9,778
Interest Expense	63,932	65,898	184,716	200,357
Other Income, Net	1,430	10,118	19,077	19,726
Income Before Income Tax Expense	141,314	143,853	443,668	424,010
Income Tax Expense	49,883	41,918	157,934	161,126
Net Income	91,431	101,935	285,734	262,884
Net Income Attributable to Noncontrolling Interests	1,470	1,411	4,340	4,204
Net Income Attributable to Controlling Interests	$ 89,961	$ 100,524	$ 281,394	$ 258,680
Basic Earnings Per Common Share	$ 0.51	$ 0.57	$ 1.59	$ 1.47
Diluted Earnings Per Common Share	$ 0.51	$ 0.57	$ 1.58	$ 1.46
Dividends Declared Per Common Share	$ 0.28	$ 0.26	$ 0.83	$ 0.77

Weighted Average Common Shares Outstanding:				
Basic	177,497,862	176,752,714	177,344,481	176,557,889
Diluted	177,835,348	177,012,278	177,647,694	176,762,088

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, 2011	2010
Operating Activities:		
Net Income	$ 285,734	$ 262,884
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	12,435	24,632
Depreciation	222,784	228,685
Deferred Income Taxes	133,528	105,070
Pension and PBOP Expense	103,106	74,744
Pension and PBOP Contributions	(159,220)	(78,035)
Regulatory (Underrecoveries)/Overrecoveries, Net	(26,001)	44,479
Amortization of Regulatory Assets, Net	88,409	50,908
Amortization of Rate Reduction Bonds	52,047	175,000
Derivative Assets and Liabilities	(33,767)	(9,228)
Other	(14,802)	(46,190)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	61,657	20,905
Fuel, Materials and Supplies	(4,072)	33,337
Taxes Receivable/Accrued	109,410	(12,904)
Accounts Payable	66,618	(59,601)
Other Current Assets and Liabilities	(9,419)	28,961
Net Cash Flows Provided by Operating Activities	888,447	843,647
Investing Activities:		
Investments in Property, Plant and Equipment	(749,060)	(677,579)
Proceeds from Sales of Marketable Securities	116,463	146,305
Purchases of Marketable Securities	(118,251)	(148,075)
Proceeds from Sale of Assets	46,841	-
Other Investing Activities	(5,849)	(10,412)
Net Cash Flows Used in Investing Activities	(709,856)	(689,761)
Financing Activities:		
Cash Dividends on Common Shares	(145,865)	(135,349)
Cash Dividends on Preferred Stock	(4,169)	(4,169)
(Decrease)/Increase in Short-Term Debt	(237,000)	55,687
Issuance of Long-Term Debt	382,000	145,000
Retirements of Long-Term Debt	(124,086)	(4,286)
Retirements of Rate Reduction Bonds	(51,198)	(195,724)
Other Financing Activities	(4,947)	(818)
Net Cash Flows Used in Financing Activities	(185,265)	(139,659)
Net (Decrease)/Increase in Cash and Cash Equivalents	(6,674)	14,227

Cash and Cash Equivalents - Beginning of Period		23,395		26,952
Cash and Cash Equivalents - End of Period	$	16,721	$	41,179

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, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	7,236	$	9,762
Receivables, Net		305,426		317,530
Accounts Receivable from Affiliated Companies		535		822
Notes Receivable from Affiliated Companies		6,925		-
Unbilled Revenues		81,224		116,392
Taxes Receivable		-		48,360
Regulatory Assets		170,338		157,530
Materials and Supplies		63,110		63,811
Accumulated Deferred Income Taxes		20,550		-
Prepayments and Other Current Assets		49,921		27,466
Total Current Assets		705,265		741,673
Property, Plant and Equipment, Net		5,729,334		5,586,504
Deferred Debits and Other Assets:				
Regulatory Assets		1,755,094		1,721,416
Derivative Assets		88,099		115,870
Other Long-Term Assets		107,953		89,729
Total Deferred Debits and Other Assets		1,951,146		1,927,015
Total Assets	$	8,385,745	$	8,255,192

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, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ -	$ 6,225
Long-Term Debt - Current Portion	62,000	62,000
Accounts Payable	248,449	204,868
Accounts Payable to Affiliated Companies	60,612	53,207
Obligations to Third Party Suppliers	69,877	68,692
Accrued Taxes	102,167	92,061
Accrued Interest	35,331	42,548
Regulatory Liabilities	111,895	75,716
Derivative Liabilities	93,987	46,781
Other Current Liabilities	44,705	46,209
Total Current Liabilities	829,023	698,307
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	1,166,140	1,068,344
Regulatory Liabilities	145,876	206,394
Derivative Liabilities	891,709	883,091
Accrued Pension	34,999	42,486
Other Long-Term Liabilities	307,922	321,793
Total Deferred Credits and Other Liabilities	2,546,646	2,522,108
Capitalization:		
Long-Term Debt	2,521,620	2,521,102
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200
Common Stockholder's Equity:		
Common Stock	60,352	60,352
Capital Surplus, Paid In	1,606,358	1,605,275
Retained Earnings	707,911	734,561
Accumulated Other Comprehensive Loss	(2,365)	(2,713)
Common Stockholder's Equity	2,372,256	2,397,475
Total Capitalization	5,010,076	5,034,777
Total Liabilities and Capitalization	$ 8,385,745	$ 8,255,192

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

6

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of Dollars)	2011	2010	2011	2010
Operating Revenues	$ 673,666	$ 789,249	$ 1,955,361	$ 2,292,146
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	257,645	334,230	720,178	987,604
Other Operating Expenses	128,329	127,779	401,899	382,884
Maintenance	36,004	21,056	118,655	75,715
Depreciation	39,711	38,100	117,629	133,568
Amortization of Regulatory Assets, Net	15,688	32,997	48,736	55,308
Amortization of Rate Reduction Bonds	-	43,778	-	125,985
Taxes Other Than Income Taxes	58,552	59,884	169,745	168,001
Total Operating Expenses	535,929	657,824	1,576,842	1,929,065
Operating Income	137,737	131,425	378,519	363,081
Interest Expense:				
Interest on Long-Term Debt	33,326	33,656	100,085	100,918
Interest on Rate Reduction Bonds	-	1,529	-	6,805
Other Interest	1,893	1,496	(815)	4,692
Interest Expense	35,219	36,681	99,270	112,415
Other Income/(Loss), Net	(2,356)	6,938	4,308	12,616
Income Before Income Tax Expense	100,162	101,682	283,557	263,282
Income Tax Expense	33,634	32,636	100,057	101,739
Net Income	$ 66,528	$ 69,046	$ 183,500	$ 161,543

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)

(Thousands of Dollars)	Nine Months Ended September 30, 2011	2010
Operating Activities:		
Net Income	$ 183,500	$ 161,543
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	2,115	7,088
Depreciation	117,629	133,568
Deferred Income Taxes	67,948	49,636
Pension and PBOP Expense, Net of PBOP Contributions	10,473	388
Regulatory (Underrecoveries)/Overrecoveries, Net	(50,234)	57,696
Amortization of Regulatory Assets, Net	48,736	55,308
Amortization of Rate Reduction Bonds	-	125,985
Other	(22,435)	(38,073)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	26,164	2,653
Materials and Supplies	(12,669)	3,331
Taxes Receivable/Accrued	64,779	(13,016)
Accounts Payable	73,809	(55,383)
Other Current Assets and Liabilities	(23,245)	36
Net Cash Flows Provided by Operating Activities	486,570	490,760
Investing Activities:		
Investments in Property, Plant and Equipment	(305,595)	(274,193)
(Increase)/Decrease in NU Money Pool Lending	(6,925)	97,775
Proceeds from Sale of Assets	46,841	-
Other Investing Activities	(6,693)	205
Net Cash Flows Used in Investing Activities	(272,372)	(176,213)
Financing Activities:		
Cash Dividends on Common Stock	(205,981)	(181,841)
Cash Dividends on Preferred Stock	(4,169)	(4,169)
(Decrease)/Increase in NU Money Pool Borrowings	(6,225)	26,325
Retirements of Rate Reduction Bonds	-	(147,533)
Other Financing Activities	(349)	(256)
Net Cash Flows Used in Financing Activities	(216,724)	(307,474)
Net (Decrease)/Increase in Cash	(2,526)	7,073
Cash - Beginning of Period	9,762	45
Cash - End of Period	$ 7,236	$ 7,118

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, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	2,870	$	2,559
Receivables, Net		92,381		105,070
Accounts Receivable from Affiliated Companies		2,966		858
Notes Receivable from Affiliated Companies		50,300		-
Unbilled Revenues		39,230		48,691
Taxes Receivable		-		12,564
Fuel, Materials and Supplies		107,144		116,074
Regulatory Assets		20,679		39,215
Prepayments and Other Current Assets		22,283		20,098
Total Current Assets		337,853		345,129
Property, Plant and Equipment, Net		2,181,234		2,053,281
Deferred Debits and Other Assets:				
Regulatory Assets		358,065		395,203
Other Long-Term Assets		63,637		85,508
Total Deferred Debits and Other Assets		421,702		480,711
Total Assets	$	2,940,789	$	2,879,121

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, 2011		December 31, 2010
LIABILITIES AND CAPITALIZATION				
Current Liabilities:				
Notes Payable to Banks	$	-	$	30,000
Notes Payable to Affiliated Companies		-		47,900
Accounts Payable		79,593		85,324
Accounts Payable to Affiliated Companies		16,396		20,007
Accrued Interest		14,674		10,231
Regulatory Liabilities		25,614		8,365
Derivative Liabilities		3,330		12,834
Other Current Liabilities		41,019		36,726
Total Current Liabilities		180,626		251,387
Rate Reduction Bonds		99,366		138,247
Deferred Credits and Other Liabilities:				
Accumulated Deferred Income Taxes		372,307		314,996
Regulatory Liabilities		56,551		58,631
Accrued Pension		179,402		261,096
Other Long-Term Liabilities		87,807		91,952
Total Deferred Credits and Other Liabilities		696,067		726,675
Capitalization:				
Long-Term Debt		997,670		836,365
Common Stockholder's Equity:				
Common Stock		-		-
Capital Surplus, Paid In		600,074		579,577
Retained Earnings		378,113		347,471
Accumulated Other Comprehensive Loss		(11,127)		(601)
Common Stockholder's Equity		967,060		926,447
Total Capitalization		1,964,730		1,762,812
Total Liabilities and Capitalization	$	2,940,789	$	2,879,121

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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating Revenues	$ 259,648	$ 276,976	$ 769,309	$ 773,866
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	77,939	94,137	234,413	281,161
Other Operating Expenses	52,617	53,133	163,265	172,332
Maintenance	16,208	20,933	64,771	62,560
Depreciation	18,403	17,454	54,432	49,443
Amortization of Regulatory Assets/(Liabilities), Net	17,271	14,513	35,303	(2,809)
Amortization of Rate Reduction Bonds	13,609	12,844	39,748	37,481
Taxes Other Than Income Taxes	15,133	14,191	44,034	40,616
Total Operating Expenses	211,180	227,205	635,966	640,784
Operating Income	48,468	49,771	133,343	133,082
Interest Expense:				
Interest on Long-Term Debt	8,484	8,925	25,425	27,705
Interest on Rate Reduction Bonds	1,468	2,320	5,038	7,557
Other Interest	416	208	761	572
Interest Expense	10,368	11,453	31,224	35,834
Other Income, Net	3,293	3,667	12,112	5,882
Income Before Income Tax Expense	41,393	41,985	114,231	103,130
Income Tax Expense	15,759	13,231	39,468	36,950
Net Income	$ 25,634	$ 28,754	$ 74,763	$ 66,180

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)

(Thousands of Dollars)	Nine Months Ended September 30, 2011	2010
Operating Activities:		
Net Income	$ 74,763	$ 66,180
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	5,202	7,237
Depreciation	54,432	49,443
Deferred Income Taxes	51,809	31,876
Pension and PBOP Expense	21,568	20,767
Pension and PBOP Contributions	(99,780)	(51,060)
Regulatory Overrecoveries/(Underrecoveries), Net	2,581	(5,450)
Amortization of Regulatory Assets/(Liabilities), Net	35,303	(2,809)
Amortization of Rate Reduction Bonds	39,748	37,481
Insurance Proceeds	-	10,000
Settlements of Cash Flow Hedge Instruments	(18,072)	-
Other	(15,501)	(32,525)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	9,332	(8,973)
Fuel, Materials and Supplies	11,981	28,188
Taxes Receivable/Accrued	18,758	15,066
Accounts Payable	(6,905)	(11,599)
Other Current Assets and Liabilities	14,613	21,852
Net Cash Flows Provided by Operating Activities	199,832	175,674
Investing Activities:		
Investments in Property, Plant and Equipment	(167,383)	(217,954)
Increase in NU Money Pool Lending	(50,300)	-
Other Investing Activities	1,026	(7,753)
Net Cash Flows Used in Investing Activities	(216,657)	(225,707)
Financing Activities:		
Cash Dividends on Common Stock	(44,121)	(37,938)
Decrease in Short-Term Debt	(30,000)	-
Issuance of Long-Term Debt	282,000	-
Retirements of Long-Term Debt	(119,800)	-
Decrease in NU Money Pool Borrowings	(47,900)	(100)
Capital Contributions from NU Parent	20,000	123,551
Retirements of Rate Reduction Bonds	(38,881)	(36,635)
Other Financing Activities	(4,162)	(176)
Net Cash Flows Provided by Financing Activities	17,136	48,702

Net Increase/(Decrease) in Cash		311		(1,331)
Cash - Beginning of Period		2,559		1,974
Cash - End of Period	$	2,870	$	643

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, 2011		December 31, 2010
ASSETS				
Current Assets:				
Cash	$	270	$	1
Receivables, Net		44,727		37,585
Accounts Receivable from Affiliated Companies		1,285		505
Notes Receivable from Affiliated Companies		70,700		-
Unbilled Revenues		14,058		16,578
Taxes Receivable		6		7,346
Materials and Supplies		3,596		3,664
Regulatory Assets		24,248		19,531
Marketable Securities		34,890		33,194
Prepayments and Other Current Assets		1,418		1,968
Total Current Assets		195,198		120,372
Property, Plant and Equipment, Net		986,310		817,146
Deferred Debits and Other Assets:				
Regulatory Assets		182,336		207,584
Marketable Securities		22,205		23,860
Other Long-Term Assets		33,764		30,597
Total Deferred Debits and Other Assets		238,305		262,041
Total Assets	$	1,419,813	$	1,199,559

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, 2011	December 31, 2010
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes Payable to Affiliated Companies	$ -	$ 20,400
Accounts Payable	74,288	48,344
Accounts Payable to Affiliated Companies	11,580	7,848
Accrued Interest	2,111	6,787
Regulatory Liabilities	32,617	7,959
Accumulated Deferred Income Taxes	264	5,902
Other Current Liabilities	13,423	9,842
Total Current Liabilities	134,283	107,082
Rate Reduction Bonds	31,007	43,325
Deferred Credits and Other Liabilities:		
Accumulated Deferred Income Taxes	230,668	218,063
Regulatory Liabilities	17,021	15,048
Other Long-Term Liabilities	55,099	58,169
Total Deferred Credits and Other Liabilities	302,788	291,280
Capitalization:		
Long-Term Debt	499,496	400,288
Common Stockholder's Equity:		
Common Stock	10,866	10,866
Capital Surplus, Paid In	340,046	248,044
Retained Earnings	105,599	98,757
Accumulated Other Comprehensive Loss	(4,272)	(83)
Common Stockholder's Equity	452,239	357,584
Total Capitalization	951,735	757,872
Total Liabilities and Capitalization	$ 1,419,813	$ 1,199,559

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

14

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of Dollars)	2011	2010	2011	2010
Operating Revenues	$ 104,515	$ 103,719	$ 309,589	$ 296,400
Operating Expenses:				
Fuel, Purchased and Net Interchange Power	39,194	39,922	112,015	120,274
Other Operating Expenses	22,744	27,314	75,350	73,607
Maintenance	4,001	4,915	12,987	14,825
Depreciation	6,681	5,838	19,644	17,658
Amortization of Regulatory Assets, Net	3,388	2,735	4,584	445
Amortization of Rate Reduction Bonds	4,071	3,812	12,299	11,534
Taxes Other Than Income Taxes	4,650	4,319	13,395	12,483
Total Operating Expenses	84,729	88,855	250,274	250,826
Operating Income	19,786	14,864	59,315	45,574
Interest Expense:				
Interest on Long-Term Debt	4,913	4,691	14,389	13,298
Interest on Rate Reduction Bonds	550	811	1,852	2,623
Other Interest	529	93	785	275
Interest Expense	5,992	5,595	17,026	16,196
Other Income/(Loss), Net	(722)	747	259	1,512
Income Before Income Tax Expense	13,072	10,016	42,548	30,890
Income Tax Expense	4,638	2,679	15,977	12,645
Net Income	$ 8,434	$ 7,337	$ 26,571	$ 18,245

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, 2011	2010
Operating Activities:		
Net Income	$ 26,571	$ 18,245
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Bad Debt Expense	2,352	5,602
Depreciation	19,644	17,658
Deferred Income Taxes	9,323	4,712
Regulatory Overrecoveries/(Underrecoveries), Net	20,757	(8,696)
Amortization of Regulatory Assets, Net	4,584	445
Amortization of Rate Reduction Bonds	12,299	11,534
Settlement of Cash Flow Hedge Instrument	(6,859)	-
Other	(3,396)	(4,961)
Changes in Current Assets and Liabilities:		
Receivables and Unbilled Revenues, Net	(7,804)	(2,896)
Materials and Supplies	67	(878)
Taxes Receivable/Accrued	10,675	1,203
Accounts Payable	4,294	(9,900)
Other Current Assets and Liabilities	(3,830)	(1,381)
Net Cash Flows Provided by Operating Activities	88,677	30,687
Investing Activities:		
Investments in Property, Plant and Equipment	(153,470)	(77,710)
Proceeds from Sales of Marketable Securities	96,134	94,575
Purchases of Marketable Securities	(96,312)	(94,896)
Increase in NU Money Pool Lending	(70,700)	-
Other Investing Activities	(1,664)	(754)
Net Cash Flows Used in Investing Activities	(226,012)	(78,785)
Financing Activities:		
Cash Dividends on Common Stock	(19,729)	(11,162)
Issuance of Long-Term Debt	100,000	95,000
Decrease in NU Money Pool Borrowings	(20,400)	(125,900)
Retirements of Rate Reduction Bonds	(12,318)	(11,557)
Capital Contributions from NU Parent	91,812	102,600
Other Financing Activities	(1,761)	(883)
Net Cash Flows Provided by Financing Activities	137,604	48,098
Net Increase in Cash	269	-
Cash - Beginning of Period	1	1

Cash - End of Period	$	270	$	1

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)

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

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A.

Pending Merger with NSTAR

On October 18, 2010, NU and NSTAR announced that each company's Board of Trustees unanimously approved a merger agreement (the "agreement"), under which NSTAR will become a direct wholly owned subsidiary of NU. The transaction is structured as a merger of equals in a tax-free exchange of shares. Under the terms of the agreement, NSTAR shareholders will receive 1.312 NU common shares for each NSTAR common share that they own (the "exchange ratio"). Shareholders of both NU and NSTAR approved the pending merger at special meetings of shareholders held on March 4, 2011. Post-transaction, NU will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire.

The exchange ratio was structured to result in a no premium merger based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Based on the number of NU common shares and NSTAR common shares estimated to be outstanding immediately prior to the closing of the merger, upon such closing, NU will be owned approximately 56 percent by NU shareholders and approximately 44 percent by former NSTAR shareholders. It is anticipated that NU will issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Subject to the conditions in the agreement, NU s first quarterly dividend per common share paid after the closing of the merger will be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

At closing, NU will acquire NSTAR and, in accordance with accounting standards for business combinations, account for the transaction as an acquisition of NSTAR by NU.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU has received regulatory approvals from the FCC, the FERC and the Maine Public Utilities Commission and the applicable Hart-Scott-Rodino waiting period has expired. The PURA and the NHPUC have issued decisions stating they do not have jurisdiction over the merger. NU is awaiting approval from the DPU and the Nuclear Regulatory Commission.

B.

Presentation

Pursuant to the rules and regulations of the SEC, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. 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 2011 combined Quarterly Reports on Form 10-Q, and the 2010 combined Annual Report on Form 10-K of NU, CL&P, PSNH, and WMECO, which was filed with the SEC (NU 2010 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 positions as of September 30, 2011 and December 31, 2010, the results of operations for the three and nine months ended September 30, 2011 and 2010, and cash flows for the nine months ended September 30, 2011 and 2010. The results of operations for the three months ended September 30, 2011 and 2010, and the results of operations and cash flows for the nine months ended September 30, 2011 and 2010, 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 GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

During 2011, NU, CL&P, PSNH and WMECO adjusted the presentation of Regulatory Assets and Liabilities to reflect the current portions, and related deferred tax amounts, as current assets and liabilities on the unaudited condensed consolidated balance sheets. Amounts as of December 31, 2010 have been reclassified to conform to the September 30, 2011 presentation. For additional information, see Note 2, "Regulatory Accounting," to the unaudited condensed consolidated financial statements.

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

NU evaluates events and transactions that occur after the balance sheet date but before financial statements are issued and recognizes in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed as of the balance sheet date and discloses but does not recognize in the financial statements subsequent events that provide evidence about the conditions that arose after the balance sheet date but before the financial statements are issued. See Note 16, "Subsequent Events," for further information.

C.

Accounting Standards Issued But Not Yet Adopted

In May 2011, the FASB and IASB issued a final Accounting Standards Update (ASU) on fair value measurement, effective January 1, 2012, that is not expected to have a material impact on NU s financial position, results of operations or cash flows, but will require additional financial statement disclosures related to fair value measurements.

In September 2011, the FASB issued a final ASU on testing goodwill for impairment, effective January 1, 2012 with early adoption permitted. The standard provides the option to perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying value; if so, quantitative testing is required. The standard does not change existing guidance relating to when an entity should test goodwill for impairment or the methodology to be utilized in performing quantitative testing. The standard will not have an impact on NU s financial position, results of operations or cash flows.

D.

Restricted Cash

As of September 30, 2011, NU, CL&P, and PSNH had $16.5 million, $8 million, and $7 million, respectively, of restricted cash, primarily relating to amounts held in escrow related to property damage at CL&P and insurance proceeds on bondable property at PSNH, which were included in Prepayments and Other Current Assets on the accompanying unaudited condensed consolidated balance sheets. NU, CL&P, and PSNH had no restricted cash as of December 31, 2010.

E.

Provision for Uncollectible Accounts

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

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

(Millions of Dollars)	**As of September 30, 2011**		**As of December 31, 2010**	
NU	$	34.0	$	39.8
CL&P		13.9		17.2
PSNH		7.3		6.8
WMECO		4.3		6.0

F.

Fair Value Measurements

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

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

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

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

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

Determination of Fair Value: The valuation techniques and inputs used in NU's fair value measurements are described in Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the unaudited condensed consolidated financial statements.

G.

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.

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
(Millions of Dollars, except percentages)	**NU**	**NU**	**NU**	**NU**
AFUDC:				
Borrowed Funds	$ 3.3	$ 2.8	$ 9.8	$ 6.9
Equity Funds	6.6	4.6	18.4	11.6
Total	$ 9.9	$ 7.4	$ 28.2	$ 18.5
Average AFUDC Rate	7.0%	7.3%	7.3%	7.1%

	For the Three Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
AFUDC:						
Borrowed Funds	$ 0.8	$ 2.1	$ 0.1	$ 0.7	$ 1.8	$ 0.1
Equity Funds	1.4	4.2	0.2	1.2	2.9	0.2
Total	$ 2.2	$ 6.3	$ 0.3	$ 1.9	$ 4.7	$ 0.3
Average AFUDC Rate	8.0%	6.7%	6.4%	8.1%	6.9%	8.3%

	For the Nine Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars, except percentages)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
AFUDC:						
Borrowed Funds	$ 2.3	$ 6.5	$ 0.3	$ 2.0	$ 4.4	$ 0.2
Equity Funds	4.1	12.0	0.5	3.7	7.1	0.4
Total	$ 6.4	$ 18.5	$ 0.8	$ 5.7	$ 11.5	$ 0.6
Average AFUDC Rate	8.3%	7.0%	6.7%	8.4%	6.7%	5.8%

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

AFUDC was recorded on 100 percent of CL&P's and WMECO's CWIP for their NEEWS projects through May 31, 2011, all of which was reserved as a regulatory liability to reflect rate base recovery for 100 percent of the CWIP as a result of FERC-approved transmission incentives. Effective June 1, 2011, FERC approved changes to the ISO-NE Tariff in order to include 100 percent of the NEEWS CWIP in regional rate base. As a result, CL&P and WMECO will no longer record AFUDC on NEEWS CWIP.

H.

Other Income, Net

The other income/(loss) items included within Other Income, Net on the accompanying unaudited condensed consolidated statements of income primarily consist of investment income/(loss), interest income, AFUDC related to equity funds and equity in earnings, which relates to the Company's investments, including investments of CL&P, PSNH and WMECO, in the Yankee Companies and NU's investment in two regional transmission companies.

I.

Other Taxes

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

	For the Three Months Ended		For the Nine Months Ended	
(Millions of Dollars)	**September 30, 2011**	**September 30, 2010**	**September 30, 2011**	**September 30, 2010**
NU	$ 35.0	$ 37.0	$ 105.8	$ 109.0
CL&P	33.0	35.1	93.2	97.3

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.

J. Supplemental Cash Flow Information

Non-cash investing activities include capital expenditures incurred but not yet paid as follows:

(Millions of Dollars)	**As of September 30, 2011**	**As of December 31, 2010**
NU	$ 121.7	$ 127.9
CL&P	22.1	46.2
PSNH	32.4	35.8
WMECO	45.8	21.2

Short-term borrowings of NU, including CL&P, PSNH, and WMECO, have original maturities of three months or less. Accordingly, borrowings and repayments are shown net on the unaudited condensed consolidated statements of cash flows.

2.

REGULATORY ACCOUNTING

The Regulated companies continue to be rate-regulated on a cost-of-service basis, therefore, the accounting policies of the Regulated companies conform to GAAP applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process.

Management believes it is probable that the Regulated companies will recover their respective investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning a return, except for the majority of deferred benefit cost assets, regulatory assets offsetting derivative liabilities, securitized regulatory assets, income tax regulatory assets and certain storm costs, all of which are not in rate base.

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

	As of September 30, 2011	**As of December 31, 2010**
(Millions of Dollars)	**NU**	**NU**
Deferred Benefit Costs	$ 1,006.6	$ 1,094.2
Regulatory Assets Offsetting Derivative Liabilities	895.3	859.7
Securitized Assets	119.7	171.7
Income Taxes, Net	417.1	401.5
Unrecovered Contractual Obligations	106.9	123.2
Regulatory Tracker Deferrals	30.4	70.3
Storm Cost Deferrals	171.7	60.1
Asset Retirement Obligations	47.7	45.3
Losses on Reacquired Debt	21.8	21.5

Deferred Environmental Remediation Costs		39.0		36.8
Deferred Operation and Maintenance Costs		5.9		29.5
Other Regulatory Assets		79.5		81.5
Total Regulatory Assets	$	2,941.6	$	2,995.3
Less: Current Portion	$	235.5	$	238.7
Total Long-Term Regulatory Assets	$	2,706.1	$	2,756.6

	As of September 30, 2011			As of December 31, 2010		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Deferred Benefit Costs Regulatory Assets	$ 432.9	$ 141.4	$ 88.6	$ 471.8	$ 152.6	$ 96.0
Offsetting Derivative Liabilities	891.6	3.3	-	846.2	12.8	-
Securitized Assets	-	90.1	29.6	-	129.8	41.9
Income Taxes, Net	333.5	37.6	16.9	328.9	31.4	16.8
Unrecovered Contractual Obligations	85.4	-	21.5	97.9	-	25.3
Regulatory Tracker Deferrals	7.1	2.3	15.9	35.5	14.7	15.2
Storm Cost Deferrals	104.9	46.2	20.6	4.0	40.7	15.4
Asset Retirement Obligations	26.6	15.1	3.2	24.9	14.7	3.0
Losses on Reacquired Debt	10.9	9.2	0.3	11.2	8.4	0.4
Deferred Environmental Remediation Costs	-	9.7	-	-	9.7	-
Deferred Operation and Maintenance Costs	5.9	-	-	29.5	-	-
Other Regulatory Assets	26.6	23.9	9.9	29.0	19.6	13.1
Total Regulatory Assets	$ 1,925.4	$ 378.8	$ 206.5	$ 1,878.9	$ 434.4	$ 227.1
Less: Current Portion	$ 170.3	$ 20.7	$ 24.2	$ 157.5	$ 39.2	$ 19.5
Total Long-Term Regulatory Assets	$ 1,755.1	$ 358.1	$ 182.3	$ 1,721.4	$ 395.2	$ 207.6

Additionally, the Regulated companies had $11.9 million ($0.9 million for CL&P, $6.3 million for PSNH and $1.1 million for WMECO) and $37.5 million ($0.6 million for CL&P, $26.5 million for PSNH and $1.9 million for WMECO) of regulatory costs as of September 30, 2011 and December 31, 2010, respectively, which were included in Other Long-Term Assets 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 probable of recovery in future cost-of-service regulated rates.

Major Storms: On August 28, 2011, Tropical Storm Irene caused extensive damage to the NU overhead electric distribution system, particularly at CL&P. The estimated cost of restoration that was deferred for future recovery from customers and recorded as a regulatory asset as of September 30, 2011 for CL&P totaled approximately $92 million. The estimated cost of restoration is subject to change as additional cost information becomes available. CL&P is currently allowed to collect from customers $3 million per year for

major storm costs. CL&P will seek recovery of the Tropical Storm Irene deferred storm costs through the appropriate regulatory recovery process. Management believes CL&P will be allowed to recover these deferred storm costs.

On October 29, 2011, a snowstorm delivered high winds and heavy snowfall across the NU service territory, causing significant damage to NU s distribution and transmission systems. Approximately 1.2 million NU customers were without power at the peak of the outages, with approximately 830,000 of those customers in Connecticut, approximately 240,000 of those customers in New Hampshire, and approximately 140,000 of those customers in Massachusetts. In terms of customer outages, this was the largest in CL&P s history, surpassing Tropical Storm Irene, the third largest in PSNH s history and the largest in WMECO's history. As a result of the magnitude of the damage, management anticipates the costs of restoring service will approximate or exceed those of Tropical Storm Irene. As management expects such costs to meet the criteria for recovery in Connecticut, Massachusetts, and New Hampshire, CL&P, WMECO and PSNH will seek recovery of these anticipated deferred storm costs through their applicable regulatory recovery process and as a result, these respective costs will be deferred as either a long-term regulatory asset or long-term other deferred debit at CL&P, PSNH and WMECO.

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

	As of September 30, 2011		As of December 31, 2010	
(Millions of Dollars)	NU		NU	
Cost of Removal	$	180.7	$	194.8
Regulatory Liabilities Offsetting Derivative Assets		-		38.1
Regulatory Tracker Deferrals		152.4		95.1
AFUDC Transmission Incentive		67.2		62.1
Pension Liability - Yankee Gas Acquisition		10.6		12.5
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations		14.6		14.6
Wholesale Transmission Overcollections		10.5		13.7
Other Regulatory Liabilities		14.8		8.2
Total Regulatory Liabilities	$	450.8	$	439.1
Less: Current Portion	$	174.6	$	99.4
Total Long-Term Regulatory Liabilities	$	276.2	$	339.7

	As of September 30, 2011						As of December 31, 2010					
(Millions of Dollars)	CL&P		PSNH		WMECO		CL&P		PSNH		WMECO	
Cost of Removal	$	69.6	$	55.2	$	7.6	$	78.6	$	57.3	$	9.5
Regulatory Liabilities Offsetting Derivative Assets		-		-		-		38.1		-		-
Regulatory Tracker Deferrals		107.6		22.5		20.9		79.4		6.6		4.8
AFUDC Transmission Incentive		57.9		-		9.3		56.5		-		5.6
Overrecovered Spent Nuclear Fuel Costs and Contractual Obligations		14.6		-		-		14.6		-		-
Wholesale Transmission Overcollections		2.0		-		8.5		13.7		-		-
		-		-		1.3		-		-		2.0

WMECO Provision For Rate Refunds												
Other Regulatory Liabilities		6.1		4.5		2.0		1.2		3.1		1.1
Total Regulatory Liabilities	$	257.8	$	82.2	$	49.6	$	282.1	$	67.0	$	23.0
Less: Current Portion	$	111.9	$	25.6	$	32.6	$	75.7	$	8.4	$	8.0
Total Long-Term Regulatory Liabilities	$	145.9	$	56.6	$	17.0	$	206.4	$	58.6	$	15.0

21

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

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

	As of September 30, 2011	As of December 31, 2010
(Millions of Dollars)	NU	NU
Distribution - Electric	$ 6,427.0	$ 6,197.2
Distribution - Natural Gas	1,194.0	1,126.6
Transmission	3,410.2	3,378.0
Generation	1,043.9	697.1
Electric and Natural Gas Utility	12,075.1	11,398.9
Other [1]	306.0	305.5
Total Property, Plant and Equipment, Gross	12,381.1	11,704.4
Less: Accumulated Depreciation		
Electric and Natural Gas Utility	(2,986.0)	(2,862.3)
Other	(122.3)	(119.9)
Total Accumulated Depreciation	(3,108.3)	(2,982.2)
Property, Plant and Equipment, Net	9,272.8	8,722.2
Construction Work in Progress	823.3	845.5
Total Property, Plant and Equipment, Net	$ 10,096.1	$ 9,567.7

(1)

These assets are primarily owned by RRR ($163.2 million and $166 million) and NUSCO ($130.9 million and $126.6 million) as of September 30, 2011 and December 31, 2010, respectively, and are mainly comprised of building improvements at RRR and software and equipment at NUSCO.

	As of September 30, 2011			As of December 31, 2010		
(Millions of Dollars)	CL&P	PSNH	WMECO	CL&P	PSNH	WMECO
Distribution	$ 4,354.2	$ 1,417.1	$ 690.0	$ 4,180.7	$ 1,375.4	$ 673.7
Transmission	2,650.4	499.7	260.1	2,668.4	476.1	233.5
Generation	-	1,034.5	9.4	-	687.7	9.4
Total Property, Plant and Equipment, Gross	7,004.6	2,951.3	959.5	6,849.1	2,539.2	916.6
Less: Accumulated Depreciation	(1,570.2)	(876.4)	(238.0)	(1,508.7)	(837.3)	(228.5)
Property, Plant and Equipment, Net	5,434.4	2,074.9	721.5	5,340.4	1,701.9	688.1
Construction Work in Progress	294.9	106.3	264.8	246.1	351.4	129.0
Total Property, Plant and Equipment, Net	$ 5,729.3	$ 2,181.2	$ 986.3	$ 5,586.5	$ 2,053.3	$ 817.1

On May 31, 2011, CL&P completed the sale of a segment of high voltage transmission lines in the town of Wallingford, Connecticut. The net book value of the assets sold was $42.5 million. CL&P will operate and maintain the lines under an operations and maintenance agreement.

4.

DERIVATIVE INSTRUMENTS

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

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

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

CL&P mitigates the risks associated with the price volatility of energy and energy-related products through the use of SS or LRS contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to three years and are accounted for as normal. CL&P has entered into derivatives, including FTR contracts, to manage the risk of congestion costs associated with its SS and LRS contracts. As required by regulation, CL&P has also entered into derivative and nonderivative contracts for the purchase of energy and energy-related products and contracts related to capacity. While the risks managed by these contracts are regional congestion costs and capacity price risks that are not specific to CL&P, Connecticut's electric distribution companies, including CL&P, are required to enter into these contracts. The costs or benefits from these contracts are recoverable from or refundable to CL&P's customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying unaudited condensed consolidated balance sheets.

22

WMECO mitigates the risks associated with the volatility of the prices of energy and energy-related products in procuring energy supply for its customers through the use of basic service contracts, which fix the price of electricity purchased for customers for periods of time ranging from three months to one year 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 and FTRs. PSNH enters into these contracts in order to stabilize electricity prices for customers by mitigating uncertainties associated with the New England spot market. The costs or benefits from these contracts are recoverable from or refundable to PSNH's customers, and, therefore changes in fair value are recorded as Regulatory Assets and Regulatory Liabilities on the accompanying unaudited condensed consolidated balance sheets.

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

NU, through Select Energy, has one remaining fixed price forward sales contract to serve electrical load that is part of its remaining unregulated wholesale energy marketing portfolio. NU mitigates the price risk associated with this contract through the use of forward purchase contracts. The contracts are accounted for at fair value, and changes in their fair values are recorded in Fuel, Purchased and Net Interchange Power on the accompanying unaudited condensed consolidated statements of income.

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

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, in the accompanying unaudited condensed consolidated balance sheets. Cash collateral posted or collected under master netting agreements is recorded as an offset to the derivative asset or liability. 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, 2011
Derivatives Not Designated as Hedges	

(Millions of Dollars)	Commodity and Capacity Contracts Required by Regulation	Commodity Supply and Price Risk Management	Hedging Instruments	Collateral and Netting (1)	Net Amount Recorded as Derivative Asset/(Liability) (2)
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 5.0	$ -	$ 5.0
Level 3:					
CL&P	17.2	0.5	-	(11.2)	6.5
Other	-	2.7	-	-	2.7
Total Current Derivative Assets	$ 17.2	$ 3.2	$ 5.0	$ (11.2)	$ 14.2
Long-Term Derivative Assets:					
Level 3:					
CL&P	$ 165.6	$ -	$ -	$ (77.5)	$ 88.1
Other	-	3.3	-	-	3.3
Total Long-Term Derivative Assets	$ 165.6	$ 3.3	$ -	$ (77.5)	$ 91.4
Current Derivative Liabilities:					
Level 2:					
PSNH	$ -	$ (3.3)	$ -	$ -	$ (3.3)
Level 3:					
CL&P	(93.9)	(0.1)	-	-	(94.0)
Other	-	(13.6)		0.2	(13.4)
Total Current Derivative Liabilities	$ (93.9)	$ (17.0)	$ -	$ 0.2	$ (110.7)
Long-Term Derivative Liabilities:					
Level 3:					
CL&P	$ (891.7)	$ -	$ -	$ -	$ (891.7)
Other	-	(17.8)	-	0.2	(17.6)
Total Long-Term Derivative Liabilities	$ (891.7)	$ (17.8)	$ -	$ 0.2	$ (909.3)

	As of December 31, 2010				
	Derivatives Not Designated as Hedges				
(Millions of Dollars)	Commodity and Capacity Contracts Required by Regulation	Commodity Supply and Price Risk Management	Hedging Instruments	Collateral and Netting (1)	Net Amount Recorded as Derivative Asset/(Liability) (2)
Current Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 7.7	$ -	$ 7.7
Level 3:					
CL&P	5.8	2.1	-	-	7.9
Other	-	1.7	-	-	1.7
Total Current Derivative Assets	$ 5.8	$ 3.8	$ 7.7	$ -	$ 17.3
Long-Term Derivative Assets:					
Level 2:					
Other	$ -	$ -	$ 4.1	$ -	$ 4.1
Level 3:					
CL&P	195.9	-	-	(80.0)	115.9
Other	-	3.2	-	-	3.2
Total Long-Term Derivative Assets	$ 195.9	$ 3.2	$ 4.1	$ (80.0)	$ 123.2
Current Derivative Liabilities:					
Level 2:					
PSNH	$ -	$ (12.8)	$ -	$ -	$ (12.8)
Level 3:					
CL&P	(54.3)	(0.2)	-	7.7	(46.8)
Other	-	(12.4)	-	0.5	(11.9)
Total Current Derivative Liabilities	$ (54.3)	$ (25.4)	$ -	$ 8.2	$ (71.5)
Long-Term Derivative Liabilities:					
Level 3:					
CL&P	$ (883.1)	$ -	$ -	$ -	$ (883.1)
Other	-	(26.8)	-	0.2	(26.6)
Total Long-Term Derivative Liabilities	$ (883.1)	$ (26.8)	$ -	$ 0.2	$ (909.7)

(1)

Amounts represent cash collateral posted under master netting agreements and the netting of derivative assets and liabilities. See "Credit Risk" below for discussion of cash collateral posted under master netting agreements.

(2)

Current derivative assets are included in Prepayments and Other Current Assets on the accompanying unaudited condensed consolidated balance sheets.

For further information on the fair value of derivative contracts, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," to the unaudited condensed consolidated financial statements.

Derivatives not designated as hedges

CL&P commodity and capacity contracts required by regulation: CL&P has capacity related contracts with generation facilities. These contracts and similar UI contracts, have an expected capacity of 787 MW. CL&P has a sharing agreement with UI, with 80 percent allocated to CL&P and 20 percent allocated to UI. The capacity contracts have terms up to 15 years and obligate the utilities to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the forward capacity market price received in the ISO-NE capacity markets. The largest of these generation facilities achieved commercial operation in July 2011. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

Commodity supply and price risk management: As of September 30, 2011 and December 31, 2010, CL&P had 0.5 million and 1.8 million MWh, respectively, remaining under FTRs that extend through December 2011 and require monthly payments or receipts.

PSNH has electricity procurement contracts with delivery dates through 2011 to purchase an aggregate amount of 0.1 million and 0.4 million MWh of power as of September 30, 2011 and December 31, 2010, respectively. In addition, PSNH has 0.1 million and 0.3 million MWh remaining under FTRs as of September 30, 2011 and December 31, 2010, respectively, that extend through December 2011 and require monthly payments or receipts.

As of September 30, 2011 and December 31, 2010, NU had approximately 0.1 million and 0.3 million MWh, respectively, of supply volumes remaining in its unregulated wholesale portfolio when expected sales are compared with contracted supply, both of which extend through 2013.

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

(Millions of Dollars)	Location of Gain or Loss Recognized on Derivative	Amount of Gain/(Loss) Recognized on Derivative Instrument			
		For the Three Months Ended		For the Nine Months Ended	
		September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
NU					
Commodity and Capacity Contracts					
Required by Regulation	Regulatory Assets/Liabilities	$ (47.3)	$ (49.8)	$ (90.4)	$ (141.6)
Commodity Supply and Price Risk					
Management	Regulatory Assets/Liabilities	(0.4)	(2.9)	(2.4)	(22.7)
Commodity Supply and Price Risk	Fuel, Purchased and Net				
Management	Interchange Power	0.3	1.2	1.0	1.7
CL&P					
Commodity and Capacity Contracts					
Required by Regulation	Regulatory Assets/Liabilities	(47.3)	(49.8)	(90.4)	(141.6)
Commodity Supply and Price Risk					
Management	Regulatory Assets/Liabilities	(0.6)	(0.8)	(2.5)	(4.4)
PSNH					
Commodity Supply and Price Risk					
Management	Regulatory Assets/Liabilities	0.2	(2.1)	0.2	(17.8)

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

Hedging instruments

<u>Fair Value Hedge</u>: To manage the balance of its fixed and floating rate debt, NU parent has a fixed to floating interest rate swap on its $263 million, fixed rate senior notes maturing on April 1, 2012. This interest rate swap qualifies and was designated as a fair value hedge and requires semi-annual cash settlements. The changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in Interest Expense on the accompanying unaudited condensed consolidated statements of income. There was no ineffectiveness recorded for the three and nine months ended September 30, 2011 and 2010. The cumulative changes in fair values of the swap and the Long-Term Debt are recorded as a Derivative Asset/Liability and an adjustment to Long-Term Debt. Interest receivable is recorded as a reduction of Interest Expense and is included in Prepayments and Other Current Assets.

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

	For the Three Months Ended							
	September 30, 2011				**September 30, 2010**			
(Millions of Dollars)		**Swap**		**Hedged Debt**		**Swap**		**Hedged Debt**
Changes in Fair Value	$	(0.2)	$	0.2	$	2.8	$	(2.8)
Interest Recorded in Net Income		-		2.5		-		2.9

	For the Nine Months Ended							
	September 30, 2011				**September 30, 2010**			
(Millions of Dollars)		**Swap**		**Hedged Debt**		**Swap**		**Hedged Debt**
Changes in Fair Value	$	1.1	$	(1.1)	$	10.2	$	(10.2)
Interest Recorded in Net Income		-		7.9		-		8.2

<u>Cash Flow Hedges</u>: In 2011, PSNH and WMECO entered into cash flow hedges related to a portion of their respective planned debt issuances. PSNH entered into three forward starting swaps to fix the U.S. dollar LIBOR swap rate of 3.73 percent on $80 million of a planned $160 million long-term debt issuance, 2.79 percent on the remaining $80 million of the planned $160 million long-term debt issuance and 3.60 percent on $120 million of planned refinancing of PCRBs. In May 2011, PSNH settled the swap associated with the $120 million refinancing of PCRBs and a $2.9 million pre-tax reduction in AOCI will be amortized over the life of the debt. In September 2011, PSNH settled the two remaining swaps associated with the $160 million long-term debt issuance and a $15.3 million pre-tax reduction in AOCI will be amortized over the life of the debt. WMECO entered into a forward starting swap to fix the U.S. dollar LIBOR swap rate of 3.75 percent associated with $50 million of a planned $100 million long-term debt issuance. In September 2011, WMECO settled the swap and a $6.9 million pre-tax reduction in AOCI will be amortized over the life of the debt. 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 AOCI. When a cash flow hedge is settled, the settlement amount is recorded in AOCI and is amortized into Net Income over the term of the underlying debt instrument. Cash flow hedges also 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.

The pre-tax impact of cash flow hedging instruments on AOCI is as follows:

	Gains/(Losses) Recognized on Derivative Instruments		Gains/(Losses) Reclassified from AOCI into Interest Expense For the Three Months Ended		Gains/(Losses) Reclassified from AOCI into Interest Expense For the Nine Months Ended	
(Millions of Dollars)	**For the Three Months Ended September 30, 2011**	**For the Nine Months Ended September 30, 2011**	**September 30, 2011**	**September 30, 2010**	**September 30, 2011**	**September 30, 2010**
NU	$ (18.3)	$ (25.1)	$ (0.4)	$ (0.1)	$ (0.6)	$ (0.3)
CL&P	-	-	(0.2)	(0.2)	(0.6)	(0.6)
PSNH	(12.9)	(18.2)	(0.2)	-	(0.3)	(0.1)
WMECO	(5.4)	(6.9)	-	-	-	0.1

For further information, see Note 10, "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 and NU's sourcing contracts related to the remaining wholesale marketing contract, contain credit risk contingent features. These features require these companies to maintain investment grade credit ratings from the major rating agencies and to post cash or standby LOCs as collateral for contracts in a net liability position over specified credit limits. NU parent provides standby LOCs under its revolving credit agreement for NU subsidiaries to post with counterparties. The following summarizes the fair value of derivative contracts that are in a liability position and subject to credit risk contingent features, the fair value of cash collateral and standby LOCs posted with counterparties and the additional collateral in the form of LOCs that would be required to be posted by NU or PSNH if the respective unsecured debt credit ratings of NU parent or PSNH were downgraded to below investment grade as of September 30, 2011 and December 31, 2010:

	As of September 30, 2011			
(Millions of Dollars)	**Fair Value Subject to Credit Risk Contingent Features**	**Cash Collateral Posted**	**Standby LOCs Posted**	**Additional Standby LOCs Required if Downgraded Below Investment Grade**
NU	$ (22.1)	$ -	$ 6.0	$ 19.1
PSNH	(3.3)	-	6.0	0.5

As of December 31, 2010

	Fair Value Subject	**Additional Standby LOCs Required if**

(Millions of Dollars)	to Credit Risk Contingent Features	Cash Collateral Posted	Standby LOCs Posted	Downgraded Below Investment Grade
NU	$ (30.9)	$ 0.5	$ 24.0	$ 18.5
PSNH	(12.8)	-	24.0	-

Fair Value Measurements of Derivative Instruments:

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

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

The remaining contracts included in Commodity Supply and Price Risk Management and classified as Level 3 in the tables below are valued using broker quotes based on prices in an inactive market.

Valuations using significant unobservable inputs: The following tables present changes for the three and nine months ended September 30, 2011 and 2010 in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis. The Company classifies assets and liabilities in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model. In addition to these unobservable inputs, the valuation models for Level 3 assets and liabilities typically also rely on a number of inputs that are observable either directly or indirectly. Thus the gains and losses presented below include changes in fair value that are attributable to both observable and unobservable inputs. There were no transfers into or out of Level 3 assets and liabilities for the three and nine months ended September 30, 2011 and 2010.

	For the Three Months Ended September 30, 2011 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
<u>Derivatives, Net:</u>			
Fair Value as of Beginning of Period	$ (859.6)	$ (26.6)	$ (886.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income(1)	-	0.3	0.3
Regulatory Assets/Liabilities	(47.3)	(0.6)	(47.9)
Settlements	15.4	2.3	17.7
Fair Value as of End of Period	$ (891.5)	$ (24.6)	$ (916.1)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.1	$ 0.1

	For the Nine Months Ended September 30, 2011 NU		
(Millions of Dollars)	**Commodity and Capacity Contracts Required By Regulation**	**Commodity Supply and Price Risk Management**	**Total Level 3**
<u>Derivatives, Net:</u>			
Fair Value as of Beginning of Period	$ (808.0)	$ (32.2)	$ (840.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income(1)	-	1.0	1.0
Regulatory Assets/Liabilities	(90.4)	(2.6)	(93.0)
Settlements	6.9	9.2	16.1
Fair Value as of End of Period	$ (891.5)	$ (24.6)	$ (916.1)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.7	$ 0.7

	For the Three Months Ended September 30, 2011 CL&P	
	Commodity and Capacity Contracts Required By	**Commodity Supply and Price Risk**

(Millions of Dollars)	Regulation	Management	Total Level 3
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (859.6)	$ 0.9	$ (858.7)
Net Realized/Unrealized Losses Included in:			
Regulatory Assets/Liabilities	(47.3)	(0.6)	(47.9)
Settlements	15.4	0.1	15.5
Fair Value as of End of Period	$ (891.5)	$ 0.4	$ (891.1)

	For the Nine Months Ended September 30, 2011 CL&P		
(Millions of Dollars)	Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (808.0)	$ 1.9	$ (806.1)
Net Realized/Unrealized Losses Included in:			
Regulatory Assets/Liabilities	(90.4)	(2.5)	(92.9)
Settlements	6.9	1.0	7.9
Fair Value as of End of Period	$ (891.5)	$ 0.4	$ (891.1)

27

(Millions of Dollars)	For the Three Months Ended September 30, 2010 NU Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (818.3)	$ (38.5)	$ (856.8)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income [(1)]	-	1.2	1.2
Regulatory Assets/Liabilities	(49.8)	(0.9)	(50.7)
Settlements	(5.7)	2.2	(3.5)
Fair Value as of End of Period	$ (873.8)	$ (36.0)	$ (909.8)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 1.0	$ 1.0

(Millions of Dollars)	For the Nine Months Ended September 30, 2010 NU Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (720.3)	$ (40.9)	$ (761.2)
Net Realized/Unrealized Gains/(Losses) Included in:			
Net Income[(1)]	-	1.7	1.7
Regulatory Assets/Liabilities	(141.6)	(5.1)	(146.7)
Settlements	(11.9)	8.3	(3.6)
Fair Value as of End of Period	$ (873.8)	$ (36.0)	$ (909.8)
Period Change in Unrealized Gains Included in			
Net Income Relating to Items Held as of End of Period	$ -	$ 0.9	$ 0.9

(Millions of Dollars)	For the Three Months Ended September 30, 2010 CL&P Commodity and Capacity Contracts Required By Regulation	Commodity Supply and Price Risk Management	Total Level 3
Derivatives, Net:			
Fair Value as of Beginning of Period	$ (818.3)	$ 1.8	$ (816.5)
Net Realized/Unrealized Losses Included in:			
Regulatory Assets/Liabilities	(49.8)	(0.8)	(50.6)

Settlements		(5.7)		(0.2)		(5.9)
Fair Value as of End of Period	$	(873.8)	$	0.8	$	(873.0)

	For the Nine Months Ended September 30, 2010 CL&P					
(Millions of Dollars)		**Commodity and Capacity Contracts Required By Regulation**		**Commodity Supply and Price Risk Management**		**Total Level 3**
Derivatives, Net:						
Fair Value as of Beginning of Period	$	(720.3)	$	4.5	$	(715.8)
Net Realized/Unrealized Losses Included in:						
Regulatory Assets/Liabilities		(141.6)		(4.4)		(146.0)
Settlements		(11.9)		0.7		(11.2)
Fair Value as of End of Period	$	(873.8)	$	0.8	$	(873.0)

(1)

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

5.

MARKETABLE SECURITIES (NU, WMECO)

The Company elects to record mutual funds purchased by the NU supplemental benefit trust at fair value. As such, any change in fair value of these purchased equity securities is reflected in Net Income. These equity securities, classified as Level 1 in the fair value hierarchy, totaled $37.3 million and $42.2 million as of September 30, 2011 and December 31, 2010, respectively, and are included in current Marketable Securities. Losses on these securities of $7.1 million and $4.9 million for the three and nine months ended September 30, 2011 and gains of $5.7 million and $3.2 million for the three and nine months ended September 30, 2010, 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 of NU's available-for-sale securities held in the NU supplemental benefit trust and WMECO's spent nuclear fuel trust. These securities are recorded at fair value and included in current and long-term Marketable Securities on the accompanying unaudited condensed consolidated balance sheets.

	As of September 30, 2011			
(Millions of Dollars)	**Amortized Cost**	**Pre-Tax Unrealized Gains[(1)]**	**Pre-Tax Unrealized Losses[(1)]**	**Fair Value**
NU	$ 87.8	$ 1.9	$ (0.3)	$ 89.4
WMECO	57.3	-	(0.2)	57.1

	As of December 31, 2010			
(Millions of Dollars)	**Amortized Cost**	**Pre-Tax Unrealized Gains[(1)]**	**Pre-Tax Unrealized Losses[(1)]**	**Fair Value**
NU	$ 86.3	$ 1.3	$ (0.3)	$ 87.3
WMECO	57.2	-	(0.1)	57.1

(1)

Unrealized gains and losses on debt securities for the NU supplemental benefit trust and WMECO spent nuclear fuel trust are recorded in AOCI and Other Long-Term Assets, respectively, on the accompanying unaudited condensed consolidated balance sheets.

Unrealized Losses and Other-than-Temporary Impairment: There have been no significant unrealized losses, other-than-temporary impairments or credit losses for the NU supplemental benefit trust or WMECO spent nuclear fuel trust. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset backed debt securities, underlying collateral and expected future cash flows are also evaluated.

Realized gains and losses: Realized gains and losses on available-for-sale-securities are recorded in Other Income, Net for the NU supplemental benefit trust and in Other Long-Term Assets for the WMECO spent nuclear fuel trust. NU utilizes the specific identification basis method for the NU supplemental benefit trust securities and the average cost basis method for the WMECO spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Contractual Maturities: As of September 30, 2011, the contractual maturities of available-for-sale debt securities are as follows:

	NU		WMECO	
(Millions of Dollars)	Amortized Cost	Fair Value	Amortized Cost	Fair Value
Less than one year	$ 37.2	$ 37.2	$ 34.9	$ 34.9
One to five years	16.1	16.2	10.7	10.6
Six to ten years	10.7	11.1	6.7	6.7
Greater than ten years	23.8	24.9	5.0	4.9
Total Debt Securities	$ 87.8	$ 89.4	$ 57.3	$ 57.1

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

	NU		WMECO	
(Millions of Dollars)	As of September 30, 2011	As of December 31, 2010	As of September 30, 2011	As of December 31, 2010
Level 1:				
Mutual Funds	$ 37.3	$ 42.2	$ -	$ -
Money Market Funds	1.3	1.8	0.4	0.3
Total Level 1	$ 38.6	$ 44.0	$ 0.4	$ 0.3
Level 2:				
U.S. Government Issued Debt Securities (Agency and Treasury)	2.9	17.8	-	6.0
Corporate Debt Securities	17.1	22.5	8.5	15.6
Asset Backed Debt Securities	27.4	11.6	8.5	4.7
Municipal Bonds	16.4	16.1	15.7	15.4
Other Fixed Income Securities	24.3	17.5	24.0	15.1
Total Level 2	$ 88.1	$ 85.5	$ 56.7	$ 56.8
Total Marketable Securities	$ 126.7	$ 129.5	$ 57.1	$ 57.1

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instrument and also incorporating yield curves, credit spreads and specific bond terms and conditions. Municipal

bonds are valued using a market approach that incorporates reported trades and benchmark yields. Asset backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and maturity dates and tranche information. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6.

LONG-TERM DEBT (PSNH, WMECO)

On May 26, 2011, PSNH issued $122 million of Series Q first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021. The proceeds of these bonds were used to redeem two series of tax-exempt PCRBs. The indenture under which the bonds were issued requires PSNH to comply with certain covenants as are customarily included in such indentures.

On September 13, 2011, PSNH issued $160 million of Series R first mortgage bonds with a coupon rate of 3.20 percent and a maturity date of September 1, 2021. The proceeds, net of issuance expenses, were used to repay short-term borrowings previously incurred in the ordinary course of business and for general capital purposes. The indenture under which the bonds were issued requires PSNH to comply with certain covenants as are customarily included in such indentures.

On September 16, 2011, WMECO issued $100 million of Series F unsecured senior notes with a coupon rate of 3.50 percent and a maturity date of September 15, 2021. The proceeds, net of issuance expenses, were used to repay short-term borrowings previously incurred in the ordinary course of business. The indenture under which the notes were issued requires WMECO to comply with certain covenants as are customarily included in such indentures.

NU, including CL&P, PSNH and WMECO, was in compliance with all its debt covenants as of September 30, 2011.

7.

PENSION BENEFITS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

NUSCO sponsors a Pension Plan, which is subject to the provisions of ERISA, as amended by the PPA of 2006. 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). In addition, NU maintains a SERP, which provides benefits to eligible participants who are officers of NU. This plan provides benefits that would have been provided to these employees under the Pension Plan if certain Internal Revenue Code limitations were not imposed. On behalf of NU's retirees, NUSCO also sponsors plans that provide certain retiree health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan.

The components of net periodic benefit expense for the Pension Plan (including the SERP) and PBOP Plan and intercompany allocations not included in the net periodic benefit expense are as follows:

	For the Three Months Ended September 30, 2011							
	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 13.8	$ 4.9	$ 2.6	$ 1.0	$ 2.3	$ 0.7	$ 0.5	$ 0.2
Interest Cost	38.3	13.0	6.1	2.7	6.4	2.5	1.2	0.5
Expected Return on Plan Assets	(42.7)	(19.1)	(5.0)	(4.4)	(5.4)	(2.2)	(1.1)	(0.5)
Actuarial Loss	21.1	8.2	2.6	1.7	4.8	1.9	0.8	0.3
Prior Service Cost/(Credit)	2.4	1.1	0.5	0.2	(0.1)	-	-	-
Net Transition Obligation Cost	-	-	-	-	2.9	1.5	0.6	0.3
Total - Net Periodic Expense	$ 32.9	$ 8.1	$ 6.8	$ 1.2	$ 10.9	$ 4.4	$ 2.0	$ 0.8
Related Intercompany Allocations	$ N/A	$ 8.5	$ 1.9	$ 1.6	$ N/A	$ 2.0	$ 0.5	$ 0.4

	For the Three Months Ended September 30, 2010							
	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 12.8	$ 4.4	$ 2.5	$ 0.9	$ 2.1	$ 0.7	$ 0.4	$ 0.2
Interest Cost	38.2	13.2	6.2	2.7	6.7	2.6	1.2	0.6
Expected Return on Plan Assets	(45.7)	(21.5)	(3.7)	(4.8)	(5.4)	(2.2)	(1.0)	(0.5)
Actuarial Loss	13.4	5.1	1.7	1.0	2.9	1.6	0.7	0.2
Prior Service Cost/(Credit)	2.4	1.0	0.4	0.2	(0.1)	-	-	-
Net Transition Obligation Cost	-	-	-	-	4.2	1.5	0.6	0.3
Total - Net Periodic Expense	$ 21.1	$ 2.2	$ 7.1	$ -	$ 10.4	$ 4.2	$ 1.9	$ 0.8
Related Intercompany Allocations	$ N/A	$ 6.3	$ 1.4	$ 1.1	$ N/A	$ 2.0	$ 0.5	$ 0.3

	For the Nine Months Ended September 30, 2011							
	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 27.5	$ 14.6	$ 7.9	$ 3.0	$ 6.8	$ 2.2	$ 1.4	$ 0.4
Interest Cost	76.5	39.1	18.4	8.1	19.3	7.5	3.6	1.6
Expected Return on Plan Assets	(85.8)	(57.4)	(15.0)	(13.2)	(16.2)	(6.5)	(3.3)	(1.5)
Actuarial Loss	42.1	24.8	7.8	5.1	14.3	5.4	2.4	0.9
Prior Service Cost/(Credit)	4.8	3.1	1.5	0.6	(0.2)	-	-	-
Net Transition Obligation Cost	-	-	-	-	8.7	4.6	1.9	1.0
Total - Net Periodic Expense	$ 65.1	$ 24.2	$ 20.6	$ 3.6	$ 32.7	$ 13.2	$ 6.0	$ 2.4
Related Intercompany Allocations	$ N/A	$ 25.0	$ 5.7	$ 4.6	$ N/A	$ 6.2	$ 1.5	$ 1.1

	For the Nine Months Ended September 30, 2010							
	Pension				PBOP			
(Millions of Dollars)	**NU**	**CL&P**	**PSNH**	**WMECO**	**NU**	**CL&P**	**PSNH**	**WMECO**
Service Cost	$ 38.2	$ 13.2	$ 7.4	$ 2.5	$ 6.3	$ 2.0	$ 1.4	$ 0.4
Interest Cost	114.5	39.2	18.3	8.0	20.1	7.8	3.7	1.8
Expected Return on Plan Assets	(137.0)	(64.4)	(10.8)	(14.6)	(16.2)	(6.5)	(3.2)	(1.6)
Actuarial Loss	40.3	15.7	5.2	3.3	8.7	4.8	2.1	0.7
Prior Service Cost/(Credit)	7.3	3.0	1.1	0.7	(0.2)	-	-	-
Net Transition Obligation Cost	-	-	-	-	12.5	4.6	1.8	1.0
Total - Net Periodic Expense/(Income)	$ 63.3	$ 6.7	$ 21.2	$ (0.1)	$ 31.2	$ 12.7	$ 5.8	$ 2.3
Related Intercompany Allocations	$ N/A	$ 18.9	$ 4.4	$ 3.4	$ N/A	$ 6.0	$ 1.5	$ 1.0

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

	For the Three Months Ended		For the Nine Months Ended	
(Millions of Dollars)	**September 30, 2011**	**September 30, 2010**	**September 30, 2011**	**September 30, 2010**
NU	$ 7.8	$ 4.4	$ 23.5	$ 13.2
CL&P	4.5	1.7	13.4	5.2
PSNH	2.1	2.0	5.9	6.1
WMECO	0.7	0.2	2.1	0.5

Contributions: Currently, NU s policy is to annually fund the Pension Plan in an amount at least equal to an amount that will satisfy the requirements of ERISA, as amended by the PPA of 2006, and the Internal Revenue Code. Due to an underfunded balance as of January 1, 2010, NU is required to make an additional contribution to the Pension Plan of approximately $145 million in 2011. A contribution of approximately $124 million was made in the nine months ended September 30, 2011 ($93 million of which was contributed by PSNH). Approximately $105 million of this amount was paid in the three months ended September 30, 2011 ($78 million of which was contributed by PSNH). The required contribution is being made in installments, which began in April 2011, to meet the current minimum funding requirements established by the PPA of 2006. Based on estimates as of December 31, 2010, additional contributions totalling $390 million are expected to be made from 2012 through 2015, subject to a variety of factors, including the performance of existing plan assets, valuation of the plan's liabilities and changes in long-term discount rates.

8.

COMMITMENTS AND CONTINGENCIES

A.

Environmental Matters

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

The environmental reserve as of September 30, 2011 and December 31, 2010 related to sites in the remediation or long-term monitoring phase is as follows:

	As of September 30, 2011			As of December 31, 2010		
	Number of Sites		Reserve (in millions)	Number of Sites		Reserve (in millions)
NU	33	$	26.0	33	$	30.3
CL&P	6		0.9	6		0.8
PSNH	12		6.3	12		8.8
WMECO	8		0.2	8		0.2

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

HWP: HWP, a subsidiary of NU, continues to investigate the potential need for additional remediation at a river site in Massachusetts containing tar deposits associated with an MGP site that HWP sold to HG&E, a municipal utility, in 1902. HWP shares responsibility for site remediation with HG&E and has conducted substantial investigative and remediation activities. The cumulative expense recorded to the reserve for this site since 1994 through September 30, 2011 was $19.5 million, of which $16.9 million had been spent, leaving $2.6 million in the reserve as of September 30, 2011. For the nine months ended September 30, 2011, there was no charge recorded to the reserve and for the three and nine months ended September 30, 2010, pre-tax charges of $1.6 million and $2.6 million, respectively, were recorded to reflect estimated costs associated with the site. HWP's share of the costs related to this site is not recoverable from customers.

The $2.6 million reserve balance as of September 30, 2011 represents estimated costs that HWP considers probable over the remaining life of the project, including testing and related costs in the near term and field activities to be agreed upon with the MA DEP, further studies and long-term monitoring that are expected to be required by the MA DEP, and certain soft tar remediation activities. Various factors could affect management's estimates and require an increase to the reserve, which would be reflected as a charge to Net Income. Although a material increase to the reserve is not presently anticipated, management cannot reasonably estimate potential additional investigation or remediation costs because these costs would depend on, among other things, the nature, extent and timing of additional investigation and remediation that may be required by the MA DEP.

B.

Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant long-term contractual arrangements as of September 30, 2011 are as follows:

PSNH

(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Renewable Energy Supply Contracts	$ 5.1	$ 5.1	$ 59.9	$ 60.7	$ 70.9	$ 1,263.1	$ 1,464.8

Renewable Energy Supply Contracts: PSNH has entered into supply contracts for the purchase of electricity from renewable suppliers. Included in these amounts are payment obligations for the purchase of biomass electricity through a 20-year contract, which was approved by the NHPUC on September 2, 2011. Such contracts at PSNH extend through 2033.

C.

Guarantees and Indemnifications

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

NU provided guarantees and various indemnifications on behalf of external parties as a result of the sales of former subsidiaries of NU Enterprises, with maximum exposures either not specified or not material.

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

Management does not anticipate a material impact to Net Income to result from these various guarantees and indemnifications.

The following table summarizes NU's guarantees of its subsidiaries, including CL&P, PSNH, and WMECO, as of September 30, 2011:

Subsidiary	**Description**		**Maximum Exposure (in millions)**		**Expiration Dates**
Various	Surety Bonds and Performance Guarantees	$	16.8		2011-2012 (1)
Various	Letters of Credit	$	18.9		October 2011 - October 2012
NUSCO and RRR	Lease Payments for Vehicles and Real Estate	$	23.5		2019 and 2024
NU Enterprises	Surety Bonds, Insurance Bonds and Performance Guarantees	$	131.5	(2)	(2)

(1)

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

(2)

The maximum exposure includes $58.1 million related to performance guarantees on Select Energy's wholesale purchase contracts, which expire in 2013, assuming purchase contracts guaranteed have no value; however, actual exposures vary with underlying commodity prices. The maximum exposure also includes $15.7 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, 2011 based on limits of NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. Also included in the maximum exposure is $1.2 million related to insurance bonds at NGS with no expiration date that are billed annually on their anniversary date. The remaining $56.5 million of maximum exposure relates to surety bonds covering ongoing projects at Boulos, which expire upon project completion.

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

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

9.

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

	As of September 30, 2011							
	NU		**CL&P**		**PSNH**		**WMECO**	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred Stock Not Subject to Mandatory Redemption	$ 116.2	$ 102.0	$ 116.2	$ 102.0	$ -	$ -	$ -	$ -
Long-Term Debt	4,950.6	5,512.3	2,587.8	2,977.8	999.5	1,069.3	501.0	535.1
Rate Reduction Bonds	130.4	135.9	-	-	99.4	103.3	31.0	32.6

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

Redemption	$ 116.2	$ 93.7	$ 116.2	$ 93.7	$ -	$ -	$ -	$ -
Long-Term Debt	4,692.4	5,043.8	2,587.5	2,816.7	837.3	871.4	401.0	417.0
Rate Reduction Bonds	181.6	193.3	-	-	138.2	146.9	43.3	46.4

Derivative Instruments: NU, including CL&P and PSNH, holds various derivative instruments that are carried at fair value. For further information, see Note 4, "Derivative Instruments," to the 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 5, "Marketable Securities," to the unaudited condensed consolidated financial statements.

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

10. COMPREHENSIVE INCOME

Total comprehensive income is as follows:

	For the Three Months Ended		**For the Nine Months Ended**	
(Millions of Dollars)	**September 30, 2011 NU**	**September 30, 2010 NU**	**September 30, 2011 NU**	**September 30, 2010 NU**
Net Income	$ 91.4	$ 101.9	$ 285.7	$ 262.9
Other Comprehensive Income/(Loss), Net of Tax:				
Qualified Cash Flow Hedging Instruments	(10.7)	0.1	(14.6)	0.1
Changes in Unrealized Gains on Other Securities(1)	0.3	0.1	0.5	0.8
Change in Funded Status of Pension, SERP and PBOP Benefit Plans	1.0	0.6	2.3	1.6
Other Comprehensive Income/(Loss), Net of Tax	(9.4)	0.8	(11.8)	2.5
Total Comprehensive Income	82.0	102.7	273.9	265.4
Comprehensive Income Attributable to Noncontrolling Interests	(1.5)	(1.4)	(4.3)	(4.2)
Comprehensive Income Attributable to Controlling Interests	$ 80.5	$ 101.3	$ 269.6	$ 261.2

	For the Three Months Ended September 30, 2011			For the Three Months Ended September 30, 2010		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Net Income	$ 66.5	$ 25.6	$ 8.4	$ 69.0	$ 28.8	$ 7.3
Other Comprehensive Income/(Loss), Net of Tax:						
Qualified Cash Flow Hedging Instruments	0.1	(7.5)	(3.2)	0.1	-	-
Other Comprehensive Income/(Loss), Net of Tax	0.1	(7.5)	(3.2)	0.1	-	-
Total Comprehensive Income	$ 66.6	$ 18.1	$ 5.2	$ 69.1	$ 28.8	$ 7.3

	For the Nine Months Ended September 30, 2011			For the Nine Months Ended September 30, 2010		
(Millions of Dollars)	**CL&P**	**PSNH**	**WMECO**	**CL&P**	**PSNH**	**WMECO**
Net Income	$ 183.5	$ 74.8	$ 26.6	$ 161.5	$ 66.2	$ 18.2
Other Comprehensive Income/(Loss), Net of Tax:						
Qualified Cash Flow Hedging Instruments	0.3	(10.6)	(4.2)	0.4	0.1	(0.1)
Other Comprehensive Income/(Loss), Net of Tax	0.3	(10.6)	(4.2)	0.4	0.1	(0.1)
Total Comprehensive Income	$ 183.8	$ 64.2	$ 22.4	$ 161.9	$ 66.3	$ 18.1

(1) Represents changes in unrealized gains on securities held in the NU supplemental benefit trust.

Qualified cash flow hedging instruments for the nine months ended September 30, 2011 are as follows:

	For the Nine Months Ended September 30, 2011		
(Millions of Dollars)	**NU**	**PSNH**	**WMECO**
Balance as of Beginning of Period	$ (4.2)	$ (0.6)	$ (0.1)
Hedged Transactions Recognized into Earnings	0.3	0.2	-
Cash Flow Hedging Transactions Entered into for the Period	(14.9)	(10.8)	(4.2)
Net Change Associated with Hedging Transactions	(14.6)	(10.6)	(4.2)
Total Fair Value Adjustments Included in Accumulated Other Comprehensive Income	$ (18.8)	$ (11.2)	$ (4.3)

For further information regarding cash flow hedging transactions, see Note 4, "Derivative Instruments," to the unaudited condensed consolidated financial statements.

11.

COMMON SHARES

The following table sets forth the NU common shares and the shares of CL&P, PSNH and WMECO common stock authorized and issued as of September 30, 2011 and December 31, 2010 and the respective par values:

			Shares		
			Authorized	Issued	
	Per Share Par Value		As of September 30, 2011 and December 31, 2010	As of September 30, 2011	As of December 31, 2010
NU	$	5	225,000,000	196,010,807	195,781,740
CL&P	$	10	24,500,000	6,035,205	6,035,205
PSNH	$	1	100,000,000	301	301
WMECO	$	25	1,072,471	434,653	434,653

As of September 30, 2011 and December 31, 2010, 19,008,390 and 19,333,659 NU common shares were held as treasury shares, respectively.

12. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS (NU)

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

	For the Three Months Ended							
	September 30, 2011				September 30, 2010			
(Millions of Dollars)	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Preferred Stock Not Subject to Mandatory Redemption	Common Shareholders' Equity	Noncontrolling Interest	Total Equity	Preferred Stock Not Subject to Mandatory Redemption
Balance, Beginning of Period	$ 3,915.1	$ 1.8	$ 3,916.9	$ 116.2	$ 3,658.9	$ 1.1	$ 3,660.0	$ 116.2
Net Income	91.4	-	91.4	-	101.9	-	101.9	-
Dividends on Common Shares	(48.9)	-	(48.9)	-	(45.4)	-	(45.4)	-
	(1.4)	-	(1.4)	(1.4)	(1.4)	-	(1.4)	(1.4)

Dividends on Preferred Stock								
Issuance of Common Shares	0.9	-	0.9	-	1.1	-	1.1	-
Contributions to NPT	-	0.6	0.6	-	-	0.3	0.3	-
Other Transactions, Net	8.5	-	8.5	-	6.8	-	6.8	-
Net Income Attributable to Noncontrolling Interests	-	0.1	0.1	1.4	-	-	-	1.4
Other Comprehensive Income (Note 10)	(9.4)	-	(9.4)	-	0.8	-	0.8	-
Balance, End of Period	$ 3,956.2	$ 2.5	$ 3,958.7	$ 116.2	$ 3,722.7	$ 1.4	$ 3,724.1	$ 116.2

	For the Nine Months Ended							
	September 30, 2011				September 30, 2010			
(Millions of Dollars)	**Common Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Preferred Stock Not Subject to Mandatory Redemption**	**Common Shareholders' Equity**	**Noncontrolling Interest**	**Total Equity**	**Preferred Stock Not Subject to Mandatory Redemption**
Balance, Beginning of Period	$ 3,811.2	$ 1.5	$ 3,812.7	$ 116.2	$ 3,577.9	$ -	$ 3,577.9	$ 116.2
Net Income	285.7	-	285.7	-	262.9	-	262.9	-
Dividends on Common Shares	(146.6)	-	(146.6)	-	(136.3)	-	(136.3)	-
Dividends on Preferred Stock	(4.2)	-	(4.2)	(4.2)	(4.2)	-	(4.2)	(4.2)
Issuance of Common Shares	5.1	-	5.1	-	6.5	-	6.5	-
Contributions to NPT	-	0.9	0.9	-	-	1.4	1.4	-
Other Transactions, Net	16.8	-	16.8	-	13.4	-	13.4	-
Net Income Attributable to Noncontrolling Interests	-	0.1	0.1	4.2	-	-	-	4.2
Other Comprehensive Income (Note 10)	(11.8)	-	(11.8)	-	2.5	-	2.5	-
Balance, End of Period	$ 3,956.2	$ 2.5	$ 3,958.7	$ 116.2	$ 3,722.7	$ 1.4	$ 3,724.1	$ 116.2

For the three and nine months ended September 30, 2011 and 2010, there was no change in NU parent's 100 percent ownership of the common equity of CL&P.

13.

EARNINGS PER SHARE (NU)

EPS is computed based upon the monthly weighted average number of common shares outstanding, excluding unallocated 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 shares. 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 months ended September 30, 2010, there were 2,104 share awards excluded from the computation, as these awards were antidilutive. There were no antidilutive share awards outstanding for the nine months ended September 30, 2011 or for the three months ended September 30, 2011 and 2010.

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

(Millions of Dollars, except share information)	**For the Three Months Ended September 30, 2011**	**September 30, 2010**	**For the Nine Months Ended September 30, 2011**	**September 30, 2010**
Net Income Attributable to Controlling Interests	$ 90.0	$ 100.5	$ 281.4	$ 258.7
Weighted Average Common Shares Outstanding:				
Basic	177,497,862	176,752,714	177,344,481	176,557,889
Dilutive Effect	337,486	259,564	303,213	204,199
Diluted	177,835,348	177,012,278	177,647,694	176,762,088
Basic EPS	$ 0.51	$ 0.57	$ 1.59	$ 1.47
Diluted EPS	$ 0.51	$ 0.57	$ 1.58	$ 1.46

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

The dilutive effect of stock options to purchase common shares is also calculated using the treasury stock method. Assumed proceeds for stock options consist of 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 during the period, and the exercise price).

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

14.

SEGMENT INFORMATION

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

The Regulated companies' segments include the electric distribution segment, the natural gas distribution segment and the electric transmission segment. The electric distribution segment includes the generation activities of PSNH and WMECO. The Regulated companies' segments represented substantially all of NU's total consolidated revenues for the three and nine month periods ended September 30, 2011 and 2010.

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 NU Enterprises (NU's competitive businesses, which primarily consist of Select Energy's remaining wholesale marketing contracts, an electrical contracting business and other operating and maintenance services contracts), RRR (a real estate subsidiary), the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company and Yankee Energy Financial Services Company) and the remaining operations of HWP that were not exited as part of the sale of the competitive generation business in 2006 and the sale of its transmission business to WMECO in December 2008.

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

NU's segment information for the three and nine months ended September 30, 2011 and 2010, with the distribution segment segregated between electric and natural gas, is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	For the Three Months Ended September 30, 2011					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 878.6	$ 59.6	$ 159.1	$ 142.3	$ (124.7)	$ 1,114.9
Depreciation and Amortization	(99.3)	(7.2)	(19.5)	(4.4)	0.8	(129.6)
Other Operating Expenses	(666.2)	(52.3)	(46.7)	(135.7)	119.4	(781.5)
Operating Income	113.1	0.1	92.9	2.2	(4.5)	203.8
Interest Expense	(30.3)	(5.3)	(21.3)	(8.1)	1.1	(63.9)
Interest Income	0.9	-	0.1	1.3	(1.3)	1.0
Other Income/(Loss), Net	0.6	0.4	(1.1)	86.3	(85.8)	0.4
Income Tax (Expense)/Benefit	(25.5)	1.8	(28.5)	4.1	(1.8)	(49.9)
Net Income/(Loss)	58.8	(3.0)	42.1	85.8	(92.3)	91.4
Net Income Attributable to Noncontrolling Interests	(0.8)	-	(0.6)	-	-	(1.4)

Net Income/(Loss) Attributable to Controlling Interests	$	58.0	$	(3.0)	$	41.5	$	85.8	$	(92.3)	$	90.0

	For the Nine Months Ended September 30, 2011											
	Regulated Companies											
	Distribution											
(Millions of Dollars)	Electric		Natural Gas		Transmission		Other		Eliminations		Total	
Operating Revenues	$	2,564.7	$	318.1	$	469.4	$	403.5	$	(358.1)	$	3,397.6
Depreciation and Amortization		(268.1)		(20.2)		(64.3)		(12.7)		2.1		(363.2)
Other Operating Expenses		(1,991.3)		(251.5)		(139.2)		(397.4)		354.3		(2,425.1)
Operating Income/(Expense)		305.3		46.4		265.9		(6.6)		(1.7)		609.3
Interest Expense		(90.9)		(15.6)		(56.6)		(25.3)		3.7		(184.7)
Interest Income		2.7		-		0.4		4.0		(4.0)		3.1
Other Income, Net		7.1		1.2		7.0		321.2		(320.6)		15.9
Income Tax (Expense)/Benefit		(69.0)		(11.3)		(86.4)		11.9		(3.1)		(157.9)
Net Income		155.2		20.7		130.3		305.2		(325.7)		285.7
Net Income Attributable to Noncontrolling Interests		(2.4)		-		(1.9)		-		-		(4.3)
Net Income Attributable to Controlling Interests	$	152.8	$	20.7	$	128.4	$	305.2	$	(325.7)	$	281.4
Total Assets (as of)	$	9,041.3	$	1,456.8	$	3,727.3	$	6,186.8	$	(5,683.5)	$	14,728.7
Cash Flows for Total Investments in Plant	$	385.0	$	73.6	$	254.2	$	36.3	$	-	$	749.1

	For the Three Months Ended September 30, 2010					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 1,010.5	$ 59.6	$ 159.4	$ 131.7	$ (117.9)	$ 1,243.3
Depreciation and Amortization	(150.0)	(6.6)	(22.0)	(4.3)	1.2	(181.7)
Other Operating Expenses	(751.3)	(52.5)	(50.5)	(128.4)	120.7	(862.0)
Operating Income/(Loss)	109.2	0.5	86.9	(1.0)	4.0	199.6
Interest Expense	(34.8)	(5.5)	(18.9)	(7.8)	1.1	(65.9)
Interest Income	0.6	-	0.4	1.3	(1.3)	1.0
Other Income, Net	5.3	0.3	5.0	102.2	(103.7)	9.1
Income Tax (Expense)/Benefit	(20.9)	1.7	(27.6)	5.2	(0.3)	(41.9)
Net Income/(Loss)	59.4	(3.0)	45.8	99.9	(100.2)	101.9
Net Income Attributable to Noncontrolling Interests	(0.8)	-	(0.6)	-	-	(1.4)
Net Income/(Loss) Attributable to Controlling Interests	$ 58.6	$ (3.0)	$ 45.2	$ 99.9	$ (100.2)	$ 100.5

	For the Nine Months Ended September 30, 2010					
	Regulated Companies					
	Distribution					
(Millions of Dollars)	**Electric**	**Natural Gas**	**Transmission**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 2,895.0	$ 304.9	$ 467.2	$ 389.7	$ (362.6)	$ 3,694.2
Depreciation and Amortization	(364.7)	(17.2)	(63.9)	(11.7)	2.8	(454.7)
Other Operating Expenses	(2,249.0)	(244.3)	(142.8)	(361.3)	362.5	(2,634.9)
Operating Income	281.3	43.4	260.5	16.7	2.7	604.6
Interest Expense	(107.0)	(15.8)	(57.5)	(23.5)	3.4	(200.4)
Interest Income/(Loss)	(0.2)	-	1.8	4.0	(5.1)	0.5
Other Income, Net	9.5	0.4	9.0	285.9	(285.5)	19.3
Income Tax (Expense)/Benefit	(66.5)	(11.9)	(84.8)	2.7	(0.6)	(161.1)
Net Income	117.1	16.1	129.0	285.8	(285.1)	262.9
Net Income Attributable to Noncontrolling Interests	(2.5)	-	(1.7)	-	-	(4.2)
Net Income Attributable to Controlling Interests	$ 114.6	$ 16.1	$ 127.3	$ 285.8	$ (285.1)	$ 258.7
Total Assets (as of)	$ 8,850.0	$ 1,404.7	$ 3,376.3	$ 6,113.9	$ (5,447.3)	$ 14,297.6
Cash Flows for Total						

Investments in Plant	$ 403.9	$ 52.8	$ 170.6	$ 50.3	$ -	$ 677.6

The information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the three and nine months
ended September 30, 2011 and 2010 is as follows:

	CL&P - For the Three Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 552.6	$ 121.1	$ 673.7	$ 662.5	$ 126.7	$ 789.2
Depreciation and Amortization	(40.0)	(15.4)	(55.4)	(98.0)	(16.9)	(114.9)
Other Operating Expenses	(446.7)	(33.9)	(480.6)	(504.6)	(38.3)	(542.9)
Operating Income	65.9	71.8	137.7	59.9	71.5	131.4
Interest Expense	(18.0)	(17.2)	(35.2)	(21.0)	(15.7)	(36.7)
Interest Income	0.6	0.1	0.7	0.5	0.3	0.8
Other Income/(Loss), Net	(1.5)	(1.6)	(3.1)	3.0	3.1	6.1
Income Tax Expense	(11.6)	(22.0)	(33.6)	(10.1)	(22.5)	(32.6)
Net Income	$ 35.4	$ 31.1	$ 66.5	$ 32.3	$ 36.7	$ 69.0

	CL&P - For the Nine Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 1,592.5	$ 362.9	$ 1,955.4	$ 1,917.8	$ 374.3	$ 2,292.1
Depreciation and Amortization	(117.7)	(48.7)	(166.4)	(264.4)	(50.4)	(314.8)
Other Operating Expenses	(1,306.5)	(104.0)	(1,410.5)	(1,505.9)	(108.3)	(1,614.2)
Operating Income	168.3	210.2	378.5	147.5	215.6	363.1
Interest Expense	(53.0)	(46.3)	(99.3)	(64.9)	(47.5)	(112.4)
Interest Income	1.9	0.3	2.2	1.4	1.4	2.8
Other Income/(Loss), Net	(0.3)	2.5	2.2	4.1	5.6	9.7
Income Tax Expense	(32.3)	(67.8)	(100.1)	(31.4)	(70.3)	(101.7)
Net Income	$ 84.6	$ 98.9	$ 183.5	$ 56.7	$ 104.8	$ 161.5
Total Assets (as of)	$ 5,748.0	$ 2,637.7	$ 8,385.7	$ 5,664.7	$ 2,588.8	$ 8,253.5
Cash Flows for Total Investments in Plant	$ 221.1	$ 84.5	$ 305.6	$ 192.4	$ 81.8	$ 274.2

	PSNH - For the Three Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 237.5	$ 22.1	$ 259.6	$ 256.1	$ 20.9	$ 277.0
Depreciation and Amortization	(46.4)	(2.9)	(49.3)	(42.3)	(2.5)	(44.8)
Other Operating Expenses	(152.7)	(9.1)	(161.8)	(173.7)	(8.7)	(182.4)
Operating Income	38.4	10.1	48.5	40.1	9.7	49.8
Interest Expense	(8.4)	(2.0)	(10.4)	(9.4)	(2.1)	(11.5)
Interest Income	0.2	-	0.2	0.1	-	0.1
Other Income, Net	2.9	0.2	3.1	3.1	0.5	3.6
Income Tax Expense	(12.5)	(3.3)	(15.8)	(10.4)	(2.8)	(13.2)
Net Income	$ 20.6	$ 5.0	$ 25.6	$ 23.5	$ 5.3	$ 28.8

	PSNH - For the Nine Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 704.5	$ 64.8	$ 769.3	$ 713.3	$ 60.6	$ 773.9
Depreciation and Amortization	(121.0)	(8.5)	(129.5)	(76.3)	(7.8)	(84.1)
Other Operating Expenses	(481.4)	(25.1)	(506.5)	(532.2)	(24.5)	(556.7)
Operating Income	102.1	31.2	133.3	104.8	28.3	133.1
Interest Expense	(25.5)	(5.7)	(31.2)	(29.5)	(6.3)	(35.8)
Interest Income/(Loss)	0.7	0.1	0.8	(1.9)	0.2	(1.7)
Other Income, Net	10.1	1.3	11.4	6.5	1.1	7.6
Income Tax Expense	(29.3)	(10.2)	(39.5)	(28.4)	(8.6)	(37.0)
Net Income	$ 58.1	$ 16.7	$ 74.8	$ 51.5	$ 14.7	$ 66.2
Total Assets (as of)	$ 2,404.7	$ 536.1	$ 2,940.8	$ 2,319.5	$ 477.5	$ 2,797.0
Cash Flows for Total Investments in Plant	$ 133.3	$ 34.1	$ 167.4	$ 185.6	$ 32.4	$ 218.0

	WMECO - For the Three Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 88.7	$ 15.8	$ 104.5	$ 91.9	$ 11.8	$ 103.7
Depreciation and Amortization	(12.9)	(1.2)	(14.1)	(9.8)	(2.6)	(12.4)
Other Operating Expenses	(67.0)	(3.6)	(70.6)	(72.9)	(3.5)	(76.4)
Operating Income	8.8	11.0	19.8	9.2	5.7	14.9
Interest Expense	(3.9)	(2.1)	(6.0)	(4.5)	(1.1)	(5.6)
Interest Income	0.1	-	0.1	0.1	-	0.1
Other Income/(Loss), Net	(0.8)	(0.1)	(0.9)	(0.8)	1.4	0.6
Income Tax Expense	(1.4)	(3.2)	(4.6)	(0.3)	(2.4)	(2.7)

Net Income [1]	$ 2.8	$ 5.6	$ 8.4	$ 3.7	$ 3.6	$ 7.3

	WMECO - For the Nine Months Ended					
	September 30, 2011			September 30, 2010		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**	**Distribution**	**Transmission**	**Total**
Operating Revenues	$ 268.0	$ 41.6	$ 309.6	$ 264.1	$ 32.3	$ 296.4
Depreciation and Amortization	(29.5)	(7.1)	(36.6)	(23.9)	(5.7)	(29.6)
Other Operating Expenses	(203.6)	(10.1)	(213.7)	(211.1)	(10.1)	(221.2)
Operating Income	34.9	24.4	59.3	29.1	16.5	45.6
Interest Expense	(12.4)	(4.6)	(17.0)	(12.6)	(3.6)	(16.2)
Interest Income	0.3	-	0.3	0.3	0.2	0.5
Other Income/(Loss), Net	(2.7)	2.7	-	(1.2)	2.1	0.9
Income Tax Expense	(7.6)	(8.4)	(16.0)	(6.7)	(5.9)	(12.6)
Net Income	$ 12.5	$ 14.1	$ 26.6	$ 8.9	$ 9.3	$ 18.2
Total Assets (as of)	$ 893.1	$ 526.7	$ 1,419.8	$ 868.7	$ 300.0	$ 1,168.7
Cash Flows for Total Investments in Plant	$ 30.6	$ 122.9	$ 153.5	$ 26.0	$ 51.7	$ 77.7

(1)

Distribution segment Net Income for the three months ended September 30, 2011 decreased by $3.2 million as compared to the three months ended September 30, 2010 related to a pre-tax charge to establish a reserve of $5.3 million to reflect a wholesale billing adjustment, $4.3 million of which related to prior period amounts.

15.

VARIABLE INTEREST ENTITIES

The Company's variable interests outside of the consolidated group are not material and consist of contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. NU holds variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants and with other independent power producers. NU does not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, NU does not consolidate any power plant VIEs.

16.

SUBSEQUENT EVENTS (NU, CL&P)

On October 14, 2011, NU and NSTAR extended the termination date of the merger agreement from October 16, 2011 to April 16, 2012.

On October 24, 2011, CL&P issued $120.5 million of PCRBs carrying a coupon of 4.375 percent that will mature on September 1, 2028 and $125 million of PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of CL&P s issuances were used to refund $245.5 million of PCRBs that carried a coupon of 5.85 percent and had a maturity date of September 1, 2028.

On October 29, 2011, a snowstorm delivered high winds and heavy snowfall across the NU service territory, causing significant damage to NU s distribution and transmission systems. For further information on the October 29, 2011 snowstorm, see Note 2, "Regulatory Accounting," to the 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 First and Second Quarter 2011 Forms 10-Q, and the 2010 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 diluted basis.

Refer to the Glossary of Terms included in this combined Quarterly Report on Form 10-Q for abbreviations and acronyms used throughout this *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

The only common equity securities that are publicly traded are common shares of NU. The earnings and EPS of each business discussed below do not represent a direct legal interest in the assets and liabilities allocated to such business but rather represent a direct interest in our assets and liabilities as a whole. EPS by business is a financial measure not recognized under GAAP that is calculated by dividing the Net Income Attributable to Controlling Interests of each business by the weighted average diluted NU common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to provide details of earnings results and guidance by business. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our businesses. This non-GAAP financial measure should not be considered as an alternative to our consolidated diluted EPS determined in accordance with GAAP as an indicator of operating performance.

The discussion below also includes a non-GAAP financial measure referencing our third quarter and first nine months of 2011 earnings and EPS excluding expenses related to NU's pending merger with NSTAR. We use this non-GAAP financial measure to more fully compare and explain the third quarter and first nine months of 2011 and 2010 results without including the impact of this non-recurring item. Due to the nature and significance of this item on Net Income, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to readers of this report in analyzing historical and future performance. This non-GAAP financial measure should not be considered as an alternative to reported Net Income Attributable to Controlling Interests or EPS determined in accordance with GAAP as an indicator of operating performance.

Reconciliations of the above non-GAAP financial measures to the most directly comparable GAAP measures of consolidated diluted EPS and Net Income Attributable to Controlling Interests are included under "Financial Condition and Business Analysis Overview Consolidated" and "Financial Condition and Business Analysis Future

Outlook" in *Management's Discussion and Analysis*, herein. All forward-looking information for 2011 and thereafter provided in this *Management s Discussion and Analysis* assumes we will operate on a stand-alone basis, excluding the impacts of the pending merger with NSTAR, unless otherwise indicated.

Forward-Looking Statements: From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our forward-looking statements through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to:

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actions or inaction by local, state and federal regulatory and taxing bodies,

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changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services,

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changes in weather patterns,

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changes in laws, regulations or regulatory policy,

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changes in levels and timing of capital expenditures,

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

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developments in legal or public policy doctrines,

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technological developments,

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changes in accounting standards and financial reporting regulations,

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fluctuations in the value of our remaining competitive contracts,

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actions of rating agencies,

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the expected timing and likelihood of completion of the pending merger with NSTAR, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the pending merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, as well as the ability to successfully integrate the businesses, and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect, and

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other presently unknown or unforeseen factors.

Other risk factors are detailed in our reports filed with the SEC and updated as necessary, and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A, *Risk Factors,* included in this Quarterly Report on Form 10-Q and in our 2010 Form 10-K. This Quarterly Report on Form 10-Q and our 2010 Form 10-K also describe material contingencies and critical accounting policies and estimates in the accompanying *Management's Discussion and Analysis* and *Combined Notes to Consolidated Financial Statements*. We encourage you to review these items.

Financial Condition and Business Analysis

Pending Merger with NSTAR:

On October 18, 2010, we and NSTAR announced that each company's Board of Trustees unanimously approved a merger agreement (the "agreement"), under which NSTAR will become a direct wholly owned subsidiary of NU. On October 14, 2011, NU and NSTAR extended the termination date of the agreement, as defined therein, from October 16, 2011 to April 16, 2012. The transaction is structured as a merger of equals in a tax-free exchange of shares. Under the terms of the agreement, NSTAR shareholders will receive 1.312 NU common shares for each NSTAR common share that they own (the "exchange ratio"). Post-transaction, NU will provide electric and natural gas energy delivery service to approximately 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire. On March 4, 2011, NU shareholders approved the agreement, approved an increase to the number of NU common shares authorized for issuance by 155 million common shares to 380 million authorized common shares and fixed the number of trustees at 14. NSTAR shareholders approved the agreement on March 4, 2011.

Subject to the conditions in the agreement, our first quarterly dividend per common share paid after the closing of the merger will be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. In Massachusetts, NU and NSTAR await the DPU s approval. On July 15, 2011, the Massachusetts Department of Energy Resources filed a motion for a stay of the proceedings. On July 21, 2011, NU and NSTAR filed a response objecting to this motion. Oral arguments on the request for a stay are scheduled for

November 17, 2011. The companies anticipate that the regulatory approvals can be obtained to permit the merger to close late in the fourth quarter of 2011 or early 2012. For further information regarding regulatory approvals on the pending merger, see "Regulatory Developments and Rate Matters   Regulatory Approvals for Pending Merger with NSTAR," in this *Management's Discussion and Analysis.*

Executive Summary

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

Results:

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We earned $90 million, or $0.51 per share, in the third quarter of 2011, and $281.4 million, or $1.58 per share, in the first nine months of 2011, compared with $100.5 million, or $0.57 per share, in the third quarter of 2010, and $258.7 million, or $1.46 per share, in the first nine months of 2010. Excluding merger-related costs of $0.6 million, or less than $0.01 per share, and $10.1 million, or $0.06 per share, we earned $90.6 million, or $0.51 per share, and $291.5 million, or $1.64 per share, in the third quarter and first nine months of 2011, respectively. Lower results in the third quarter of 2011 were due primarily to net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010, a third quarter WMECO charge to establish a reserve related to a wholesale billing adjustment, lower competitive business results, and a higher effective tax rate. Improved results in the first nine months of 2011 were primarily attributable to the impact of recent electric distribution rate case decisions as well as colder than normal weather in the first quarter of 2011.

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Our Regulated companies earned $96.5 million, or $0.54 per share, in the third quarter of 2011 and $301.9 million, or $1.70 per share, in the first nine months of 2011, compared with earnings of $100.9 million, or $0.57 per share, in the third quarter of 2010, and $258 million, or $1.46 per share, in the first nine months of 2010.

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The distribution segment of our Regulated companies earned $55 million, or $0.31 per share, in the third quarter of 2011 and $173.5 million, or $0.98 per share, in the first nine months of 2011, compared with $55.7 million, or $0.31 per share, in the third quarter of 2010, and $130.7 million, or $0.74 per share, in the first nine months of 2010. The transmission segment of our Regulated companies earned $41.5 million, or $0.23 per share, in the third quarter of 2011 and $128.4 million, or $0.72 per share, in the first nine months of 2011, compared with $45.2 million, or $0.26 per share, in the third quarter of 2010, and $127.3 million, or $0.72 per share, in the first nine months of 2010.

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NU parent and other companies recorded net expenses of $6.5 million, or $0.03 per share, in the third quarter of 2011 and $20.5 million, or $0.12 per share, in the first nine months of 2011, compared with net expenses of $0.4 million, or less than $0.01 per share, in the third quarter of 2010 and earnings of $0.7 million, or less than $0.01 per share, in the first nine months of 2010. Excluding merger-related costs of $0.6 million, or less than $0.01 per share, and $10.1 million, or $0.06 per share, NU parent and other companies recorded net expenses of $5.9 million, or $0.03 per share, and $10.4 million, or $0.06 per share, in the third quarter and first nine months of 2011, respectively.

Outlook:

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We continue to project consolidated 2011 earnings of between $2.30 per share and $2.40 per share, excluding projected after-tax merger-related costs of approximately $0.20 per share. This projection includes distribution segment earnings of between $1.30 per share and $1.35 per share, transmission segment earnings of between $1.05 per share and $1.10 per share, and net expenses at NU parent and other companies of approximately $0.05 per share, excluding merger-related costs.

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We now project capital expenditures for 2012 through 2016 of approximately $5.7 billion. During that time period, we expect the Regulated companies rate base to rise from approximately $8.2 billion at the end of 2011 to approximately $11.2 billion at the end of 2016.

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While the company is providing detailed stand-alone capital expenditures and rate base projections through 2016, it has not updated its previous statements concerning a stand-alone five-year compound earnings per share growth rate due to management's expectation that the merger with NSTAR may close in either late 2011 or early 2012.

Strategy, Legislative, Regulatory and Other Items:

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On August 28, 2011, Tropical Storm Irene caused extensive damage to NU s distribution system resulting in restoration costs of approximately $142 million. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut. The storm met the criteria for specific cost recovery and as a result, it had no material impact on our results of operations. A number of governmental inquiries have been opened in Connecticut to review the response of utilities and other entities to the storm. We believe our response was sound and prudent. CL&P will seek recovery of deferred storm costs through the appropriate regulatory recovery process.

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On October 29, 2011, a snowstorm delivered high winds and heavy snowfall across our service territory, causing significant damage to our distribution and transmission systems. Approximately 1.2 million NU customers were without power at the peak of the outages. This was the largest in CL&P s and WMECO's history and third largest in PSNH s history in terms of customer outages. As a result of the magnitude of the damage and the anticipated costs of restoring service, we expect such costs to meet the criteria for recovery in Connecticut, New Hampshire, and Massachusetts and we do not expect the storm to have a material impact to the results of operations of CL&P, PSNH or WMECO. Each operating company will seek recovery of these anticipated deferred storm costs through its applicable regulatory recovery process.

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On September 30, 2011, several parties filed a joint complaint with the FERC alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission owners, including CL&P, PSNH and WMECO, is unjust and unreasonable, and seeking an order to reduce the rate from 11.14 percent to 9.2 percent. On October 20, 2011, the New England transmission owners filed their response seeking dismissal of the complaint on the basis that the complainants failed to demonstrate that the existing base ROE is unjust and unreasonable. In their response, the New England transmission owners included testimony and analysis demonstrating that the 11.14 percent base ROE remains just and reasonable.

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On September 29, 2011, the EPA issued a draft renewal National Pollutant Discharge Elimination System (NPDES) permit under the Clean Water Act for PSNH s Merrimack Station for public review and comment. The draft permit would require PSNH to install a closed-cycle cooling system at the station. The EPA estimated that the net present value cost to install this system and operate it over a 20-year period would be approximately $112 million. On October 27, 2011, the EPA extended the initial 60-day period for public review and comment on the draft permit for an additional 90 days until February 28, 2012. The EPA has no set deadline to consider comments and to issue a final permit. Merrimack Station can continue to operate under its present permit pending issuance of the final permit and subsequent resolution of matters appealed by PSNH and other parties. Due to the site specific characteristics of PSNH's other fossil generating stations, we believe it is unlikely that they would have similar permit requirements imposed on them.

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On September 13, 2011, CL&P and WMECO received the required permit from U.S. Army Corps of Engineers allowing them to commence full construction of GSRP. The $718 million project is expected to be placed in service in late 2013.

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On June 29, 2011, the DPUC (now PURA) issued a final decision in the Yankee Gas rate proceeding. On September 28, 2011, PURA amended that decision and allowed Yankee Gas   proposal to reduce accumulated deferred income taxes (ADIT) by the tax effect of net operating loss. The revisions will increase Yankee Gas   revenues by $0.4 million and $0.7 million for the twelve months ended June 30, 2012 and 2013, respectively.

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In September 2011, the Clean Air Project was placed in service at PSNH s Merrimack Station. Operational testing is underway and finalization of project activities is expected to conclude in early 2012. We currently expect the project to cost approximately $422 million, as compared to the previous estimate of approximately $430 million.

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Yankee Gas WWL project has been completed and is expected to be placed in service in November 2011. The project cost approximately $54 million, $3.6 million below the previous estimate of $57.6 million.

Liquidity:

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Cash and cash equivalents totaled $16.7 million as of September 30, 2011, compared with $23.4 million as of December 31, 2010.

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Cash capital expenditures totaled $749.1 million in the first nine months of 2011, compared with $677.6 million in the first nine months of 2010.

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Cash flows provided by operating activities totaled $837.2 million in the first nine months of 2011, compared with $647.9 million in the first nine months of 2010 (amounts are net of RRB payments). The 2011 improved cash flows were due primarily to the impact of the recent electric distribution rate case decisions and a decrease in income tax payments largely attributable to the accelerated depreciation tax benefits. Offsetting these benefits was a contribution of approximately $124 million into the NU Pension Plan. We now project 2011 cash flows provided by operating activities will total between $800 million and $850 million, compared with the previous estimate of $900 million to $950 million. The decline is due primarily to the preliminary cost estimates of approximately $142 million associated with Tropical Storm Irene. Those cash flows are likely to decrease due to the anticipated restoration costs of the October 29, 2011 snowstorm.

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On September 13, 2011, PSNH issued $160 million of 3.20 percent first mortgage bonds that will mature on September 1, 2021. On September 16, 2011, WMECO issued $100 million of 3.50 percent unsecured senior notes that will mature on September 15, 2021. On October 24, 2011, CL&P issued $120.5 million of 4.375 percent PCRBs that will mature on September 1, 2028 and $125 million of 1.25 percent PCRBs that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of CL&P s issuances were used to refund $245.5 million of PCRBs that carried a coupon of 5.85 percent and had a maturity date of September 1, 2028.

Overview

Consolidated: A summary of our earnings by business, which also reconciles the non-GAAP financial measures of consolidated non-GAAP earnings and EPS, as well as EPS by business, to the most directly comparable GAAP measures of consolidated Net Income Attributable to Controlling Interests and diluted EPS, for the third quarter and first nine months of 2011 and 2010 is as follows:

(Millions of Dollars, Except Per Share Amounts)	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	2011		**2010**		**2011**		**2010**	
	Amount	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income Attributable to Controlling Interests (GAAP)	$ 90.0	$ 0.51	$ 100.5	$ 0.57	$ 281.4	$ 1.58	$ 258.7	$ 1.46
Regulated Companies	$ 96.5	$ 0.54	$ 100.9	$ 0.57	$ 301.9	$ 1.70	$ 258.0	$ 1.46
NU Parent and Other Companies	(5.9)	(0.03)	(0.4)	-	(10.4)	(0.06)	0.7	-
Non-GAAP Earnings	90.6	0.51	100.5	0.57	291.5	1.64	258.7	1.46
Merger-Related Costs (after-tax)	(0.6)	-	-	-	(10.1)	(0.06)	-	-
Net Income Attributable to Controlling Interests (GAAP)	$ 90.0	$ 0.51	$ 100.5	$ 0.57	$ 281.4	$ 1.58	$ 258.7	$ 1.46

Lower results in the third quarter of 2011 were due primarily to net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010, a third quarter WMECO charge to establish a reserve related to a wholesale billing adjustment, lower competitive business results, lower retail electric sales that resulted from milder weather in the summer of 2011, compared with warmer than normal weather in the summer of 2010, a higher effective tax rate driven primarily by the negative impact of return to provision adjustments in the third quarter of 2011, as compared to the positive impact in the third quarter of 2010, and higher operations and maintenance costs.

Improved results in the first nine months of 2011 were due primarily to the impact of electric distribution rate case decisions that were effective July 1, 2010 for CL&P and PSNH and February 1, 2011 for WMECO, colder than normal weather in the first quarter of 2011, continued cost management efforts, and the absence of a net after-tax charge of approximately $3 million, or approximately $0.02 per share, taken in the first quarter of 2010 associated with the enactment of the 2010 Healthcare Act. These benefits were partially offset by the third quarter 2011 items described above, a decline in NU parent and other companies' results, a second quarter 2011 refund to transmission wholesale customers, as compared to a recovery from those customers in 2010, as well as higher pension and healthcare costs, depreciation, and property taxes. Retail electric sales were down 0.2 percent and firm natural gas sales were up 15.7 percent in the first nine months of 2011, compared to the same period in 2010.

Regulated Companies: Our Regulated companies consist of the distribution and electric transmission segments, with the Yankee Gas natural gas distribution segment and PSNH and WMECO generation activities included in the distribution segment. A summary of our Regulated companies' earnings by segment for the third quarter and first nine months of 2011 and 2010 is as follows:

(Millions of Dollars)	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
CL&P Transmission	$ 30.5	$ 36.1	$ 97.2	$ 103.1
PSNH Transmission	5.1	5.3	16.6	14.7
WMECO Transmission	5.6	3.7	14.1	9.4
NPT	0.3	0.1	0.5	0.1
Total Transmission	41.5	45.2	128.4	127.3
CL&P Distribution	34.6	31.5	82.2	54.2
PSNH Distribution	20.6	23.4	58.1	51.5
WMECO Distribution	2.8	3.7	12.5	8.9
Yankee Gas	(3.0)	(2.9)	20.7	16.1
Total Distribution	55.0	55.7	173.5	130.7
Net Income - Regulated Companies	$ 96.5	$ 100.9	$ 301.9	$ 258.0

For the third quarter of 2011, the transmission segment earnings were $3.7 million lower than the third quarter of 2010 due primarily to the allocation of the net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010, primarily impacting CL&P, and higher income taxes, particularly at CL&P. In addition, CL&P s third quarter 2011 transmission segment earnings reflected the impacts of its May 2011 sale of certain transmission lines having a net book value of $42.5 million. CL&P also was impacted, from a rate base standpoint, by a large amount of accelerated depreciation tax benefits, which reduced the overall amount of transmission investment on which CL&P earns a return. These losses were partially offset by a higher level of investment in transmission infrastructure.

For the first nine months of 2011, the transmission segment earnings were $1.1 million higher than the same period of 2010 due primarily to a higher level of investment in transmission infrastructure, and a higher proportion of equity funding to support the transmission investments, partially offset by the third quarter 2011 transmission segment impacts described above, and a second quarter 2011 refund to transmission wholesale customers, as compared to a recovery from those customers in 2010, primarily impacting CL&P.

CL&P s third quarter 2011 distribution segment earnings were $3.1 million higher than the third quarter of 2010 due primarily to the impact of the 2010 distribution rate case decision that was effective July 1, 2010 and included an incremental $38.5 million annualized rate increase effective July 1, 2011, partially offset by a 2.1 percent decrease in retail electric sales, higher pension and healthcare costs, higher depreciation and property taxes, and the allocation of the net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010.

For the first nine months of 2011, CL&P s distribution segment earnings were $28 million higher than the same period of 2010 due primarily to the impacts of the rate case decision described above, lower uncollectibles expense, and lower income taxes, partially offset by higher pension and healthcare costs, depreciation and property taxes. For the twelve months ended September 30, 2011, CL&P s distribution segment regulatory ROE was 10.3 percent and for 2011, we expect it to be approximately 9 percent.

PSNH s third quarter 2011 distribution segment earnings were $2.8 million lower than the third quarter of 2010 due primarily to lower revenues attributable to a 2.6 percent decrease in retail electric sales and a small net decrease in the distribution rate effective July 1, 2011, higher income taxes, higher property taxes, and the allocation of the net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010, partially offset by lower operations and maintenance costs and higher generation-related earnings.

For the first nine months of 2011, PSNH s distribution segment earnings were $6.6 million higher than the same period of 2010 due primarily to higher revenues resulting from the permanent distribution rate increase effective July 1, 2010, higher generation-related earnings, and lower credits to customers in the stranded cost recovery charge. Partially offsetting these impacts was the absence of the 2010 favorable impact of the distribution rate case settlement, which allowed for the recovery of certain actual expenses retroactive to August 1, 2009, higher operations and maintenance costs, higher property taxes, and higher income taxes. For the twelve months ended September 30, 2011, PSNH s distribution segment regulatory ROE was 10.2 percent and for 2011, we expect it to be approximately 9 percent.

WMECO s third quarter 2011 distribution segment earnings were $0.9 million lower than the third quarter of 2010 due primarily to a $5.3 million pre-tax charge to establish a reserve related to a wholesale billing adjustment, higher amortization and income taxes, and the allocation of the net losses on equity securities held in the NU supplemental benefit trust, as compared to net gains in the third quarter of 2010. Partially offsetting these impacts was the favorable impact of the distribution rate case decision effective February 1, 2011 that included an annualized rate increase of $16.8 million and sales decoupling, and lower operations and maintenance costs.

For the first nine months of 2011, WMECO s distribution segment earnings were $3.6 million higher than the same period of 2010 due primarily to the impact of the distribution rate case decision effective February 1, 2011 and lower operations and maintenance costs, partially offset by the $5.3 million pre-tax charge described above, higher depreciation and amortization, and higher income taxes. For the twelve months ended September 30, 2011, WMECO s distribution segment regulatory ROE was 6.5 percent and for 2011, we expect it to be 8 percent.

Yankee Gas recorded a net loss of $3 million in the third quarter 2011 compared to a net loss of $2.9 million in the third quarter of 2010. Higher revenues and lower interest expense were essentially offset by higher operations and maintenance costs, higher depreciation and amortization, and higher property taxes.

For the first nine months of 2011, Yankee Gas earnings were $4.6 million higher than the same period of 2010 due primarily to higher revenues resulting from a 15.7 percent increase in total firm natural gas sales, lower income taxes, lower uncollectibles expense, and higher AFUDC earnings related to the WWL project capital expenditures. These favorable impacts were partially offset by higher operations and maintenance expenses, higher depreciation, and higher property taxes. For the twelve months ended September 30, 2011, Yankee Gas regulatory ROE was 9.9 percent and for 2011, we expect it to be 9 percent.

On August 28, 2011, Tropical Storm Irene caused extensive damage to NU s distribution system resulting in restoration costs of approximately $142 million. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut. The magnitude of the storm s cost and damage met the criteria for specific cost recovery in Connecticut, New Hampshire, and Massachusetts and as a result, the storm costs had no material impact on the results of operations of CL&P, PSNH or WMECO. A number of governmental inquiries have been opened in Connecticut to review the response of utilities and other entities to the storm. We believe our response was sound and prudent. CL&P will seek recovery of deferred storm costs through the appropriate regulatory recovery process.

On October 29, 2011, a snowstorm delivered high winds and heavy snowfall across our service territory, causing significant damage to our distribution and transmission systems. Approximately 1.2 million NU customers were without power at the peak of the outages, with approximately 830,000 of those customers in Connecticut, approximately 240,000 of those customers in New Hampshire, and approximately 140,000 of those customers in Massachusetts. In terms of customer outages, this was the largest in CL&P s history, surpassing Tropical Storm Irene, the third largest in PSNH s history, following the December 2008 ice storm and the February 2010 wind storm, and the largest in WMECO's history. As a result of the magnitude of the damage, we anticipate the costs of restoring service will approximate or exceed those of Tropical Storm Irene. We expect such costs to meet the criteria for recovery in Connecticut, New Hampshire, and Massachusetts and we do not expect the storm to have a material impact to the results of operations of CL&P, PSNH or WMECO. Each operating company will seek recovery of these anticipated deferred storm costs through its applicable regulatory recovery process.

For the distribution segment of our Regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric GWh sales as well as total sales and percentage changes and Yankee Gas firm natural gas sales and percentage changes in million cubic feet for the third quarter and first nine months of 2011, as compared to the same period in 2010 on an actual and weather normalized basis (using a 30-year average) is as follows:

	For the Three Months Ended September 30, 2011 Compared to 2010								
	CL&P		PSNH		WMECO		Total Electric		
Electric	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Decrease	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase	Sales (GWh)	Percentage Decrease	Wea Norm Perc Incr (Dec

Residential	(4.0)%	1.4%	(4.9)%	0.1%	(3.0)%	1.7%	4,041	4,213	(4.1)%
Commercial	(0.1)%	3.8%	(1.0)%	3.4%	1.0%	4.3%	3,928	3,934	(0.2)%
Industrial	(2.2)%	0.6%	(0.6)%	4.8%	(1.3)%	1.0%	1,199	1,218	(1.6)%
Other	(1.9)%	(1.9)%	(5.0)%	(5.0)%	1.9%	1.9%	78	79	(1.9)%
Total	(2.1)%	2.3%	(2.6)%	2.3%	(1.1)%	2.6%	9,246	9,444	(2.1)%

	For the Nine Months Ended September 30, 2011 Compared to 2010									
	CL&P		PSNH		WMECO		Total Electric			
Electric	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Sales (GWh)		Percentage Increase/ (Decrease)	W No Pe In (D
Residential	0.7%	0.5%	(0.3)%	(0.3)%	1.5%	1.2%	11,392	11,329	0.6%	
Commercial	(0.9)%	0.3%	0.2 %	1.2%	(1.5)%	(0.4)%	10,934	11,010	(0.7)%	
Industrial	(1.3)%	0.1%	(0.5)%	1.6%	(0.1)%	1.0%	3,352	3,382	(0.9)%	
Other	(0.4)%	(0.4)%	(5.2)%	(5.2)%	0.1%	0.1%	239	240	(0.7)%	
Total	(0.2)%	0.4%	(0.2)%	0.6%	-	0.5%	25,917	25,961	(0.2)%	

Firm Natural Gas	For the Three Months Ended September 30, 2011 Compared to 2010 Sales (million cubic feet) (1)		Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	For the Nine Months Ended September 30, 2011 Compared to 2010 Sales (million cubic feet) (1)		Percentage Increase	Weather Normalized Percentage Increase/ (Decrease)
Residential	805	942	(14.5)%	(14.6)%	9,599	8,705	10.3%	(3.3)%
Commercial	2,172	2,040	6.4%	6.4%	12,570	10,080	24.7%	12.3%
Industrial	3,374	3,049	10.7%	10.7%	12,046	10,775	11.8%	8.8%
Total	6,351	6,031	5.3%	5.2%	34,215	29,560	15.7%	6.3%
Total, Net of Special Contracts (2)	4,204	3,933	6.9%	6.8%	27,593	23,207	18.9%	6.8%

(1)

The 2010 sales volumes for commercial customers have been adjusted to conform to current year presentation.

(2)

Special contracts are unique to the customers who take service under such an arrangement and generally specify the amount of distribution revenue to be paid to Yankee Gas regardless of the customer's usage.

For the third quarter of 2011, actual retail electric sales for all three electric companies were lower than the same period in 2010 due to milder weather in the summer of 2011, compared with warmer than normal weather in the summer of 2010. In 2011, cooling degree days in Connecticut and Western Massachusetts were 15 percent lower than last year and in New Hampshire, cooling degree days were 25 percent lower than last year. On a weather normalized basis, our retail electric sales for all three electric companies were higher than 2010. For WMECO, the fluctuations in retail electric sales no longer impact earnings as the DPU approved a sales decoupling plan effective February 1, 2011. Under this decoupling plan, WMECO now has an established level of baseline distribution delivery service revenues of $125.6 million that it is able to recover, which effectively breaks the relationship between KWhs consumed by customers and revenues recognized.

Through the first nine months of 2011, actual retail electric sales for CL&P and PSNH were lower than the same period in 2010 and for WMECO, actual retail electric sales were essentially unchanged. The primary reason for the decline in sales in 2011 when compared to 2010 was a lower number of cooling degree days in the second and third quarters of 2011 for all three electric companies. On a weather normalized basis, our retail electric sales for the first nine months of 2011 were higher than they were in the same period in 2010, although the results varied by electric company and customer class. Our commercial and industrial electric sales continue to be negatively impacted by utilization of distributed generation and conservation programs.

Our firm natural gas sales are subject to many of the same influences as our retail electric sales, but have benefitted from migration of interruptible customers switching to firm rates and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in the third quarter of 2011 and for the first nine months of 2011 were 5.3 percent higher and 15.7 percent higher than the same periods in 2010, respectively. Colder weather, especially in the first quarter of 2011, was a contributing factor to the higher sales. Heating degree days for the first nine months of 2011 in Connecticut were 21.5 percent higher than the same period in 2010 and 1.6 percent above normal. On a weather normalized basis, actual firm natural gas sales in the third quarter of 2011 were 5.2 percent higher than last year, and for the first nine months of 2011, actual firm natural gas sales were 6.3 percent higher than the same period in 2010.

Our expense related to uncollectible receivable balances (our uncollectibles expense) is influenced by the economic conditions of our region. Fluctuations in our uncollectibles expense are mitigated from an earnings perspective because a portion of the total uncollectibles expense for each of the electric distribution companies is allocated for recovery to the respective company s energy supply rate and recovered through its tariffs. Additionally, for CL&P and Yankee Gas, write-offs of uncollectible receivable balances attributable to qualified customers under financial or medical duress (hardship customers) are fully recovered through their respective tariffs. For the third quarter of 2011, our total pre-tax uncollectibles expense that impacts earnings was $1.8 million, as compared to $5.2 million in the third quarter of 2010. For the first nine months of 2011, our total pre-tax uncollectibles expense that impacts earnings was $8.9 million, as compared to $18 million for the same period of 2010. The improvement in 2011 uncollectibles expense was due primarily to continued enhanced accounts receivable collection efforts and credit monitoring.

NU Parent and Other Companies: NU parent and other companies (which includes our competitive businesses held by NU Enterprises) recorded net expenses of $6.5 million, or $0.03 per share, in the third quarter of 2011 and $20.5 million, or $0.12 per share, in the first nine months of 2011, compared with net expenses of $0.4 million, or less than $0.01 per share, in the third quarter of 2010 and earnings of $0.7 million, or less than $0.01 per share, in the first nine months of 2010. Excluding merger-related costs of $0.6 million, or less than $0.01 per share, and $10.1 million, or $0.06 per share, NU parent and other companies recorded net expenses of $5.9 million, or $0.03 per share, and $10.4 million, or $0.06 per share, in the third quarter and first nine months of 2011, respectively. For the three and nine months ended September 30, 2011, our competitive businesses' earnings decreased by $2.8 million and $10.1 million, respectively, when compared to the same periods in 2010, as we continue to wind down the businesses.

Future Outlook

EPS Guidance: Following is a summary of our projected 2011 EPS by business, which also reconciles consolidated diluted EPS to the non-GAAP financial measure of EPS by business. Non-GAAP EPS by business also excludes a $0.20 per share charge related to projected non-recurring merger costs we expect to incur relating to financial advisor costs, legal, accounting and consulting fees and other merger-related costs, which will affect NU parent and other companies' results. The number of outstanding NU common shares used to calculate this guidance was approximately 177 million shares.

	2011 EPS Range			
(Approximate amounts)		**Low**		**High**
Diluted EPS (GAAP)	$	2.10	$	2.20
Regulated Companies:				
Distribution Segment	$	1.30	$	1.35
Transmission Segment		1.05		1.10
Total Regulated Companies		2.35		2.45
NU Parent and Other Companies		(0.05)		(0.05)
Non-GAAP EPS	$	2.30	$	2.40
Merger-Related Costs		(0.20)		(0.20)
Diluted EPS (GAAP)	$	2.10	$	2.20

The 2011 EPS projection reflects operations on a stand-alone basis in 2011, although our pending merger with NSTAR is expected to close late in the fourth quarter of 2011 or early 2012. The 2011 distribution and transmission earnings guidance reflects the impact of a higher rate base as well as $1.2 billion of projected capital expenditures in 2011.

Liquidity

Consolidated: Cash and cash equivalents totaled $16.7 million as of September 30, 2011, compared with $23.4 million as of December 31, 2010.

On September 13, 2011, PSNH issued $160 million of first mortgage bonds that will mature on September 1, 2021. The bonds carry a coupon of 3.20 percent. The net proceeds were used to repay short-term borrowings previously incurred in the ordinary course of business and for general capital purposes.

On September 16, 2011, WMECO issued $100 million of unsecured senior notes that will mature on September 15, 2021. The notes carry a coupon of 3.50 percent. The net proceeds were used to repay short-term borrowings previously incurred in the ordinary course of business.

On October 24, 2011, CL&P issued $120.5 million of PCRBs carrying a coupon of 4.375 percent that will mature on September 1, 2028 and $125 million of PCRBs carrying a coupon of 1.25 percent that mature on September 1, 2028 and are subject to mandatory tender on September 3, 2013. The proceeds of CL&P s issuances were used to refund $245.5 million of PCRBs that carried a coupon of 5.85 percent and had a maturity date of September 1, 2028. The refinancing is expected to reduce interest costs by approximately $7.5 million in 2012.

No additional long-term debt issuances are expected for the remainder of 2011.

Cash flows provided by operating activities in the first nine months of 2011 totaled $837.2 million, compared with operating cash flows of $647.9 million in the first nine months of 2010 (all amounts are net of RRB payments, which are included in financing activities on the accompanying unaudited condensed consolidated statements of cash flows). The improved cash flows were due primarily to the impact of the CL&P and PSNH 2010 distribution rate case decisions that were effective July 1, 2010 (the CL&P July 1, 2010 rate case increase was deferred from customer bills until January 1, 2011), the WMECO distribution rate case decision that was effective February 1, 2011, and a net positive cash flow impact of approximately $156 million largely attributable to accelerated depreciation tax benefits. Offsetting these benefits was a contribution of approximately $124 million made into the NU Pension Plan in the first nine months of 2011 and payments of approximately $13.1 million made in the first nine months of 2011 for merger-related costs.

We now project 2011 cash flows provided by operating activities of approximately $800 million to $850 million, net of RRB payments, down from the $900 million to $950 million we had previously announced. The decline is due primarily to the preliminary cost estimates of approximately $142 million associated with Tropical Storm Irene that are expected to be paid by the end of 2011. Those cash flows also reflect approximately $145 million of contributions to the NU Pension Plan, the last $19 million payment of which was made in October 2011. Those cash flows are likely to decrease due to the anticipated restoration costs of the October 29, 2011 snowstorm, which resulted in more outages than Tropical Storm Irene.

A summary of the current credit ratings and outlooks by Moody's, S&P and Fitch for senior unsecured debt of NU parent and WMECO and senior secured debt of CL&P and PSNH is as follows:

	Moody's		**S&P**		**Fitch**	
	Current	**Outlook**	**Current**	**Outlook**	**Current**	**Outlook**
NU parent	Baa2	Stable	BBB	Watch-Positive	BBB	Watch-Positive
CL&P	A2	Stable	A-	Watch-Positive	A-	Positive
PSNH	A3	Stable	A-	Watch-Positive	A-	Stable
WMECO	Baa2	Stable	BBB+	Watch-Positive	BBB+	Stable

We paid common dividends of $145.9 million in the first nine months of 2011, compared with $135.3 million in the first nine months of 2010. The increase reflects an approximately 7.3 percent increase in our common dividend that took effect in the first quarter of 2011. On October 11, 2011, our Board of Trustees declared a quarterly common dividend payable on December 30, 2011 to shareholders of record as of November 10, 2011. The amount of the quarterly common dividend will depend on when the pending merger with NSTAR closes. If the merger closes on or before December 30, 2011, the quarterly dividend will be $0.325 per share and if the merger does not close on or before December 30, 2011, the quarterly dividend will be $0.275 per share. The declaration is consistent with the terms of our merger agreement with NSTAR, which require that our first quarterly dividend per common share paid after the closing of the merger be increased to an amount that is at least equal, after adjusting for the exchange ratio, to NSTAR's last quarterly dividend paid prior to the closing.

In the first nine months of 2011, CL&P, PSNH, WMECO, and Yankee Gas paid $206 million, $44.1 million, $19.7 million, and $38.2 million, respectively, in common dividends to NU parent. In the first nine months of 2011, NU parent made equity contributions to PSNH, WMECO, and Yankee Gas of $20 million, $91.8 million, and $8.5 million, respectively. No equity contributions were made to CL&P in the first nine months of 2011.

Cash capital expenditures included on the accompanying unaudited condensed consolidated statements of cash flows and described in this "Liquidity" section do not include amounts incurred on capital projects but not yet paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. A summary of our cash capital expenditures by company for the first nine months of 2011 and 2010 is as follows:

	For the Nine Months Ended September 30,			
(Millions of Dollars)		**2011**		**2010**
CL&P	$	305.6	$	274.2
PSNH		167.4		218.0
WMECO		153.5		77.7
Yankee Gas		73.6		52.8
NPT		12.7		4.7
Other		36.3		50.2
Total	$	749.1	$	677.6

The increase in our cash capital expenditures was the result of higher transmission segment cash capital expenditures of $83.6 million, primarily at WMECO and NPT, as well as higher capital expenditures at Yankee Gas related to the WWL Project.

As of September 30, 2011, NU parent had $18.9 million of LOCs issued for the benefit of certain subsidiaries ($4 million for CL&P and $11.4 million for PSNH) and $30 million of short-term borrowings outstanding under its three-year $500 million unsecured revolving credit facility. The weighted-average interest rate on these short-term borrowings as of September 30, 2011 was 2.14 percent, which is based on a variable rate plus an applicable margin based on NU parent's credit ratings. NU parent had $451.1 million of borrowing availability on this facility as of September 30, 2011.

CL&P, PSNH, WMECO, and Yankee Gas maintain a joint three-year unsecured revolving credit facility in a nominal aggregate amount of $400 million. As of September 30, 2011, there were no short-term borrowings outstanding under this facility.

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 $822.5 million in the first nine months of 2011, compared with $711 million in the first nine months of 2010. These amounts included $38.4 million and $46.2 million in the first nine months of 2011 and 2010, respectively, related to our corporate service companies, NUSCO and RRR.

Regulated Companies: Capital expenditures for the Regulated companies are expected to total approximately $1.2 billion ($473 million for CL&P, $290 million for PSNH, and $269 million for WMECO) in 2011, which includes planned spending of approximately $46 million for our corporate service companies.

Transmission Segment: Transmission segment capital expenditures increased by $102.7 million in the first nine months of 2011, as compared to the same period in 2010, due primarily to increases at WMECO related to the construction of GSRP. A summary of transmission segment capital expenditures by company in the first nine months of 2011 and 2010 is as follows:

	For the Nine Months Ended September 30,	
(Millions of Dollars)	**2011**	**2010**
CL&P	$ 78.3	$ 76.7
PSNH	38.4	33.0
WMECO	153.3	64.7
NPT	13.5	6.4
Totals	$ 283.5	$ 180.8

NEEWS: GSRP, a project that involves the construction of 115 KV and 345 KV overhead lines from Ludlow, Massachusetts to Bloomfield, Connecticut, is the first, largest and most complicated project within the NEEWS family of projects. On September 13, 2011, CL&P and WMECO received the required permit from U.S. Army Corps of Engineers allowing them to commence full construction on GSRP in Connecticut and Massachusetts. The $718 million project is expected to be placed in service in late 2013.

The Interstate Reliability Project, which includes CL&P s construction of an approximately 40-mile, 345 KV overhead line from Lebanon, Connecticut to the Connecticut-Rhode Island border, is our second major NEEWS project. In August 2010, ISO-NE reaffirmed the need for a slightly modified Interstate Reliability Project, which is expected to be placed in service in late 2015. This in-service date assumes that all siting applications are filed in late 2011, with approvals received in late 2013 and construction commencing in late 2013 or early 2014. CL&P is in the process of, and on target with, submitting all permit and siting filings.

The Central Connecticut Reliability Project, which involves construction of a new 345 KV overhead line from Bloomfield, Connecticut to Watertown, Connecticut, is the third major part of NEEWS. In March 2011, ISO-NE announced that it would review the Central Connecticut Reliability Project along with other central Connecticut projects as part of a study known as the Greater Hartford Central Connecticut Study (GHCC). Preliminary need results and transmission solutions are expected in 2012.

Included as part of NEEWS are expenditures for associated reliability related projects, all of which have received siting approval and most of which are under construction. These projects began going into service in 2010 and will continue to go into service through 2013.

Through September 30, 2011, CL&P and WMECO have capitalized $118.2 million and $266.8 million, respectively, in costs associated with NEEWS, of which $19.5 million and $129.9 million, respectively, were capitalized in the first nine months of 2011. The total expected cost of NU s share of NEEWS is approximately $1.3 billion, of which $646 million and $616 million relate to CL&P and WMECO, respectively.

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

Under the terms of the TSA, which was accepted by the FERC without modification in February 2011, NPT will sell to Hydro Renewable Energy 1,200 MW of firm electric transmission rights over the Northern Pass for a 40-year term and charge cost-based rates. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project, and upon commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent. The TSA rates will be based on a deemed capital structure for NPT of 50 percent debt and 50 percent equity. During the development and the construction phases under the TSA, NPT will be recording non-cash AFUDC earnings. On March 18, 2011, the NHPUC filed a request with the FERC seeking rehearing on the ROE granted to Northern Pass. On August 5, 2011, FERC denied the request by the NHPUC.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE, which seeks permission to construct and maintain facilities that cross the U.S.-Canada border in New Hampshire and connect to HQ TransÉnergie's facilities in Québec. The DOE held seven meetings in New Hampshire in mid-March 2011 seeking public comment. In response to concerns raised at these meetings, NPT revised its application to request additional time during the public comment period to allow NPT to review alternative routes. On June 15, 2011, the DOE extended the scoping comment period for at least forty-five days after NPT files an alternative route with the DOE. NPT expects to submit that route later this year. Once this route has been identified, certain environmental studies will need to be completed in order to obtain DOE permits. This extended evaluation process is expected to result in the commencement of construction in 2014 and completion in the fourth quarter of 2016.

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

Distribution Segment: A summary of distribution segment capital expenditures by company for the first nine months of 2011 and 2010 is as follows:

	For the Nine Months Ended September 30,	
(Millions of Dollars)	**2011**	**2010**
CL&P:		
Basic Business	$ 117.9	$ 80.0
Aging Infrastructure	81.6	66.8
Load Growth	41.3	59.7
Total CL&P	240.8	206.5
PSNH:		
Basic Business	28.3	27.8
Aging Infrastructure	18.0	12.6
Load Growth	16.9	16.1
Total PSNH	63.2	56.5
WMECO:		
Basic Business	15.2	12.9
Aging Infrastructure	7.8	7.3
Load Growth	5.1	4.4
Total WMECO	28.1	24.6
Total - Electric Distribution (excluding Generation)	332.1	287.6
Yankee Gas	74.1	58.3
Other	0.6	0.3
Total Distribution	406.8	346.2
PSNH Generation:		
Clean Air Project	74.1	115.5
Other	13.6	16.5
Total PSNH Generation	87.7	132.0
WMECO Generation	6.1	5.8
Total Distribution Segment	$ 500.6	$ 484.0

For the electric distribution business, basic business includes the relocation of plant, the purchase of meters, tools, vehicles, and information technology. Aging infrastructure relates to the planned replacement of overhead lines, plant substations, transformer replacements, and underground cable replacement. Load growth includes requests for new business and capacity additions on distribution lines and substation overloads.

PSNH's Clean Air Project is a wet scrubber project that has been constructed at its Merrimack Station, the cost of which will be recovered through PSNH's ES rates under New Hampshire law. We currently expect the project to cost approximately $422 million, as compared to the previous estimate of approximately $430 million, including capitalized interest and equity returns**.** The Clean Air Project is operational and in September 2011 was placed in service at PSNH s Merrimack Station. Operational testing is underway and finalization of project activities is expected to conclude in early 2012.

On August 12, 2009, the DPU approved a stipulation agreement between WMECO and the Massachusetts Attorney General concerning WMECO's proposal, under the Massachusetts Green Communities Act, to install 6 MW of solar energy generation in its service territory at an estimated cost of $41 million by the end of 2012. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts. The full cost of this project was approximately $9.4 million. In May 2011, WMECO commenced development of a 2.2 MW solar generation facility on a 12-acre brownfield site in Springfield, Massachusetts. The project is expected to be complete by the end of 2011. WMECO is continuing its evaluation of sites suitable for construction of the remainder of the authorized 6 MW of capacity.

Yankee Gas' WWL Project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of its LNG plant, has been completed and is expected to be placed in service in November 2011. The project cost approximately $54 million, $3.6 million below the previous estimate of $57.6 million. Pursuant to the June 29, 2011 rate case decision, the WWL project will be included in Yankee Gas rate base upon entering service.

Projected Capital Expenditures and Rate Base Estimates: Excluding the impacts of the pending merger with NSTAR, a summary of the projected capital expenditures for the Regulated companies' electric transmission segment and their distribution segment (including generation) by company for 2011 through 2016, including our corporate service companies' capital expenditures on behalf of the Regulated companies, is as follows:

	Year						
(Millions of Dollars)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2012-2016 Total**
CL&P Transmission	$ 135	$ 148	$ 139	$ 210	$ 247	$ 83	$ 827
PSNH Transmission	59	76	109	176	97	23	481
WMECO Transmission	221	198	118	122	68	1	507
NPT	19	43	22	178	238	327	808
Subtotal Transmission	$ 434	$ 465	$ 388	$ 686	$ 650	$ 434	$ 2,623
CL&P Distribution:							
Basic Business	$ 153	$ 124	$ 112	$ 112	$ 113	$ 110	$ 571
Aging Infrastructure	122	100	97	86	88	90	461
Load Growth	63	60	62	73	67	72	334
Total CL&P Distribution	338	284	271	271	268	272	1,366
PSNH Distribution:							
Basic Business	45	51	48	49	50	48	246
Aging Infrastructure	30	29	24	28	26	25	132
Load Growth	27	31	37	33	40	39	180
Total PSNH Distribution	102	111	109	110	116	112	558
WMECO Distribution:							
Basic Business	19	17	16	17	18	18	86
Aging Infrastructure	12	15	16	16	16	16	79
Load Growth	5	7	7	6	6	6	32
Total WMECO Distribution	36	39	39	39	40	40	197
Subtotal Electric Distribution	$ 476	$ 434	$ 419	$ 420	$ 424	$ 424	$ 2,121
PSNH Generation:							
Clean Air Project	$ 103	$ 21	$ 2	$ -	$ -	$ -	$ 23
Other	26	14	26	29	34	34	137
Total PSNH Generation	129	35	28	29	34	34	160
CL&P Generation	-	12	22	11	-	-	45
	12	20	10	10	10	-	50

WMECO Generation														
Subtotal Generation	$	141	$	67	$	60	$	50	$	44	$	34	$	255
Yankee Gas Distribution:														
Basic Business	$	36	$	27	$	27	$	28	$	29	$	30	$	141
Aging Infrastructure		29		48		50		50		52		54		254
Load Growth		18		20		46		47		35		23		171
WWL Project		28		-		-		-		-		-		-
Total Yankee Gas Distribution	$	111	$	95	$	123	$	125	$	116	$	107	$	566
Corporate Service Companies	$	46	$	28	$	34	$	36	$	29	$	28	$	155
Total	$	1,208	$	1,089	$	1,024	$	1,317	$	1,263	$	1,027	$	5,720

Actual capital expenditures could vary from the projected amounts for the companies and periods above. Economic conditions in the northeast could impact the timing of our major capital expenditures. Most of these capital expenditure projections, including those for NPT, assume timely regulatory approval, which in most cases requires extensive review. The amounts above assume that we receive favorable responses from regulators to our proposed capital program and that our major transmission initiatives, some of which have not yet been filed with regulators, are approved in a timely manner. Delays in or denials of those approvals could reduce the levels of expenditures and associated rate base.

Based on the 2011 through 2016 projected capital expenditures, the 2011 through 2016 projected transmission, distribution and generation rate base as of December 31 of each year are as follows:

	Year					
(Millions of Dollars)	2011	2012	2013	2014	2015	2016
CL&P Transmission	$ 2,205	$ 2,151	$ 2,157	$ 2,278	$ 2,416	$ 2,444
PSNH Transmission	353	395	424	474	560	743
WMECO Transmission	382	631	725	750	874	839
NPT	-	-	-	-	16	809
Total Transmission	2,940	3,177	3,306	3,502	3,866	4,835
CL&P Distribution	2,409	2,532	2,677	2,812	2,924	3,023
PSNH Distribution	861	903	968	1,021	1,082	1,127
WMECO Distribution	419	427	440	449	462	463
Total Electric Distribution	3,689	3,862	4,085	4,282	4,468	4,613
CL&P Generation	-	9	29	35	30	27
PSNH Generation	777	730	695	689	680	683
WMECO Generation	20	34	39	44	49	45
Total Generation	797	773	763	768	759	755
Yankee Gas Distribution	733	753	792	851	974	1,031
Total	$ 8,159	$ 8,565	$ 8,946	$ 9,403	$ 10,067	$ 11,234

Transmission Rate Matters and FERC Regulatory Issues

Transmission - Wholesale Rates: Our transmission rates recover our total transmission revenue requirements, ensuring that we recover all regional and local revenue requirements for providing transmission service. These rates provide for annual reconciliations to actual costs. The difference between billed and actual costs is deferred for future recovery from, or refund to, customers. As of September 30, 2011, we were in a total net overrecovery position of $48.4 million, which will be refunded to customers in June 2012. Of this amount, CL&P, PSNH and WMECO were in an overrecovery position of $30.7 million, $4.8 million and $12.9 million, respectively.

FERC Base ROE Complaint: On September 30, 2011, several New England state attorneys general, state regulatory commissions, consumer advocates and other parties filed a joint complaint with the FERC under Section 206 and 306 of the Federal Power Act alleging that the base ROE used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by New England transmission owners, including CL&P, PSNH and WMECO, is unjust and unreasonable. The complainants assert that the current 11.14 percent rate, which became effective in 2006, is excessive due to changes in the capital markets and are seeking an order to reduce the rate to 9.2 percent, effective September 30, 2011.

On October 20, 2011, the New England transmission owners responded to the complaint, asking FERC to dismiss the complaint on the basis that the complainants failed to carry their burden of proof under Section 206 of the Federal Power Act that the existing base ROE is unjust and unreasonable. The New England transmission owners included testimony and analysis reflecting a base ROE of 11.2 percent using FERC s methodology and precedents, and thus, demonstrating that the current base ROE of 11.14 percent remains just and reasonable.

As of September 30, 2011, CL&P, PSNH, and WMECO had approximately $1.4 billion of aggregate shareholder equity invested in their transmission facilities. As a result, each 10 basis point decrease in the authorized base ROE would decrease annual combined earnings by an approximate $1.4 million.

FERC has not issued an order in this proceeding and NU cannot predict when this proceeding will be concluded, the outcome of this proceeding, or its impact on NU s financial position, results of operations or cash flows.

<u>Regulatory Developments and Rate Matters</u>

CL&P, PSNH, WMECO and Yankee Gas' rates are set by the respective state regulatory commissions and include provisions allowing for rate change mechanisms that are adjusted periodically. Other than as described below, for the third quarter and first nine months ended September 30, 2011, changes made to the CL&P, PSNH and WMECO rates did not have a material impact on their earnings, financial position, or cash flows. For further information, see "Regulatory Developments and Rate Matters" included in our 2010 Form 10-K.

Regulatory Approvals for Pending Merger with NSTAR:

Federal: On February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. On June 20, 2011, the FCC approval was extended to January 7, 2012. On July 6, 2011, we received FERC approval on the merger. We expect the Nuclear Regulatory Commission to complete its review of the merger application by the end of November 2011.

Massachusetts: On November 24, 2010, NU and NSTAR filed a joint petition requesting the DPU s approval of our pending merger. Evidentiary hearings began July 6, 2011 and were completed on July 28, 2011. Briefs in the case were filed with the DPU in September and October 2011. On July 15, 2011, the Massachusetts Department of Energy Resources filed a motion for a stay of the

proceedings. On July 21, 2011, NU and NSTAR filed a response objecting to this motion. Oral arguments on the request for a stay are scheduled for November 17, 2011. We expect a ruling on the merger from the DPU late in the fourth quarter of 2011 or early 2012.

Connecticut: In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, had petitioned the DPUC (now PURA) to reconsider its earlier view from November 2010 that it lacked jurisdiction. On June 1, 2011, the DPUC issued a final decision stating that it lacked jurisdiction over the merger. On June 30, 2011, the Office of Consumer Counsel filed an appeal of the DPUC's final decision. NRG Energy, Inc. (NRG) and the New England Power Generators Association (NEPGA) filed similar appeals in July 2011 and filed petitions with the Connecticut Superior Court in July 2011, requesting a declaratory ruling that the PURA has jurisdiction over the merger. Those appeals remain pending.

New Hampshire: On April 5, 2011, the NHPUC issued an order concluding that it does not have jurisdiction over the merger.

Maine: On May 10, 2011, the Maine Public Utilities Commission approved the merger, subject to FERC approval, which was received on July 6, 2011.

Federal:

EPA Proposed Air Toxic Standard: On March 16, 2011, the EPA issued the Mercury and Air Toxic Standards, a proposed rule that would reduce emissions of hazardous air pollutants from new and existing coal- and oil-fired electric generating units. The proposed standards would establish emission limits for mercury, arsenic and other hazardous air pollutants from coal- and oil-fired units. The proposed standards would be the first to implement a nationwide emissions standard for hazardous air pollutants across all electric generating units, providing utility companies up to four years to meet the requirements. PSNH owns and operates approximately 1,000 MW of fossil electric generating units, subject to these proposed standards, including the Merrimack, Newington and Schiller stations. We believe the Clean Air Project at our Merrimack Station, along with existing technology, positions the facility to meet the minimum requirements in the proposed standards. A review of the potential impact of this proposal on our other PSNH units is not yet complete. As a result of the large number of comments received by the EPA on the proposed standards, the EPA recently announced a 30-day extension of time to finalize the rules, and now expects to issue the final standards in mid-December 2011.

EPA Proposed NPDES Permit: PSNH maintains a NPDES permit consistent with requirements of the Clean Water Act for Merrimack Station. In 1997, PSNH filed in a timely manner for a renewal of this permit. As a result, the existing permit was administratively continued. On September 29, 2011, the EPA issued a draft renewal NPDES permit for PSNH's Merrimack Station for public review and comment. The proposed permit contains many significant conditions to future operation unprecedented in the electric utility industry. The proposed permit would require PSNH to install a closed-cycle cooling system (including cooling towers) at the station. The EPA estimated that the net present value cost to install this system and operate it over a 20-year period would be approximately $112 million.

On October 27, 2011, the EPA extended the initial 60-day period for public review and comment on the draft permit for an additional 90 days until February 28, 2012. The EPA has no set deadline to consider comments and to issue a final permit. Given the complex and unprecedented nature of many of the requirements, extensive comments to the EPA on the draft permit are anticipated from within the utility industry as well as from various environmental groups. Merrimack Station can continue to operate under its present permit pending issuance of the final permit and subsequent resolution of matters appealed by PSNH and other parties. Due to the site specific characteristics of PSNH's other fossil generating stations, we believe it is unlikely that they would have similar permit requirements imposed on them.

Connecticut CL&P:

Tropical Storm Irene: On August 28, 2011, Tropical Storm Irene caused extensive damage to CL&P s distribution system. Approximately 670,000 CL&P customers were without power at the peak of the outages. The magnitude of the storm s cost and damage met the criteria for specific cost recovery in Connecticut and as a result, the storm had no material impact on CL&P s results of operations. In September 2011, the PURA opened an inquiry into the preparations for and responses to Tropical Storm Irene by Connecticut utilities, including CL&P. Also, in September 2011, legislative hearings were held concerning responses of state utilities as well as of state and local government. We believe our response was sound and prudent. CL&P will seek recovery of deferred storm costs through the appropriate regulatory recovery process.

AMI: On August 29, 2011, PURA issued a draft decision rejecting the full deployment of AMI meters to all of CL&P s customers at this time. PURA instead indicated that CL&P should begin installing AMI meters at a more moderate pace once industry standards are developed and CL&P has selected a specific technology to install. On September 2, 2011, the Commissioner of DEEP filed a motion with PURA to suspend the proceeding while the Bureau of Energy and Technology Policy conducts a process to establish an AMI policy for Connecticut, in accordance with the state law. On September 8, 2011, PURA granted DEEP s motion and suspended its proceedings. No further schedule is available at this time from either DEEP or PURA. As a result, CL&P has removed the projected AMI capital costs of approximately $257 million from its current five-year capital program.

Connecticut - Yankee Gas:

Distribution Rates: On June 29, 2011 the DPUC (now PURA) issued a final decision in the Yankee Gas rate proceeding. On July 14, 2011, Yankee Gas filed a motion for reconsideration with the PURA in regards to certain items, including the disallowance of its proposal to reduce ADIT by the tax effect of net operating loss. On September 28, 2011, PURA issued a final decision and approved changes to the June 29, 2011 decision regarding ADIT. PURA reversed its previous determination and allowed the inclusion of a net operating loss tax asset in the calculations of average ADIT during Yankee Gas' two rate years. The changes were effective July 20, 2011 and will have the effect of raising the allowed rate base and increasing revenues by $3.3 million and $0.4 million, respectively, for the twelve months ended June 30, 2012 and by $6.7 million and $0.7 million, respectively, for the twelve months ended June 30, 2013.

New Hampshire:

ES Filing: On October 14, 2011, PSNH filed preliminary construction costs of the Clean Air Project to be included in its 2012 ES rate as the Clean Air Project was placed into service in September 2011. PSNH expects to petition the NHPUC using updated cost information in late November 2011 for a specific 2012 ES rate.

As part of this ES filing, PSNH also proposed a new ES rate for customers who are returning to PSNH ES after taking service from a competitive supplier. The proposed Alternate Default Energy Service Rate (ADE) would be based on PSNH s marginal costs plus an adder. The proposed ADE rate would be calculated based on forecasted full requirements power supply costs consistent with the power supply costs in the ES filing plus an adder equal to certain costs associated with the Clean Air Project. The proposed ADE rate would be determined annually at the same time that PSNH s ES rate is determined and would be subject to a mid-year adjustment, as is the case with the ES rate. Similar to all ES costs and revenues, the proposed ADE costs and revenues would be included in the annual ES rate reconciliation process.

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, results of operations or cash flows. 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 our 2010 Form 10-K. There have been no material changes with regard to these critical accounting policies and estimates.

Other Matters

Environmental Matters: Refer to Note 8A, "Commitments and Contingencies Environmental Matters," to the unaudited condensed consolidated financial statements for discussion of the HWP environmental remediation contingency.

Contractual Obligations and Commercial Commitments: Other than as set forth below, there have been no additional material contractual obligations identified and no material changes with regard to the contractual obligations and commercial commitments previously disclosed in our 2010 Form 10-K.

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(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Totals**
Renewable Energy Supply Contracts	$ 5.1	$ 5.1	$ 59.9	$ 60.7	$ 70.9	$ 1,263.1	$ 1,464.8

PSNH has entered into supply contracts for the purchase of electricity from renewable suppliers. Included in these amounts are payment obligations for the purchase of biomass electricity through a 20-year contract, which was approved by the NHPUC on September 2, 2011. Such contracts at PSNH extend through 2033. These obligations are not included on our consolidated balance sheets.

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

RESULTS OF OPERATIONS NORTHEAST UTILITIES AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the 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, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended September 30,				Operating Revenues and Expenses For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 1,114.9	$ 1,243.3	$ (128.4)	(10.3)%	$ 3,397.6	$ 3,694.2	$ (296.6)	(8.0)%
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	399.9	494.1	(94.2)	(19.1)	1,214.4	1,539.7	(325.3)	(21.1)
Other Operating Expenses	237.6	233.5	4.1	1.8	752.4	688.4	64.0	9.3
Maintenance	58.9	50.0	8.9	17.8	205.5	162.4	43.1	26.5
Depreciation	75.2	71.0	4.2	5.9	222.8	228.7	(5.9)	(2.6)
Amortization of Regulatory Assets, Net	36.8	50.3	(13.5)	(26.8)	88.4	51.0	37.4	73.3
Amortization of Rate Reduction Bonds	17.7	60.4	(42.7)	(70.7)	52.0	175.0	(123.0)	(70.3)
Taxes Other Than Income Taxes	85.0	84.4	0.6	0.7	252.8	244.4	8.4	3.4
Total Operating Expenses	911.1	1,043.7	(132.6)	(12.7)	2,788.3	3,089.6	(301.3)	(9.8)
Operating Income	$ 203.8	$ 199.6	$ 4.2	2.1 %	$ 609.3	$ 604.6	$ 4.7	0.8 %

Operating Revenues

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Electric Distribution	$ 878.6	$ 1,010.5	$ (131.9)	(13.1)%	$ 2,564.7	$ 2,895.0	$ (330.3)	(11.4)%
Natural Gas Distribution	59.6	59.6	-	-	318.1	304.9	13.2	4.3
Total Distribution	938.2	1,070.1	(131.9)	(12.3)	2,882.8	3,199.9	(317.1)	(9.9)
Transmission	159.1	159.4	(0.3)	(0.2)	469.4	467.2	2.2	0.5
	1,097.3	1,229.5	(132.2)	(10.8)	3,352.2	3,667.1	(314.9)	(8.6)

Total Regulated Companies												
Other and Eliminations		17.6		13.8		3.8	27.5		45.4		27.1		18.3	67.5
NU	$	1,114.9	$	1,243.3	$	(128.4)	(10.3)%	$	3,397.6	$	3,694.2	$	(296.6)	(8.0)%

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

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2011	2010	Increase/ (Decrease)	Percent	2011	2010	Increase/ (Decrease)	Percent
Retail Electric Sales in GWh	9,246	9,444	(198)	(2.1)%	25,917	25,961	(44)	(0.2)%
Firm Natural Gas Sales in Million Cubic Feet	6,351	6,031	320	5.3 %	34,215	29,560	4,655	15.7 %
Firm Natural Gas Sales (Net of Special Contracts) in Million Cubic Feet	4,204	3,933	271	6.9 %	27,593	23,207	4,386	18.9 %

Our Operating Revenues decreased for the three months ended September 30, 2011, as compared to the same period in 2010 due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($89.2 million), lower CL&P CTA revenues ($47.1 million), lower wholesale revenues ($25.2 million), lower retail other revenues ($10.2 million) and lower retail transmission revenues ($5.7 million), partially offset by higher CL&P FMCC delivery-related revenues ($16.1 million) and higher distribution other revenues ($4.2 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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A slight decrease in transmission segment revenues due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to the increased level of investment in the transmission infrastructure.

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An increase of $27.3 million in the portion of electric distribution revenues that impacts earnings due primarily to the impact of electric distribution rate case decisions received that were in effect during the third quarter of 2011, partially offset by a 2.1 percent decrease in retail electric sales due to milder weather in the summer of 2011, compared to warmer than normal weather in the summer of 2010.

Our Operating Revenues decreased for the nine months ended September 30, 2011, as compared to the same period in 2010 due primarily to:

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Lower electric distribution revenues related to the portions that are included in regulatory commission approved tracking mechanisms that recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower energy and supply-related costs ($290.4 million), lower CL&P CTA revenues ($126.4 million), lower wholesale revenues ($57 million) and lower retail other revenues ($28.9 million), partially offset by higher retail transmission revenues ($20.5 million) and higher CL&P FMCC delivery-related revenues ($13 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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An increase of $114.5 million in the portion of electric distribution revenues that impacts earnings due primarily to the impact of electric distribution rate case decisions received that were in effect during 2011. Natural gas revenues increased due primarily to an increase in sales volume related to the colder than normal weather in 2011, especially in the first quarter, as compared to 2010. Firm natural gas sales increased 15.7 percent for the nine months ended September 30, 2011, as compared to the same period in 2010. Partially offsetting the increase in natural gas revenues was a decrease in cost of fuel, as fuel costs are fully recovered in revenues from sales to our customers.

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Improved transmission segment revenues resulting from a higher level of investment in transmission infrastructure and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses. These were partially offset by a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the following:

(Millions of Dollars)	**Three Months Ended**	**Nine Months Ended**
Lower GSC supply costs and purchased power contract costs,	$ (76.6)	$ (267.4)

partially offset by higher other costs at CL&P				
ES customer migration to third party electric suppliers, and lower ES customer retail sales at PSNH		(16.2)		(46.8)
Lower basic service supply costs at WMECO		(0.7)		(8.3)
Other		(0.7)		(2.8)
	$	(94.2)	$	(325.3)

Other Operating Expenses

Other Operating Expenses increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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Higher NU parent and other companies expenses ($5.5 million) due primarily to higher costs at NU s unregulated electrical contracting business related to an increased level of work in 2011 ($7.9 million), partially offset by lower environmental costs at HWP ($1.6 million).

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Lower costs that are recovered through distribution tracking mechanisms that have no earnings impact ($4.6 million), such as retail transmission, RMR and customer service expenses. In addition, there were lower transmission segment expenses ($3.3 million). Partially offsetting these decreases were higher electric distribution expenses ($4.4 million) and higher natural gas expenses ($1.2 million), including higher pension costs and higher administrative and general expenses.

Other Operating Expenses increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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Higher NU parent and other companies expenses ($36.1 million) were due primarily to costs related to NU s pending merger with NSTAR ($13.1 million), higher costs at NU s unregulated electrical contracting business ($11.2 million) and higher pension costs.

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Higher costs that are recovered through distribution tracking mechanisms that have no earnings impact ($5 million), such as retail transmission, RMR and customer service expenses. In addition, there were higher electric distribution expenses ($14.5 million) and higher natural gas expenses ($7.3 million), including higher pension costs and higher administrative and general expenses. Partially offsetting these increases were lower transmission segment expenses ($5.6 million).

Maintenance

Maintenance increased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 CL&P rate case decision.

Depreciation

Depreciation increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Depreciation decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to a lower depreciation rate being used at CL&P as a result of the distribution rate case decision that was effective July 1, 2010. Partially offsetting this decrease are higher depreciation rates being used at PSNH and WMECO during 2011, as compared to 2010, as a result of distribution rate case decisions that were effective during 2011 and higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to lower amortization of the SBC balance ($13.3 million) and lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($9.9 million) at CL&P. Partially offsetting these decreases were lower CTA transition costs ($46.6 million) partially offset by lower retail CTA revenue ($43.9 million) at CL&P.

Amortization of Regulatory Assets, Net, increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to lower CTA transition costs ($153 million) offset by lower retail CTA revenue ($118.2 million) at CL&P, increases in TCAM amortization ($28.5 million) and ES amortization ($11 million) at PSNH and the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes ($24 million). Partially offsetting these increases were lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes at CL&P ($28.8 million) and lower amortization of the SBC balance at CL&P ($26.3 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due to the maturity of CL&P s RRBs in December 2010 and lower principal balances on the remaining PSNH and WMECO RRBs outstanding.

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, was due primarily to an increase in property taxes related to an increase in our capital program and an increase in tax rates, offset by a decrease in the Connecticut Gross Earnings Tax primarily due to lower CTA revenues in 2011, as compared to 2010.

Interest Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Interest on Long-Term Debt	$ 57.5	$ 57.8	$ (0.3)	(0.5)%	$ 171.9	$ 173.6	$ (1.7)	(1.0)%
Interest on RRBs	2.0	4.7	(2.7)	(57.4)	6.9	17.0	(10.1)	(59.4)
Other Interest	4.4	3.4	1.0	29.4	5.9	9.8	(3.9)	(39.8)
	$ 63.9	$ 65.9	$ (2.0)	(3.0)%	$ 184.7	$ 200.4	$ (15.7)	(7.8)%

Interest Expense decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the resolution of state tax matters concerning the calculation of interest on outstanding amounts in the first quarter of 2011, which resulted in a reduction in Other Interest. In addition, NU had lower Interest on RRBs in 2011, as compared to 2010 resulting from the maturity of CL&P s RRBs in December 2010 and lower principal balances on the remaining PSNH and WMECO RRBs outstanding.

Other Income, Net

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Other Income, Net	$ 1.4	$ 10.1	$ (8.7)	(86.1)%	$ 19.1	$ 19.7	$ (0.6)	(3.0)%

Other Income, Net decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to net losses on the NU supplement benefit trust in 2011, compared to net gains in 2010.

Income Tax Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Income Tax Expense	$ 49.9	$ 41.9	$ 8.0	19.1 %	$ 157.9	$ 161.1	$ (3.2)	(2.0)%

Income Tax Expense increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to return to provision adjustments ($6.4 million) and higher items that directly impact our tax return as a result of regulatory requirements ("flow-through" items) ($0.8 million).

Income Tax Expense decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to the absence of 2010 Healthcare Act impacts ($27.6 million); partially offset by higher pre-tax earnings ($18.1 million) and return to provision adjustments ($6.4 million).

58

RESULTS OF OPERATIONS THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the 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, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended September 30,				**Operating Revenues and Expenses For the Nine Months Ended September 30,**			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 673.7	$ 789.2	$ (115.5)	(14.6)%	$ 1,955.4	$ 2,292.1	$ (336.7)	(14.7)%
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	257.6	334.2	(76.6)	(22.9)	720.2	987.6	(267.4)	(27.1)
Other Operating Expenses	128.4	127.8	0.6	0.5	401.9	382.9	19.0	5.0
Maintenance	36.0	21.1	14.9	70.6	118.7	75.7	43.0	56.8
Depreciation	39.7	38.1	1.6	4.2	117.6	133.5	(15.9)	(11.9)
Amortization of Regulatory Assets, Net	15.7	33.0	(17.3)	(52.4)	48.7	55.3	(6.6)	(11.9)
Amortization of Rate Reduction Bonds	-	43.8	(43.8)	(100.0)	-	126.0	(126.0)	(100.0)
Taxes Other Than Income Taxes	58.6	59.8	(1.2)	(2.0)	169.8	168.0	1.8	1.1
Total Operating Expenses	536.0	657.8	(121.8)	(18.5)	1,576.9	1,929.0	(352.1)	(18.3)
Operating Income	$ 137.7	$ 131.4	$ 6.3	4.8 %	$ 378.5	$ 363.1	$ 15.4	4.2 %

Operating Revenues

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

	For the Three Months Ended September 30,				**For the Nine Months Ended September 30,**			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Retail Electric Sales in GWh	6,159	6,293	(134)	(2.1)%	17,185	17,221	(36)	(0.2)%

CL&P's Operating Revenues decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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A $142.3 million decrease in electric distribution revenues related to the portions that are included in PURA approved tracking mechanisms that track and recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($79.6 million), lower CTA revenues ($47.1 million), lower wholesale revenues ($25.4 million) and lower retail other revenues ($10.8 million). These lower revenues were partially offset by higher delivery-related FMCC revenues ($16.1 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods. The lower GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers in the third quarter of 2011, as compared to the third quarter of 2010.

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A $5.6 million decrease in transmission segment revenues due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to the increased level of investment in the transmission infrastructure.

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An increase of $32.3 million in the portion of electric distribution revenues that impacts earnings due primarily to the retail rate increase effective January 1, 2011, partially offset by a 2.1 percent decrease in retail electric sales volume in the third quarter of 2011, as compared to the third quarter of 2010.

CL&P's Operating Revenues decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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A $416.3 million decrease in electric distribution revenues related to the portions that are included in PURA approved tracking mechanisms that track and recover certain incurred costs and do not impact earnings. The tracked electric distribution revenues decreased due primarily to lower GSC and supply-related FMCC revenues ($251 million), lower CTA revenues ($126.4 million), lower wholesale revenues ($59.9 million) and lower retail other revenues ($28.9 million). These lower revenues were partially offset by higher retail transmission revenues ($15.5 million), higher delivery-related FMCC revenues ($13 million) and higher other revenues ($5.2 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 lower GSC and supply-related FMCC revenues were due primarily to lower customer rates resulting from lower average supply prices and additional customer migration to third party electric suppliers for the nine months ended September 30, 2011, as compared to the same period in 2010.

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A $11.4 million decrease in transmission segment revenues due primarily to a refund to transmission wholesale customers, compared to a recovery from those customers in 2010. The transmission rates provide for an annual reconciliation and recovery or refund of projected costs to actual costs. The difference between projected costs and actual costs are recovered from, or refunded to, customers each year. This decrease was partially offset by increased transmission segment revenues due to the increased level of investment in the transmission infrastructure.

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An increase of $90.9 million in the portion of electric distribution revenues that impacts earnings for the nine months ended September 30, 2011, as compared to the same period in 2010 due primarily to the retail rate increase effective January 1, 2011.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the following:

(Millions of Dollars)	Three Months Ended	Nine Months Ended
GSC Supply Costs	$ (85.8)	$ (260.9)
Purchased Power Contracts	(15.4)	(49.1)
Deferred Fuel Costs	0.6	9.0
Other	24.0	33.6
	$ (76.6)	$ (267.4)

The decrease in GSC supply costs was due primarily to lower average supply prices and additional customer migration to third party electric suppliers for the three and nine months ended September 30, 2011, as compared to the same periods in 2010. 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. These costs are included in PURA approved tracking mechanisms and do not impact earnings.

Other Operating Expenses

Other Operating Expenses increased for the nine months ended September 30, 2011, as compared to the same period in 2010, as a result of higher distribution segment expenses ($13.7 million) mainly as a result of higher administrative and general expenses, including higher pension costs and higher costs that are recovered through distribution tracking mechanisms and have no earnings impact ($12.5 million). Partially offsetting these increases were lower transmission segment expenses ($5.2 million).

Maintenance

Maintenance increased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the partial amortization in 2011 of the allowed regulatory deferral, which was recorded in maintenance expense in 2010, as a result of the June 30, 2010 rate case decision.

Depreciation

Depreciation increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher utility plant balances resulting from completed construction projects placed into service.

Depreciation decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to a lower depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010, partially offset by higher utility plant balances resulting from completed construction projects placed into service.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to lower amortization of the SBC balance ($13.3 million) and lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($9.9 million). Partially offsetting these decreases were lower CTA transition costs ($46.6 million) offset by lower retail CTA revenue ($43.9 million).

Amortization of Regulatory Assets, Net, decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due to lower amortization related to the previously deferred unrecovered stranded generation costs related to income taxes ($28.8 million) and lower amortization of the SBC balance ($26.3 million). Partially offsetting these decreases were lower CTA transition costs ($153 million) offset by lower retail CTA revenue ($118.2 million), and the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes.

Amortization of Rate Reduction Bonds

Amortization of RRBs decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due to the maturity of RRBs in December 2010.

Interest Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Interest on Long-Term Debt	$ 33.3	$ 33.7	$ (0.4)	(1.2) %	$ 100.1	$ 100.9	$ (0.8)	(0.8) %
Interest on RRBs	-	1.5	(1.5)	(100.0)	-	6.8	(6.8)	(100.0)
Other Interest	1.9	1.5	0.4	26.7	(0.8)	4.7	(5.5)	(a)

	$	35.2	$	36.7	$	(1.5)	(4.1) %		$	99.3	$	112.4	$	(13.1)	(11.7) %

(a) Percent greater than 100 percent not shown since it is not meaningful.

Interest Expense decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the resolution of state tax matters concerning the calculation of interest on outstanding amounts, which resulted in a reduction in Other Interest in the first quarter of 2011, and the absence of Interest on RRBs in 2011 as CL&P's RRBs matured in December 2010.

Other Income/(Loss), Net

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Other Income/(Loss), Net	$ (2.4)	$ 6.9	$ (9.3)	(a)%	$ 4.3	$ 12.6	$ (8.3)	(65.9)%

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

Other Income/(Loss), Net decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to net losses on the NU supplement benefit trust in 2011, compared to net gains in 2010.

Income Tax Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Income Tax Expense	$ 33.6	$ 32.6	$ 1.0	3.1 %	$ 100.1	$ 101.7	$ (1.6)	(1.6)%

Income Tax Expense increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to return to provision adjustments.

Income Tax Expense decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to the absence of 2010 Healthcare Act impacts ($14.4 million); partially offset by higher pre-tax earnings ($10.2 million), higher flow-through impacts ($1.4 million) and return to provision adjustments ($0.9 million).

LIQUIDITY

CL&P had cash flows provided by operating activities in the first nine months of 2011 of $486.6 million, compared with operating cash flows of $343.2 million in the first nine months of 2010 (first nine months 2010 amounts are net of RRB payments, which are included in financing activities). The improved cash flows in 2011 were due primarily to the impact of the DPUC (now PURA) July 1, 2010 distribution rate case decision, which increased CL&P s customer rates effective January 1, 2011, and a net positive cash flow impact of $96.9 million largely attributable to accelerated depreciation tax benefits. We now project 2011 cash flows provided by operating activities of approximately $500 million to $550 million, down from the $600 million to $650 million we had previously announced. The decline is due primarily to the preliminary cost estimates of approximately $130 million associated with Tropical Storm Irene that are expected to be paid by the end of 2011. Those cash flows are likely to decrease due to the anticipated restoration costs of the October 29, 2011 snowstorm, which resulted in more outages to CL&P's service territory than Tropical Storm Irene.

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 $305.6 million for the nine months ended September 30, 2011, compared with $274.2 million for the nine months ended September 30, 2010.

Proceeds from Sale of Assets in the first nine months of 2011 of $46.8 million included on the accompanying unaudited condensed consolidated statement of cash flows related to the sale of certain CL&P transmission assets.

Financing activities for the nine months ended September 30, 2011 included $206 million in common dividends paid to NU parent.

RESULTS OF OPERATIONS PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

The following table provides the amounts and variances in operating revenues and expense line items for the 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, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended September 30,				Operating Revenues and Expenses For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 259.6	$ 277.0	$ (17.4)	(6.3)%	$ 769.3	$ 773.9	$ (4.6)	(0.6)%
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	77.9	94.1	(16.2)	(17.2)	234.4	281.2	(46.8)	(16.6)
Other Operating Expenses	52.6	53.1	(0.5)	(0.9)	163.3	172.3	(9.0)	(5.2)
Maintenance	16.2	21.0	(4.8)	(22.9)	64.8	62.6	2.2	3.5
Depreciation	18.4	17.5	0.9	5.1	54.4	49.4	5.0	10.1
Amortization of Regulatory Assets/(Liabilities), Net	17.3	14.5	2.8	19.3	35.3	(2.8)	38.1	(a)
Amortization of Rate Reduction Bonds	13.6	12.8	0.8	6.3	39.8	37.5	2.3	6.1
Taxes Other Than Income Taxes	15.1	14.2	0.9	6.3	44.0	40.6	3.4	8.4
Total Operating Expenses	211.1	227.2	(16.1)	(7.1)	636.0	640.8	(4.8)	(0.7)
Operating Income	$ 48.5	$ 49.8	$ (1.3)	(2.6)%	$ 133.3	$ 133.1	$ 0.2	0.2 %

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

Operating Revenues:

PSNH's retail electric sales were as follows:

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Retail Electric Sales in GWh	2,091	2,147	(56)	(2.6)%	5,924	5,934	(10)	(0.2)%

PSNH's Operating Revenues decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

.

A $16.6 million decrease in distribution revenues related to the portions that are included in NHPUC approved tracking mechanisms that recover certain incurred costs and do not impact earnings. This decrease primarily related to lower purchased fuel and power costs ($7.9 million), related to a slight increase ES customer migration to third party electric suppliers and lower retail sales, lower retail transmission revenues ($7.3 million) and lower stranded cost recoveries ($2.9 million). These lower revenues were offset by higher wholesale revenues ($1.5 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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A decrease of $2.1 million in the portion of electric distribution revenues that impacts earnings in the third quarter of 2011, as compared to the third quarter of 2010 due primarily to a 2.6 percent decrease in retail electric sales.

PSNH's Operating Revenues decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

.

A $29.4 million decrease in distribution revenues related to the portions that are included in NHPUC approved tracking mechanisms that recover certain incurred costs and do not impact earnings. This decrease primarily related to lower purchased fuel and power costs ($28 million), related to a slight increase ES customer migration to third party electric suppliers, and lower stranded cost recoveries ($2.9 million). These lower revenues were offset by higher wholesale revenues ($4.6 million) and higher retail transmission revenues ($3.8 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

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An increase of $20.7 million in the portion of electric distribution revenues that impacts earnings for the nine months ended September 30, 2011, as compared to the same of 2010 due primarily to the retail rate increase effective July 1, 2010.

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A $4.2 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to a slight increase in the level of ES customer migration to third party electric suppliers and lower retail sales for PSNH's remaining ES customers.

Other Operating Expenses

Other Operating Expenses decreased for the nine months ended September 30, 2011, as compared to the same period in 2010, as a result of lower retail transmission expenses ($6.8 million) and lower administrative and general expenses related to PSNH s generation business ($1.1 million).

Maintenance

Maintenance decreased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to lower distribution segment routine maintenance expenses.

Maintenance increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher distribution segment routine maintenance expenses ($5.2 million), partially offset by lower generation maintenance costs ($2.3 million).

Depreciation

Depreciation increased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to a higher depreciation rate being used as a result of the distribution rate case decision that was effective July 1, 2010 and higher utility plant balances resulting from completed construction projects placed into service related to PSNH's capital programs.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of Regulatory Assets/(Liabilities), Net increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to an increase in TCAM amortization ($11.8 million), partially offset by a decrease in ES amortization ($8.2 million).

Amortization of Regulatory Assets/(Liabilities), Net increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to an increase in ES amortization ($28.5 million) and TCAM amortization ($11 million) and the absence in 2011 of the impact of the write-off and deferral of income taxes related to the 2010 Healthcare Act ($5.3 million).

Taxes Other Than Income Taxes

The increase in Taxes Other Than Income Taxes for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, was due primarily to an increase in property taxes related to an increase in PSNH s capital program and an increase in the tax rate**.**

Interest Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Interest on Long-Term Debt	$ 8.5	$ 9.0	$ (0.5)	(5.6)%	$ 25.4	$ 27.7	$ (2.3)	(8.3)%
Interest on RRBs	1.5	2.3	(0.8)	(34.8)	5.0	7.5	(2.5)	(33.3)
Other Interest	0.4	0.2	0.2	100.0	0.8	0.6	0.2	33.3
	$ 10.4	$ 11.5	$ (1.1)	(9.6)%	$ 31.2	$ 35.8	$ (4.6)	(12.8)%

Interest Expense decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to lower Interest on Long-Term Debt, primarily related to higher AFUDC borrowed funds related to PSNH's Clean Air Project, and lower Interest on RRBs resulting from lower principal balances outstanding.

Other Income, Net

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Other Income, Net	$ 3.3	$ 3.7	$ (0.4)	(10.8)%	$ 12.1	$ 5.9	$ 6.2	(a)

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

Other Income, Net increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher AFUDC related to equity funds.

Income Tax Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Income Tax Expense	$ 15.8	$ 13.2	$ 2.6	19.7 %	$ 39.5	$ 37.0	$ 2.5	6.8 %

Income Tax Expense increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to return to provision adjustments ($1.4 million) and decreases in certain generation plant permanent tax benefits ($0.6 million).

Income Tax Expense increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings impacts ($5.5 million), higher state taxes including return to provision adjustments ($2.5 million); partially offset by the absence of 2010 Healthcare Act impacts ($6.5 million).

LIQUIDITY

PSNH had cash flows provided by operating activities in the first nine months of 2011 of $161 million, compared with operating cash flows of $139 million in the first nine months of 2010 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to the impact of PSNH s 2010 distribution rate case settlement, which increased PSNH rates effective July 1, 2010, a net positive cash flow impact of $19.4 million largely attributable to accelerated depreciation tax benefits, and the absence in the first nine months of 2011 of payments related to the February 2010 severe wind storm, for which the costs were deferred. In addition, in 2011 PSNH began collecting on the ES tracking mechanism's 2010 underrecoveries, creating a favorable cash flow impact. Offsetting these benefits were contributions into the NU Pension Plan of $93.4 million in the first nine months of 2011, compared with contributions into the NU Pension Plan of $45 million in the first nine months of 2010.

RESULTS OF OPERATIONS WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

The following table provides the amounts and variances in operating revenues and expense line items for the 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, 2011 and 2010:

	Operating Revenues and Expenses For the Three Months Ended September 30,				Operating Revenues and Expenses For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**	**2011**	**2010**	**Increase/ (Decrease)**	**Percent**
Operating Revenues	$ 104.5	$ 103.7	$ 0.8	0.8 %	$ 309.6	$ 296.4	$ 13.2	4.5 %
Operating Expenses:								
Fuel, Purchased and Net Interchange Power	39.2	39.9	(0.7)	(1.8)	112.0	120.3	(8.3)	(6.9)
Other Operating Expenses	22.7	27.3	(4.6)	(16.8)	75.4	73.6	1.8	2.4
Maintenance	4.0	5.0	(1.0)	(20.0)	13.0	14.8	(1.8)	(12.2)
Depreciation	6.7	5.8	0.9	15.5	19.6	17.7	1.9	10.7
Amortization of Regulatory Assets, Net	3.4	2.7	0.7	25.9	4.6	0.4	4.2	(a)
Amortization of Rate Reduction Bonds	4.1	3.8	0.3	7.9	12.3	11.5	0.8	7.0
Taxes Other Than Income Taxes	4.6	4.3	0.3	7.0	13.4	12.5	0.9	7.2
Total Operating Expenses	84.7	88.8	(4.1)	(4.6)	250.3	250.8	(0.5)	(0.2)
Operating Income	$ 19.8	$ 14.9	$ 4.9	32.9 %	$ 59.3	$ 45.6	$ 13.7	30.0 %

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

Operating Revenues

WMECO's retail electric sales were as follows:

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2011	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Retail Electric Sales in GWh	999	1,009	(10)	(1.1)%	2,817	2,818	(1)	- %

WMECO's Operating Revenues increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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A $4 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

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A decrease of $2.9 million in the portion of electric distribution revenues that impacts earnings due primarily to the establishment of a reserve related to a wholesale billing adjustment ($5 million), partially offset by the retail rate increase effective February 1, 2011 ($2.1 million).

WMECO's Operating Revenues increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to:

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A $9.3 million improvement in transmission segment revenues resulting from a higher level of investment in this segment and the recovery of higher overall expenses, which are tracked and result in a related increase in revenues. The increase in expenses is directly related to the increase in transmission plant, including costs associated with higher property taxes, depreciation and operation and maintenance expenses.

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An increase of $2.9 million in the portion of electric distribution revenues that impacts earnings due primarily to the retail rate increase effective February 1, 2011 ($8 million), partially offset by the establishment of a reserve related to a wholesale billing adjustment made in the third quarter of 2011 ($5 million).

Fuel, Purchased and Net Interchange Power

Fuel, Purchased and Net Interchange Power decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, related to lower basic service supply costs, due primarily to lower supplier contract rates, and lower purchased power contract costs. Partially offsetting these decreases was an increase in the deferral of excess basic service revenue over basic service expense. The basic service supply costs are the contractual amounts WMECO must pay to various suppliers that serve this load after winning a competitive solicitation process.

To the extent these costs do not match revenues collected from customers, the DPU allows the difference to be deferred for future collection or refunded to customers.

Other Operating Expenses

Other Operating Expenses decreased for the three months ended September 30, 2011, as compared to the same period in 2010, as a result of lower transmission expenses ($1.8 million), a decrease in bad debt expense ($1.5 million) and lower C&LM expenses ($0.4 million). These costs are recovered through distribution tracking mechanisms and have no earnings impact.

Other Operating Expenses increased for the nine months ended September 30, 2011, as compared to the same period in 2010, as a result of an increase in C&LM expenses attributable to the Massachusetts Green Communities Act ($4.4 million), an increase in administrative and general expenses related to an increase in pension costs ($1.2 million) and higher other distribution expenses ($0.5 million). Partially offsetting these increases were a decrease in bad debt expense ($3.8 million) and lower transmission expenses ($1.3 million). These costs are recovered through distribution tracking mechanisms and have no earnings impact.

Maintenance

Maintenance decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to lower distribution segment routine overhead line expenses.

Depreciation

Depreciation increased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to a higher depreciation rate being used at WMECO as a result of the distribution rate case decision that was effective February 1, 2011 and higher utility plant balances resulting from completed construction projects placed into service related to WMECO's capital programs.

Amortization of Regulatory Assets, Net

Amortization of Regulatory Assets, Net, increased for the nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to the absence in 2011 of the impact of the 2010 Healthcare Act related to income taxes.

Other (Loss)/Income, Net

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Decrease**	**Percent**	**2011**	**2010**	**Decrease**	**Percent**
Other (Loss)/Income, Net	$ (0.7)	$ 0.7	$ (1.4)	(a)	$ 0.3	$ 1.5	$ (1.2)	(80.0)%

(a) Percent greater than 100 percent not shown since it is not meaningful.

Other (Loss)/Income, Net decreased for the three and nine months ended September 30, 2011, as compared to the same periods in 2010, due primarily to net losses on the NU supplement benefit trust in 2011, compared to net gains in 2010.

Income Tax Expense

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
(Millions of Dollars)	**2011**	**2010**	**Increase**	**Percent**	**2011**	**2010**	**Increase**	**Percent**
Income Tax Expense	$ 4.6	$ 2.7	$ 1.9	70.4 %	$ 16.0	$ 12.6	$ 3.4	27.0 %

Income Tax Expense increased for the three months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings ($1.1 million) and return to provision adjustments ($0.5 million).

Income Tax Expense increased for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher pre-tax earnings ($5.1 million) and return to provision adjustments ($0.5 million), partially offset by the absence of 2010 Healthcare Act impacts ($2.8 million).

LIQUIDITY

WMECO had cash flows provided by operating activities in the first nine months of 2011 of $76.4 million, compared with operating cash flows of $19.1 million in the first nine months of 2010 (amounts are net of RRB payments, which are included in financing activities). The improved cash flows were due primarily to the impact of the DPU distribution rate case decision that was effective February 1, 2011, a net positive cash flow impact of $9.8 million largely attributable to accelerated depreciation tax benefits and a net positive cash flow impact associated with transmission overrecoveries in 2011, as compared to 2010.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

Commodity Price Risk Management: Our Regulated companies enter into energy contracts to serve our customers and the economic impacts of those contracts are passed on to our customers. Accordingly, the Regulated companies have no exposure to loss of future earnings or fair values due to these market risk-sensitive instruments. The remaining unregulated wholesale portfolio held by Select Energy includes contracts that are market risk-sensitive, including a wholesale energy sales contract through 2013 with an agency comprised of municipalities with approximately 0.1 million remaining MWh of supply contract volumes, net of related sales volumes. Select Energy also has a non-derivative energy contract that expires in mid-2012 to purchase output from a generation facility, which is also exposed to market price volatility. As Select Energy's contract volumes are winding down, and as the wholesale energy sales contract is substantially hedged against price risks, we have limited exposure to commodity price risks. We have not entered into any energy contracts for trading purposes.

Pension Plan Contributions Discount Rate Sensitivity Analysis: Fluctuations in the average discount rate used to calculate expected Pension Plan contributions can have a significant impact on the amount of Pension Plan contributions estimated to be required. As of December 31, 2010, the average discount rate used to calculate the expected Pension Plan contributions totaling $390 million for the period 2012 through 2015 was 6.29 percent. If this discount rate was decreased by 100 basis points, all other items remaining constant, then the expected aggregate contributions would increase to approximately $640 million for the period 2012 through 2015. In addition, the market performance of existing plan assets, the valuation of the plan's liabilities, and a variety of other factors would impact the Pension Plan contributions.

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. We have provided this analysis in Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," in our 2010 Form 10-K, which disclosures are incorporated herein by reference. There have been no additional market or commodity price risks identified and no material changes with regard to the sensitivity analysis previously disclosed in our 2010 Form 10-K.

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.

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.

If the respective unsecured debt ratings of NU parent or PSNH were reduced to below investment grade by either Moody s or S&P, certain of NU and PSNH s contracts would require additional collateral in the form of cash or LOCs to be provided to counterparties and independent system operators. If such an event occurred as of September 30, 2011, NU and PSNH would have been required to provide additional cash or LOCs in an aggregate amount of $23 million and $1.5 million, respectively. NU and PSNH would have been and remain able to provide that collateral.

For further information on cash collateral deposited and posted with counterparties as well as any cash collateral netted against the fair value of the related derivative contracts, see Note 4, "Derivative Instruments," to the unaudited condensed consolidated financial statements

We have provided additional disclosures regarding interest rate risk management and credit risk management in Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," in our 2010 Form 10-K, which are incorporated herein by reference. There have been no additional risks identified and no material changes with regard to the items previously disclosed in our 2010 Form 10-K.

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, 2011 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, 2011 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 2010 Form 10-K, and in Part II, Item 1, "Legal Proceedings," in our quarterly reports on Form 10-Q for the quarters ended March 31, and June 30, 2011, which disclosures are incorporated herein by reference. There have been no additional legal proceedings identified and no material changes with regard to the legal proceedings previously disclosed in those filings.

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 Item 2, "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 Item 1A, "Risk Factors," in our 2010 Form 10-K and in our quarterly report on Form 10-Q for the quarter ended June 30, 2011, 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 those filings.

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, 2011.

ITEM 6.

EXHIBITS

Each document described below is incorporated by reference by the registrant(s) listed to the files identified, unless designated with a (*), which exhibits are filed herewith.

Exhibit No.

Description

Listing of Exhibits (NU)

*12

Ratio of Earnings to Fixed Charges

*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 4, 2011

*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 4, 2011

*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 4, 2011

*101.INS

XBRL Instance Document

*101.SCH

XBRL Taxonomy Extension Schema

*101.CAL

XBRL Taxonomy Extension Calculation

*101.DEF

XBRL Taxonomy Extension Definition

*101.LAB

XBRL Taxonomy Extension Labels

*101.PRE

XBRL Taxonomy Extension Presentation

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 4, 2011

*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 4, 2011

*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 4, 2011

Listing of Exhibits (PSNH)

4.1

Nineteenth Supplemental Indenture between PSNH and U.S. Bank National Association, as Trustee, dated as of September 1, 2011 (incorporated by reference to Exhibit 4.1 to PSNH Current Report on Form 8-K filed September 16, 2011, Commission File No. 001-06392)

*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 4, 2011

*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 4, 2011

*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 4, 2011

Listing of Exhibits (WMECO)

4.1

Sixth Supplemental Indenture between WMECO and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated as of September 15, 2011 (incorporated by reference to Exhibit 4.1 to WMECO Current Report on Form 8-K filed September 19, 2011, Commission File No. 000-07624)

*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 4, 2011

*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 4, 2011

*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 4, 2011

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)

/s/

Date: November 4, 2011

By 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)

		/s/
Date: November 4, 2011	By	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)

/s/

Date: November 4, 2011

By 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)

		/s/
Date: November 4, 2011	By	David R. McHale David R. McHale Executive Vice President and Chief Financial Officer (for the Registrant and as Principal Financial Officer)