NORTHEAST UTILITIES
Form 10-Q
November 10, 2008

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, 2008

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		06-0303850

	THE CONNECTICUT LIGHT AND POWER COMPANY (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) 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**
Ö	

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

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

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

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 at October 31, 2008

Northeast Utilities Common stock, $5.00 par value	155,699,235 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 is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) of Form 10-Q.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found in this report.

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

Boulos	E.S. Boulos Company
CL&P	The Connecticut Light and Power Company
CRC	CL&P Receivables Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom generating plant
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the company	Northeast Utilities
NU Enterprises	At September 30, 2008, NU Enterprises, Inc. is the parent company of Select Energy, NGS, SECI and Boulos. For further information, see Note 9, "Segment Information," to the condensed consolidated financial statements.
NU parent and other companies	NU parent and other companies is comprised of NU parent, Northeast Utilities Service Company, HWP (since January 1, 2007) and other subsidiaries, including The Rocky River Realty Company and The Quinnehtuk Company (both real estate subsidiaries), Mode 1 Communications, Inc. (telecommunications) and the nonenergy-related subsidiaries of Yankee (Yankee Energy Services Company, Yankee Energy Financial Services Company, and NorConn Properties, Inc.)
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH and WMECO, the generation segment of PSNH and Yankee Gas, a natural gas local distribution company. For further information, see Note 9, "Segment Information," to the condensed consolidated financial statements.
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS:

DPU	Massachusetts Department of Public Utilities (formerly the Massachusetts Department of Telecommunications and Energy (DTE))
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER:

AFUDC	Allowance For Funds Used During Construction
CfD	Contract for Differences
Con Edison	Consolidated Edison, Inc.
CTA	Competitive Transition Assessment
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Charges
GSC	Generation Service Charge
ISO-NE	New England Independent System Operator or ISO New England, Inc.
KWH	Kilowatt-Hour
KV	Kilovolt
LOC	Letter of Credit
MW	Megawatts
NU 2007 Form 10-K	The Northeast Utilities and Subsidiaries combined 2007 Annual Report on Form 10-K as filed with the SEC
NYMPA	New York Municipal Power Agency
PBOP	Postretirement Benefits Other Than Pensions
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
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SFAS	Statement of Financial Accounting Standards
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer
UI	The United Illuminating Company
VAR	Voltage Ampere Reactive

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 82,818	$ 15,104
Investments in securitizable assets (Note 1E)	-	308,182
Receivables, less provision for uncollectible accounts of $44,423 in 2008 and $25,529 in 2007	623,834	401,283
Unbilled revenues	193,685	101,860
Taxes receivable	1,102	13,850
Fuel, materials and supplies	270,375	210,850
Marketable securities - current	80,623	70,816
Derivative assets - current	44,054	105,517
Prepayments and other	77,756	58,794
	1,374,247	1,286,256
Property, Plant and Equipment:		
Electric utility	8,378,452	7,594,606
Gas utility	1,011,311	977,290
Other	288,890	310,535
	9,678,653	8,882,431
Less: Accumulated depreciation: $2,591,645 for electric and gas utility and $158,751 for other in 2008; $2,483,570 for electric and gas utility and		

$178,193 for other in 2007		2,750,396		2,661,763
		6,928,257		6,220,668
Construction work in progress		1,012,770		1,009,277
		7,941,027		7,229,945
Deferred Debits and Other Assets:				
Regulatory assets		2,372,197		2,057,083
Goodwill		287,591		287,591
Prepaid pension		222,484		202,512
Marketable securities - long-term		35,020		53,281
Derivative assets - long-term		266,346		298,001
Other		164,821		167,153
		3,348,459		3,065,621
Total Assets	$	12,663,733	$	11,581,822

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 442,187	$ 79,000
Long-term debt - current portion	116,286	154,286
Accounts payable	463,966	598,546
Accrued interest	77,062	56,592
Derivative liabilities - current	64,175	71,601
Other	172,226	246,125
	1,335,902	1,206,150
Rate Reduction Bonds	743,345	917,436
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,175,988	1,067,490
Accumulated deferred investment tax credits	26,239	28,845
Deferred contractual obligations	197,304	222,908
Regulatory liabilities	645,235	851,780
Derivative liabilities - long-term	785,908	208,461
Accrued postretirement benefits	162,910	181,507
Other	427,289	383,611
	3,420,873	2,944,602
Capitalization:		
Long-Term Debt	4,031,432	3,483,599
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200

Common Shareholders' Equity:				
Common shares, $5 par value - authorized 225,000,000 shares; 176,179,925 shares issued and 155,661,854 shares outstanding in 2008 and 175,924,694 shares issued and 155,079,770 shares outstanding in 2007		880,899		879,623
Capital surplus, paid in		1,472,550		1,465,946
Deferred contribution plan - employee stock ownership plan		(18,726)		(26,352)
Retained earnings		1,039,984		946,792
Accumulated other comprehensive income		2,877		9,359
Treasury stock, 19,708,136 shares in 2008 and 19,705,545 shares in 2007		(361,603)		(361,533)
Common Shareholders' Equity		3,015,981		2,913,835
Total Capitalization		7,163,613		6,513,634
Commitments and Contingencies (Note 5)				
Total Liabilities and Capitalization	$	12,663,733	$	11,581,822

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,506,897	$ 1,450,977	$ 4,352,209	$ 4,546,267
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	801,050	881,234	2,286,066	2,756,522
Other	232,222	195,112	755,306	678,224
Maintenance	71,287	53,854	198,892	159,681
Depreciation	69,717	64,522	205,792	191,393
Amortization of regulatory assets, net	61,386	17,007	132,186	19,795
Amortization of rate reduction bonds	53,132	52,403	154,366	151,316
Taxes other than income taxes	69,026	63,485	200,133	193,435
Total operating expenses	1,357,820	1,327,617	3,932,741	4,150,366
Operating Income	149,077	123,360	419,468	395,901
Interest Expense:				
Interest on long-term debt	53,111	41,706	142,333	118,153
Interest on rate reduction bonds	12,207	15,111	38,910	47,300
Other interest	5,579	4,949	18,355	15,172
Interest expense, net	70,897	61,766	199,598	180,625
Other Income, Net	17,682	10,734	41,610	36,676

Income from Continuing Operations Before Income Tax Expense	95,862	72,328	261,480	251,952
Income Tax Expense	21,783	20,756	68,381	75,182
Income from Continuing Operations Before Preferred Dividends of Subsidiary	74,079	51,572	193,099	176,770
Preferred Dividends of Subsidiary	1,390	1,390	4,169	4,169
Income from Continuing Operations	72,689	50,182	188,930	172,601
Discontinued Operations:				
Income from Discontinued Operations	-	16	-	264
(Losses)/Gains from Sale/Disposition of Discontinued Operations	-	(90)	-	1,927
Income Tax (Benefit)/Expense	-	(16)	-	1,021
(Loss)/Income from Discontinued Operations	-	(58)	-	1,170
Net Income	$ 72,689	$ 50,124	$ 188,930	$ 173,771
Basic Earnings Per Common Share:				
Income from Continuing Operations	$ 0.47	$ 0.32	$ 1.22	$ 1.12
Income from Discontinued Operations	-	-	-	-
Basic Earnings Per Common Share	$ 0.47	$ 0.32	$ 1.22	$ 1.12
Fully Diluted Earnings Per Common Share:				
Income from Continuing Operations	$ 0.47	$ 0.32	$ 1.21	$ 1.11
Income from Discontinued Operations	-	-	-	0.01
Fully Diluted Earnings Per Common Share	$ 0.47	$ 0.32	$ 1.21	$ 1.12
Basic Common Shares Outstanding (weighted	155,607,201	154,930,930	155,456,606	154,672,270

average)				
Fully Diluted Common Shares Outstanding (weighted average)	156,097,641	155,420,239	155,904,871	155,210,704

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2008	2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 188,930	$ 173,771
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	21,341	19,983
Depreciation	205,792	191,393
Deferred income taxes	31,125	(41,144)
Pension expense, net of capitalized portion	5,956	13,776
(Deferral)/amortization of recoverable energy costs	(5,898)	1,494
Amortization of rate reduction bonds	154,366	151,316
Amortization of regulatory assets, net	132,186	19,795
Regulatory (refunds and underrecoveries)/overrecoveries	(97,888)	95,766
Derivative assets and liabilities	(32,369)	(31,641)
Deferred contractual obligations	(25,604)	(32,760)
Other non-cash adjustments	(19,532)	(2,561)
Other sources of cash	2,907	-
Other uses of cash	(28,315)	(33,101)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(10,356)	43,511
Fuel, materials and supplies	(59,554)	(57,281)
Investments in securitizable assets	(25,787)	18,137
Other current assets	(26,189)	(6,483)
Accounts payable	(58,594)	(91,473)
Counterparty deposits and margin special deposits	7,965	20,858

Taxes receivable/accrued		64,425		(350,529)
Other current liabilities		(2,801)		(34,676)
Net cash flows provided by operating activities		422,106		68,151
Investing Activities:				
Investments in property and plant		(951,831)		(750,231)
Proceeds from sales of investment securities		195,445		196,083
Purchases of investment securities		(197,453)		(199,964)
Rate reduction bond escrow and other deposits		465		8,436
Other investing activities		2,765		996
Net cash flows used in investing activities		(950,609)		(744,680)
Financing Activities:				
Issuance of common shares		5,002		8,988
Issuance of long-term debt		660,000		655,000
Retirements of rate reduction bonds		(174,091)		(161,926)
Increase in short-term debt		363,187		-
Retirements of long-term debt		(154,286)		(4,877)
Cash dividends on common shares		(95,824)		(89,745)
Other financing activities		(7,771)		(5,169)
Net cash flows provided by financing activities		596,217		402,271
Net increase/(decrease) in cash and cash equivalents		67,714		(274,258)
Cash and cash equivalents - beginning of period		15,104		481,911
Cash and cash equivalents - end of period	$	82,818	$	207,653

The accompanying notes are an integral part of these 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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (All Companies)

A.

Presentation

Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). The accompanying unaudited condensed consolidated financial statements should be read in conjunction with the entirety of this Quarterly Report on Form 10-Q, the first and second quarter 2008 Quarterly Reports on Form 10-Q and the Annual Reports of Northeast Utilities (NU or the company), The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO), which were filed with the SEC as part of the Northeast Utilities and subsidiaries combined 2007 Annual Report on Form 10-K (NU 2007 Form 10-K). The accompanying condensed consolidated financial statements contain, in the opinion of management, all adjustments (including normal, recurring adjustments) necessary to present fairly NU's and the above companies' financial position at September 30, 2008 and December 31, 2007, the results of operations for the three and nine months ended September 30, 2008 and 2007 and cash flows for the nine months ended September 30, 2008 and 2007. The results of operations and cash flows for the nine months ended September 30, 2008 and 2007 are not necessarily indicative of the results expected for a full year.

The condensed consolidated financial statements of NU and its subsidiaries, as applicable, include the accounts of all their respective subsidiaries. Intercompany transactions have been eliminated in consolidation.

The preparation of condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain reclassifications of prior period data included in the accompanying condensed consolidated financial statements have been made to conform with the current period's presentation.

NU's condensed consolidated statements of income for the three and nine months ended September 30, 2007 classify activity related to the following subsidiaries as discontinued operations:

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Northeast Generation Company (NGC),

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The Mt. Tom generating plant (Mt. Tom) previously owned by Holyoke Water Power Company (HWP), and

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Select Energy Contracting, Inc. (including Reeds Ferry Supply Co., Inc.) (SECI).

For the three and nine months ended September 30, 2007, the remaining portions of SECI that were included in continuing operations have been reclassified to discontinued operations in the condensed consolidated statements of income as a result of winding down SECI operations in 2007. The amounts of these reclassifications are as follows:

(Millions of Dollars)	**Three Months Ended September 30, 2007**	**Nine Months Ended September 30, 2007**
Operating revenues	$ 0.1	$ 1.2
Operating expenses	(0.1)	(1.0)
Other interest	-	0.1
Income from discontinued operations	-	0.3
	-	(0.3)

Income tax expense from discontinued operations		
Net (loss)/income from discontinued operations	-	-

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For further information regarding discontinued operations, see Note 7, "Discontinued Operations," to the condensed consolidated financial statements.

B.

Regulatory Accounting

The accounting policies of the regulated companies conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution segments of CL&P, PSNH and WMECO, along with PSNH's generation segment and Yankee Gas Service Company's (Yankee Gas) distribution segment, continue to be cost-of-service, rate regulated. Management believes that the application of SFAS No. 71 to those segments continues to be appropriate. Management also believes it is probable that NU's regulated companies will recover their investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets and the majority of deferred benefit costs, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in amortization expense on the accompanying condensed consolidated statements of income.

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

	At September 30, 2008				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Securitized assets	$ 733.9	$ 419.4	$ 239.1	$ 75.4	$ -
Income taxes, net	352.3	304.7	9.8	28.0	9.8
Deferred benefit costs	162.4	56.9	43.6	5.5	56.4
Unrecovered contractual obligations	173.6	136.2	-	37.4	-
Regulatory assets offsetting regulated company derivative liabilities	687.6	634.7	52.5	-	0.4

CL&P SBC undercollections		32.3		32.3		-		-		-
Other regulatory assets		230.1		100.2		62.3		15.9		51.7
Totals	$	2,372.2	$	1,684.4	$	407.3	$	162.2	$	118.3

	At December 31, 2007									
(Millions of Dollars)	**NU Consolidated**		**CL&P**		**PSNH**		**WMECO**		**Yankee Gas and Other**	
Securitized assets	$	907.0	$	548.2	$	273.2	$	85.6	$	-
Income taxes, net		335.5		279.4		10.3		38.2		7.6
Deferred benefit costs		201.4		72.2		50.4		8.2		70.6
Unrecovered contractual obligations		189.9		148.0		-		42.0		(0.1)
Regulatory assets offsetting regulated company derivative liabilities		122.3		119.8		2.5		-		-
CL&P CTA and SBC undercollections		90.6		90.6		-		-		-
Other regulatory assets		210.4		71.8		65.0		19.9		53.7
Totals	$	2,057.1	$	1,330.0	$	401.4	$	193.9	$	131.8

At December 31, 2007, CL&P's Competitive Transition Assessment (CTA) was recorded as a $54 million regulatory asset as CTA unrecovered costs were in excess of CTA collections. At September 30, 2008, CTA collections were in excess of CTA costs and a $26.7 million regulatory liability was recorded.

Included in regulatory assets offsetting regulated company derivative liabilities are $577.2 million and $86.7 million at September 30, 2008 and December 31, 2007, respectively, of derivative liabilities relating to CL&P   s capacity contracts, referred to as contracts for differences (CfDs). For further information, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Included in NU's other regulatory assets are the regulatory assets associated with the implementation of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $44.3 million at September 30, 2008 and $40.6 million at December 31, 2007. Management believes that recovery of these regulatory assets is probable.

Additionally, the regulated companies had $4.2 million and $11.9 million of regulatory costs at September 30, 2008 and December 31, 2007, respectively, that were included in deferred debits and other assets - other on the accompanying condensed consolidated balance

sheets. These amounts represent regulatory costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are recoverable in future cost-of-service regulated rates.

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

	At September 30, 2008				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Cost of removal	$ 231.7	$ 94.1	$ 66.3	$ 20.4	$ 50.9
Regulatory liabilities offsetting regulated company derivative assets	212.1	200.9	10.5	-	0.7
CL&P CTA, GSC and FMCC overcollections	64.7	64.7	-	-	-
CL&P AFUDC transmission incentive	42.2	42.2	-	-	-
Other regulatory liabilities	94.5	39.0	18.8	13.1	23.6
Totals	$ 645.2	$ 440.9	$ 95.6	$ 33.5	$ 75.2

	At December 31, 2007				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas**
Cost of removal	$ 262.6	$ 116.6	$ 72.8	$ 21.5	$ 51.7
Regulatory liabilities offsetting regulated company derivative assets	330.4	313.0	17.2	-	0.2
CL&P GSC and FMCC overcollections	119.2	119.2	-	-	-
CL&P AFUDC transmission incentive	21.4	21.4	-	-	-
Other regulatory liabilities	118.2	31.3	37.6	17.9	31.4
Totals	$ 851.8	$ 601.5	$ 127.6	$ 39.4	$ 83.3

Included in regulatory liabilities offsetting regulated company derivative assets are $0.4 million at December 31, 2007 of derivative assets relating to CL&P s CfDs. For further information, see Note 2, "Derivative Instruments," to the condensed consolidated financial statements. For information regarding CL&P allowance for funds used during construction (AFUDC) transmission incentive, see Note 1D, "Summary of Significant Accounting Policies - Allowance for Funds Used During Construction," to the condensed consolidated financial statements.

C.

Fair Value Measurements

On January 1, 2008, the company adopted SFAS No. 157, "Fair Value Measurements," which establishes a framework for defining and measuring fair value and requires expanded disclosures about fair value measurements. SFAS No. 157:

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Defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price).

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Establishes a three-level fair value hierarchy based upon the observability of inputs to the valuations of assets and liabilities.

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Requires consideration of the company's own creditworthiness and risk of nonperformance when valuing its liabilities.

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Requires prospective implementation with adjustments to fair value reflected in earnings, similar to a change in estimate, with exceptions including recognition of previously deferred initial gains or losses described below.

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Requires recognition in retained earnings of previously deferred initial gains or losses on derivative contracts whose estimated fair values are based on significant unobservable inputs. Recognition of the initial gains or losses was previously prohibited under Emerging Issues Task Force Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." CL&P s initial gains and losses on its CfDs that would have been recorded in retained earnings upon adoption were recorded as regulatory assets and liabilities because their costs or benefits are expected to be fully recovered from or refunded to customers.

The company applied SFAS No. 157 to the regulated and unregulated companies' derivative contracts that are recorded at fair value and to the marketable securities held in NU's Rabbi Trust and WMECO's prior spent nuclear fuel trust. SFAS No. 157 also applies to investment valuations for NU s pension and other postretirement benefit plans beginning as of December 31, 2008, and beginning in 2009, to nonrecurring fair value measurements of non-financial assets and liabilities such as goodwill and asset retirement obligations.

As a result of adopting SFAS No. 157, the company recorded a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to derivative liabilities for its remaining unregulated wholesale marketing contracts. In the first nine months of 2008, the company recorded a $1.5 million pre-tax benefit to partially reverse the exit price impact recorded under SFAS No. 157 as the company served out rather than exited the contracts.

The company also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers and an offsetting regulatory asset or liability was recorded to reflect these changes. As of January 1, 2008, implementing SFAS No. 157 resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets, of approximately $590 million, and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million.

Fair Value Hierarchy: As required by SFAS No. 157, in measuring fair value the company uses observable market data when available and minimizes the use of unobservable inputs. Unobservable inputs are needed to value certain derivative contracts due to complexities in contractual terms and the long duration of a contract. SFAS No. 157 requires inputs used in fair value measurements to be categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement.

The three levels of the fair value hierarchy are described below:

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

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

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

Determination of Fair Value: The following is a description of the valuation techniques utilized in our fair value measurements:

Derivative contracts: Many of the company's derivative positions that are recorded at fair value are classified as Level 3 within the fair value hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit. The derivative contracts classified as Level 3 include NU Enterprises, Inc.'s (NU Enterprises) remaining wholesale marketing contract and its related supply contracts, CL&P's CfDs, CL&P's contracts with certain independent power producers (IPPs) and regulated company options and financial transmission rights (FTRs).

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

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

Marketable securities: The company holds in trust marketable securities, which include equity securities, mutual funds and cash equivalents, and fixed maturity securities.

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

Fixed maturity securities classified as Level 2 within the fair value hierarchy include U.S. Treasury securities, corporate bonds, collateralized mortgage obligations, U.S. pass-through bonds, asset-backed securities, commercial mortgage-backed securities, and commercial paper. The fair value of these instruments is estimated using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures.

For further information see Note 3, "Fair Value Measurements," to the accompanying condensed consolidated financial statements.

D.

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 on the accompanying condensed consolidated statements of income:

	For the Three Months Ended		For the Nine Months Ended	
(Millions of Dollars, except percentages)	**September 30, 2008**	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Borrowed funds	$ 4.3	$ 4.3	$ 13.5	$ 12.9
Equity funds	8.5	4.8	23.5	11.1
Totals	$ 12.8	$ 9.1	$ 37.0	$ 24.0
Average AFUDC rates	8.4%	7.6%	8.3%	7.3%

The regulated companies' average AFUDC rate is based on a Federal Energy Regulatory Commission (FERC) prescribed formula that produces an average rate using the cost of a company's short-term financings as well as a company's capitalization (preferred stock, long-term debt and common equity). The average rate is applied to average eligible construction work in progress (CWIP) amounts to calculate AFUDC. Although AFUDC is recorded on 100 percent of CL&P's CWIP for its major transmission projects in southwest Connecticut, 50 percent of this AFUDC is being reserved as a regulatory liability to reflect current rate base recovery for 50 percent of the CWIP as a result of FERC approved transmission incentives.

E.

Sale of Customer Receivables

Prior to June 30, 2008, under the Receivables Purchase and Sale Agreement, CL&P Receivables Corporation (CRC), a consolidated, wholly-owned subsidiary of CL&P, purchased an undivided interest in CL&P's accounts receivable and unbilled revenues and could sell up to $100 million thereof to a financial institution. At December 31, 2007, there were $20 million in such sales. On June 30, 2008, CL&P chose to terminate the Receivables Purchase and Sale Agreement and there are no receivables sold under that facility.

At December 31, 2007, amounts totaling $308.2 million sold to CRC by CL&P but not sold to the financial institution were included in investments in securitizable assets on the accompanying condensed consolidated balance sheet. These amounts would have been excluded from CL&P's assets in the event of bankruptcy by CL&P. Since CL&P chose to terminate the Receivables Purchase and Sale Agreement on June 30, 2008, all such amounts are now included in accounts receivables and unbilled revenues on the accompanying condensed consolidated balance sheet as of September 30, 2008.

F.

Other Income, Net

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

NU	**For the Three Months Ended**		**For the Nine Months Ended**	
(Millions of Dollars)	**September 30, 2008**	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Other Income:				
Investment income	$ 2.3	$ 4.2	$ 6.1	$ 18.6
2008 federal tax settlement - interest	10.1	-	10.1	-
AFUDC - equity funds	8.5	4.8	23.5	11.1
Energy Independence Act incentives	0.5	0.1	9.4	5.0
Conservation and load management incentives	0.1	1.4	(0.3)	1.8
Other	0.2	0.2	0.8	0.8
Total Other Income	21.7	10.7	49.6	37.3
Other Loss:				
Investment loss	(4.0)	-	(7.8)	-
Investment write-down	-	-	-	(0.5)
Other	-	-	(0.2)	(0.1)
Total Other Loss	(4.0)	-	(8.0)	(0.6)
Total Other Income, Net	$ 17.7	$ 10.7	$ 41.6	$ 36.7

CL&P	**For the Three Months Ended**		**For the Nine Months Ended**	
(Millions of Dollars)	**September 30, 2008**	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Other Income:				
Investment income	$ 1.7	$ 1.3	$ 5.0	$ 4.3
2008 federal tax settlement - interest	6.4	-	6.4	-
AFUDC - equity funds	7.0	4.7	19.4	9.0
	0.5	0.1	9.4	5.0

Energy Independence Act incentives								
Conservation and load management incentives		-		1.3		(0.6)		1.4
Other		0.2		0.1		0.5		0.6
Total Other Income		15.8		7.5		40.1		20.3
Investment loss		(2.7)		-		(5.3)		-
Total Other Income, Net	$	13.1	$	7.5	$	34.8	$	20.3

PSNH	**For the Three Months Ended**				**For the Nine Months Ended**			
(Millions of Dollars)	**September 30, 2008**		**September 30, 2007**		**September 30, 2008**		**September 30, 2007**	
Other Income:								
Investment income	$	0.5	$	0.2	$	1.4	$	0.6
2008 federal tax settlement - interest		1.9		-		1.9		-
AFUDC - equity funds		0.9		-		3.2		0.9
Other		-		-		0.1		0.1
Total Other Income		3.3		0.2		6.6		1.6
Investment loss		(0.6)		-		(1.3)		-
Total Other Income, Net	$	2.7	$	0.2	$	5.3	$	1.6

WMECO	**For the Three Months Ended**				**For the Nine Months Ended**			
(Millions of Dollars)	**September 30, 2008**		**September 30, 2007**		**September 30, 2008**		**September 30, 2007**	
Other Income:								
Investment income	$	0.2	$	0.2	$	0.9	$	0.8
2008 federal tax settlement - interest		1.1		-		1.1		-
AFUDC - equity funds		0.5		-		0.9		-
Conservation and load management incentives		0.1		0.1		0.3		0.4
Total Other Income		1.9		0.3		3.2		1.2
Investment loss		(0.6)		-		(1.1)		-
Total Other Income, Net	$	1.3	$	0.3	$	2.1	$	1.2

Investment income for NU includes equity in earnings of regional nuclear generating and transmission companies of $0.4 million for both the three months ended September 30, 2008 and 2007, and $1.4 million and $1.5 million for the nine months ended September 30, 2008 and 2007, respectively. Equity in earnings relates to the company's investment in Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company, Yankee Atomic Electric Company and two regional transmission companies.

For further information regarding interest from the 2008 federal tax settlement, see Note 1G, "Summary of Significant Accounting Policies - Income Taxes," to the condensed consolidated financial statements.

G.

Income Taxes

Tax Positions: In September 2008, NU and the Internal Revenue Service (IRS) reached a settlement agreement related to the timing for deducting certain costs. This agreement will close the federal tax years 2002 through 2004. The issues regarding the timing for deducting these costs are also subject to review during the 2005 through 2007 IRS federal audit cycle and therefore are not considered effectively settled for years after 2004. While this settlement had a $10.1 million pre-tax impact on interest income, it did not have a significant impact on income tax expense. The receivable related to this settlement of $18.1 million was included in current assets - prepayments and other on the accompanying condensed consolidated balance sheet at September 30, 2008. NU is actively working to reach resolution of these matters regarding the timing for certain deductions in the remaining open federal tax years. While discussions are currently ongoing with federal and state taxing authorities, for which a change in the unrecognized tax benefits over the next twelve months is reasonably possible, a range in the outcome could not be determined as of this date.

H.

Other Taxes

Certain excise taxes levied by state or local governments are collected by NU from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. For the three and nine months ended September 30, 2008, gross receipts taxes, franchise taxes and other excise taxes of $33.9 million and $92.4 million, respectively, were included in operating revenues and taxes other than income taxes on the accompanying condensed consolidated statements of income. For the three and nine months ended September 30, 2007, these amounts totaled $27 million and $84.9 million, respectively. Certain sales taxes are also collected by the regulated companies from their customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying condensed consolidated statements of income.

2.

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

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchase or normal sale are recorded at fair value with changes in fair value included in earnings. For those contracts that meet the definition of a derivative and meet the cash flow hedge requirements, including those related to initial and ongoing documentation, the contract is recorded at fair value and the changes in the fair value of the effective portion of those contracts are recognized in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. Cash flow hedges impact net income when the hedged items affect earnings, when hedge ineffectiveness is measured and recorded, or when the forecasted transaction being hedged is improbable of occurring. Derivative contracts designated as fair value hedges and the items they are hedging are both recorded at fair value with changes in fair value of both items recognized in earnings. Derivative contracts that meet the requirements of a normal purchase or sale, and are so designated, are recognized in revenues or expenses, as applicable, when the quantity of the contract is delivered.

The fair value of the company's derivative contracts may not represent amounts that will be realized. For further information on the fair value of derivative contracts, see Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the condensed consolidated financial statements. On the accompanying condensed consolidated balance sheets at September 30, 2008 and December 31, 2007, these amounts are recorded as current or long-term derivative assets or liabilities and are summarized as follows:

	At September 30, 2008				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises - Wholesale	$ 4.1	$ 3.1	$ (18.5)	$ (57.3)	$ (68.6)
Regulated Companies - Gas:					
Supply	-	0.7	(0.4)	-	0.3
Regulated Companies - Electric:					
Supply/Stranded Costs	40.0	258.1	(45.3)	(728.6)	(475.8)
NU Parent:					
Interest Rate Hedging	-	4.4	-	-	4.4
Totals	$ 44.1	$ 266.3	$ (64.2)	$ (785.9)	$ (539.7)

	At December 31, 2007				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises - Wholesale	$ 36.2	$ 7.2	$ (64.9)	$ (72.5)	$ (94.0)
Regulated Companies - Gas:					
Supply	0.2	-	-	-	0.2
Interest Rate Hedging	0.9	-	-	-	0.9
Regulated Companies - Electric:					
Supply/Stranded Costs	59.8	290.8	(6.7)	(136.0)	207.9
Interest Rate Hedging	3.3	-	-	-	3.3
NU Parent:					
Interest Rate Hedging	5.1	-	-	-	5.1
Totals	$ 105.5	$ 298.0	$ (71.6)	$ (208.5)	$ 123.4

For the regulated companies, except for interest rate swap agreements, offsetting regulatory assets or liabilities are recorded for the changes in fair value of their contracts, as these contracts were part of the stranded costs or are current regulated operating costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates.

The business activities of NU Enterprises that result in the recognition of derivative assets also create exposures to credit risk of energy marketing and trading counterparties. At September 30, 2008, Select Energy, Inc. (Select Energy) had $7.2 million of derivative assets from wholesale activities that are exposed to counterparty credit risk, a significant portion of which is contracted with investment grade entities.

NU Enterprises - Wholesale: Certain electric derivative contracts are part of NU Enterprises' remaining wholesale marketing business. These contracts include short-term and long-term electric supply contracts and a contract to sell electricity to the New York Municipal Power Agency (NYMPA) (an agency that is comprised of municipalities) that expires in 2013. The fair value of the contracts was determined using prices from external sources through 2011 for on-peak and off-peak periods and through 2012 for on-peak periods, except for one contract, under which a portion of the fair value is also determined from a model based on natural gas prices and a heat-rate conversion factor to electricity for off-peak periods in 2012 and for all periods in 2013. The 2007 balances also included a full requirements contract and the related short-term supply contracts to sell electricity to a utility. These full requirements contracts expired on May 31, 2008.

Regulated Companies - Gas - Supply: Yankee Gas's supply derivatives consist of peaking supply arrangements to serve winter load obligations and firm retail sales contracts with options to curtail delivery. These contracts are subject to fair value accounting as these contracts are derivatives that cannot be designated as normal purchases and sales because of the optionality in the contract terms. An offsetting regulatory liability/asset was recorded for these amounts as management believes that these costs will be refunded or recovered in rates.

Regulated Companies - Gas - Interest Rate Hedging: Yankee Gas had a forward interest rate swap agreement to hedge the interest cash outflows associated with its $100 million debt issuance in October 2008. The interest rate swap was based on a 10-year LIBOR swap rate and matched the index used for the debt issuance. As a cash flow hedge, the fair value of the hedge was recorded as a derivative asset on the accompanying condensed consolidated balance sheets as of December 31, 2007, with an offsetting amount, net of tax, included in accumulated other comprehensive income. The swap was terminated in September 2008.

Regulated Companies - Electric - Supply/Stranded Costs: CL&P has contracts with two IPPs to purchase power that contain pricing provisions that are not clearly and closely related to the price of power and therefore do not qualify for the normal purchases and sales exception. The fair values of these derivatives at September 30, 2008 included a derivative asset with a fair value of $199.3 million and a derivative liability with a fair value of $57.5 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. At December 31, 2007, the fair values of these derivatives included a derivative asset with a fair value of $311.2 million and a derivative liability with a fair value of $31.8 million.

CL&P has entered into FTR contracts and bilateral basis swaps to limit the congestion costs associated with its standard offer contracts. An offsetting regulatory asset or liability has been recorded as management believes that these costs will be recovered or refunded in rates. At September 30, 2008, the fair value of these contracts was recorded as a derivative asset of $1.6 million on the accompanying condensed consolidated balance sheets. At December 31, 2007, the fair value of these contracts was recorded as a derivative asset of $1.4 million and a derivative liability of $1.3 million on the accompanying condensed consolidated balance sheets.

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August 2007, the Connecticut Department of Public Utility Control (DPUC) approved two CL&P contracts associated with the capacity of two generating projects to be built or modified. The DPUC also approved two capacity-related contracts entered into by The United Illuminating Company (UI), one with a generating project to be built and one with a new demand response project. The total capacity of these four projects is expected to be approximately 787 megawatts (MW). The contracts, referred to as CfDs, obligate the utilities' customers to pay the difference between a set capacity price and the forward capacity market price that the projects receive in the New England Independent System Operator (ISO-NE) capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent to CL&P and 20 percent to UI. The ultimate cost to CL&P under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. At September 30, 2008, the fair value of the CL&P CfDs was recorded as a derivative liability of $663.9 million. The fair values of UI's share of the CL&P's contracts and CL&P's share of UI's contracts were recorded as a derivative asset of $86.7 million. An offsetting regulatory asset of $577.2 million was recorded, as management believes these amounts will be recovered from or refunded to customers in cost-of-service, regulated rates. The value of CL&P's CfDs at September 30, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation, that were recorded upon adoption of SFAS No. 157 on January 1, 2008. At December 31, 2007, changes in CfD fair values since inception were recorded as a derivative liability of $107.1 million, and UI's share and one CL&P CfD were recorded as derivative assets of $20.8 million. Offsetting regulatory assets of $86.7 million and regulatory liabilities of $0.4 million were also recorded at December 31, 2007. A 2007 NRG Energy, Inc. (NRG) appeal of the DPUC's decision selecting the CfDs was taken into consideration in valuing the CfDs as of December 31, 2007, reducing the net negative derivative values by approximately $215 million. In February 2008, the appeal was denied, which increased derivative liabilities in 2008.

PSNH has electricity procurement contracts that are derivatives. The fair values of these contracts are calculated based on market prices and were recorded as derivative liabilities totaling $52.5 million at September 30, 2008. At December 31, 2007, the fair value was recorded as a derivative asset of $1.5 million and a derivative liability of $2.5 million. An offsetting regulatory asset/liability was recorded as management believes that these costs will be refunded or recovered in rates as the energy is delivered.

PSNH has a contract to assign its transmission rights in a direct current transmission line in exchange for two energy call options which expire in 2010. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value based on option value modeling. At September 30, 2008 and December 31, 2007, the options were recorded as a derivative asset of $10.5 million and $15.7 million, respectively. An offsetting regulatory liability was recorded, as management believes the benefit of this arrangement will be refunded to customers in rates.

Regulated Companies - Electric - Interest Rate Hedging: At December 31, 2007, CL&P had two forward interest rate swap agreements to hedge the interest cash outflows associated with its debt issuance of $300 million in May 2008. PSNH had a forward interest rate swap agreement to hedge the interest cash outflows associated with its debt issuance of $110 million in May 2008. Prior to termination in May 2008, the interest rate swaps were based on a

10-year LIBOR swap rate and matched the index used for the debt issuances. As cash flow hedges, the fair values of these hedges were recorded as derivative assets at December 31, 2007 on the accompanying condensed consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

NU Parent - Interest Rate Hedging: In March 2003, to manage the interest rate characteristics of the company's long-term debt, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate senior notes that mature on April 1, 2012. Under fair value hedge accounting, the changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in interest expense, which generally offset each other in the condensed consolidated statements of income. The cumulative change in the fair value of the swap and the long-term debt was recorded as a derivative asset and an increase to long-term debt of $4.4 million and $4.2 million at September 30, 2008 and December 31, 2007, respectively.

NU parent had a forward interest rate swap agreement to hedge the interest cash outflows associated with its planned debt issuance in June 2008. Prior to termination in June 2008, the interest rate swap was based on a 5-year LIBOR swap rate and a notional amount of $200 million, and matched the index used for the debt issuance. As a cash flow hedge at December 31, 2007, the fair value of the hedge was recorded as a $0.9 million derivative asset on the accompanying condensed consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

3.

FAIR VALUE MEASUREMENTS (All Companies)

Items Measured at Fair Value on a Recurring Basis: The company's assets and liabilities recorded at fair value on a recurring basis have been categorized based upon the fair value hierarchy in accordance with SFAS No. 157. See Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," for further information regarding the hierarchy and fair value measurements.

The following table presents the amounts of assets and liabilities carried at fair value at September 30, 2008 by the level in which they are classified within the SFAS No. 157 valuation hierarchy:

(Millions of Dollars)	Total NU	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	NU Parent
Derivative Assets:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	4.4	-	-	-	-	-	4.4
Level 3	306.0	287.6	10.5	-	7.2	0.7	-
Total	$ 310.4	$ 287.6	$ 10.5	$ -	$ 7.2	$ 0.7	$ 4.4
Derivative Liabilities:							
Level 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Level 2	(52.5)	-	(52.5)	-	-	-	-
Level 3	(797.6)	(721.4)	-	-	(75.8)	(0.4)	-
Total	$ (850.1)	$ (721.4)	$ (52.5)	$ -	$ (75.8)	$ (0.4)	$ -
Marketable Securities:							
Level 1	$ 38.7	$ -	$ -	$ 5.1	$ -	$ -	$ 33.6
Level 2	76.9	-	-	50.6	-	-	26.3
Level 3	-	-	-	-	-	-	-
Total	$ 115.6	$ -	$ -	$ 55.7	$ -	$ -	$ 59.9

Not included in the table above are $62.6 million of cash equivalents included in cash and cash equivalents on the accompanying condensed consolidated balance sheet, which are classified as Level 1 in the fair value hierarchy. These assets were held in a money market account at September 30, 2008 primarily to repurchase the CL&P PCRBs on October 1, 2008. See Note 10, "Subsequent Events," to the condensed consolidated financial statements.

The following tables present changes for the three and nine months ended September 30, 2008 in the Level 3 category of assets and liabilities measured at fair value on a recurring basis. This category includes derivative assets and liabilities, which are presented net. The derivative amounts at January 1, 2008 reflect the fair values after initial adoption of SFAS No. 157. 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, 2008.

	For the Three Months Ended September 30, 2008				
(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
Derivatives, Net:					
Fair value at June 30, 2008	$ (277.0)	$ (244.9)	$ 40.9	$ (74.6)	$ 1.6
Net realized/unrealized gains included in:					
Earnings [(1)]	5.3	-	-	5.3	-
Regulatory assets/liabilities	(195.8)	(164.1)	(30.4)	-	(1.3)
Purchases, issuances and settlements	(24.1)	(24.8)	-	0.7	-
Fair value at September 30, 2008	$ (491.6)	$ (433.8)	$ 10.5	$ (68.6)	$ 0.3
Quarterly change in unrealized gains included in earnings relating to items held at September 30, 2008	$ 6.0	$ -	$ -	$ 6.0	$ -

	For the Nine Months Ended September 30, 2008				
(Millions of Dollars)	Total NU	CL&P	PSNH	NU Enterprises	Yankee Gas
Derivatives, Net:					
Fair value at January 1, 2008 [(2)]	$ (511.1)	$ (426.9)	$ 15.7	$ (100.1)	$ 0.2
Net realized/unrealized gains included in:					
Earnings [(1)]	10.2	-	-	10.2	-
Regulatory assets/liabilities	49.7	54.8	(5.2)	-	0.1
Purchases, issuances and settlements	(40.4)	(61.7)	-	21.3	-
Fair value at September 30, 2008	$ (491.6)	$ (433.8)	$ 10.5	$ (68.6)	$ 0.3
Period change in unrealized gains included in earnings relating to items held at September 30, 2008	$ 4.5	$ -	$ -	$ 4.5	$ -

(1)

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

(2)

Amounts as of January 1, 2008 reflect fair values after initial adoption of SFAS No. 157. As a result of implementing SFAS No. 157, the company recorded an increase to derivative liabilities and a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to NU Enterprises' remaining derivative contracts. The company also recorded changes in fair value of CL&P's CfD and IPP contracts, resulting in increases to CL&P's derivative liabilities of approximately $590 million, with an offset to regulatory assets and a decrease to CL&P's derivative assets of approximately $30 million with an offset to regulatory liabilities.

4.

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

NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees and also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees (post-retirement benefits other than pension (PBOP) Plan). In addition, NU maintains a Supplemental Executive Retirement Plan (SERP) which provides benefits to eligible participants, who are officers of NU, and would have been provided to them under the Pension Plan if certain Internal Revenue Code and other limitations were not imposed.

The components of net periodic expense/(income) for the Pension Plan, PBOP Plan and SERP for the three and nine months ended September 30, 2008 and 2007 are as follows:

NU	**For the Three Months Ended September 30,**					
	Pension Benefits		**Postretirement Benefits**		**SERP Benefits**	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
Service cost	$ 11.1	$ 11.4	$ 1.8	$ 1.6	$ 0.2	$ 0.2
Interest cost	35.9	33.7	7.0	6.2	0.5	0.5
Expected return on plan assets	(50.0)	(48.4)	(5.3)	(4.6)	-	-
Amortization of unrecognized net transition obligation	-	-	2.9	3.2	-	-
Amortization of prior service cost	2.5	2.5	(0.1)	(0.1)	-	-
Amortization of actuarial loss	1.1	4.1	2.7	2.9	0.1	0.2
Net periodic expense - before termination benefits	0.6	3.3	9.0	9.2	0.8	0.9
Termination benefits	-	(0.3)	-	-	-	-
Total - net periodic expense	$ 0.6	$ 3.0	$ 9.0	$ 9.2	$ 0.8	$ 0.9

NU	For the Nine Months Ended September 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 32.8	$ 35.7	$ 5.3	$ 5.8	$ 0.5	$ 0.6
Interest cost	108.1	102.8	21.2	19.5	1.5	1.5
Expected return on plan assets	(150.2)	(146.8)	(15.8)	(13.7)	-	-
Amortization of unrecognized net transition obligation	0.2	0.1	8.7	9.0	-	-
Amortization of prior service cost	7.4	6.4	(0.2)	(0.2)	0.1	0.1
Amortization of actuarial loss	3.6	15.9	7.9	8.7	0.2	0.5
Net periodic expense - before termination benefits	1.9	14.1	27.1	29.1	2.3	2.7
Termination benefits	-	(0.3)	-	-	-	-
Total - net periodic expense	$ 1.9	$ 13.8	$ 27.1	$ 29.1	$ 2.3	$ 2.7

A portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were approximately $1.4 million and $4.1 million for the three and nine months ended September 30, 2008, respectively, and $0.4 million and a de minimis amount for the three and nine months ended September 30, 2007, respectively. These amounts offset capital costs, as pension income was recorded for certain of NU s subsidiaries.

CL&P	For the Three Months Ended September 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 3.9	$ 3.9	$ 0.6	$ 0.5	$ -	$ -
Interest cost	12.8	12.1	2.8	2.4	0.1	-
Expected return on plan assets	(23.4)	(22.5)	(2.1)	(1.8)	-	-
Amortization of unrecognized net transition obligation	-	-	1.5	1.2	-	-
	1.1	1.0	-	-	-	-

Amortization of prior service cost												
Amortization of actuarial loss		0.3		1.2		1.1		1.5		-		0.1
Net periodic (income)/expense	$	(5.3)	$	(4.3)	$	3.9	$	3.8	$	0.1	$	0.1

CL&P	**For the Nine Months Ended September 30,**											
	Pension Benefits				**Postretirement Benefits**				**SERP Benefits**			
(Millions of Dollars)	**2008**		**2007**		**2008**		**2007**		**2008**		**2007**	
Service cost	$	11.5	$	12.2	$	1.6	$	1.9	$	-	$	-
Interest cost		38.6		36.8		8.5		7.6		0.1		0.1
Expected return on plan assets		(70.1)		(68.2)		(6.3)		(5.4)		-		-
Amortization of unrecognized net transition obligation		-		-		4.6		4.3		-		-
Amortization of prior service cost		3.2		2.8		-		-		-		-
Amortization of actuarial loss		0.8		5.1		3.4		3.8		0.1		0.1
Net periodic (income)/expense	$	(16.0)	$	(11.3)	$	11.8	$	12.2	$	0.2	$	0.2

Not included in the pension income amounts above are related intercompany allocations totaling $2 million and $6 million for the three and nine months ended September 30, 2008, respectively, and $2.6 million and $8.6 million for the three and nine months ended September 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $1.7 million and $5.1 million for the three and nine months ended September 30, 2008, respectively, and $1.9 million and $5.5 million for the three and nine months ended September 30, 2007, respectively. Excluded from SERP expenses are related intercompany allocations of $0.4 million and $1.2 million for the three and nine months ended September 30, 2008, respectively, and $0.5 million and $1.4 million for the three and nine months ended September 30, 2007, respectively.

For CL&P, a portion of the pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $2.1 million and $6.5 million for the three and nine months ended September 30, 2008, respectively, and $1.3 million and $3.2 million for the three and nine months ended September 30, 2007, respectively. These amounts offset capital costs, as pension income was recorded for those periods.

PSNH	For the Three Months Ended September 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 2.3	$ 2.3	$ 0.4	$ 0.4	$ -	$ -
Interest cost	5.7	5.3	1.3	1.2	0.1	0.1
Expected return on plan assets	(4.5)	(4.4)	(1.0)	(0.8)	-	-
Amortization of unrecognized net transition obligation	0.1	0.1	0.6	0.6	-	-
Amortization of prior service cost	0.5	0.5	-	-	-	-
Amortization of actuarial loss	0.4	0.9	0.5	0.6	-	-
Net periodic expense	$ 4.5	$ 4.7	$ 1.8	$ 2.0	$ 0.1	$ 0.1

PSNH	For the Nine Months Ended September 30,					
	Pension Benefits		Postretirement Benefits		SERP Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Service cost	$ 6.9	$ 7.3	$ 1.2	$ 1.3	$ -	$ -
Interest cost	17.4	16.3	3.9	3.6	0.1	0.1
Expected return on plan assets	(13.4)	(13.4)	(3.0)	(2.5)	-	-
Amortization of unrecognized net transition obligation	0.2	0.2	1.9	1.8	-	-
Amortization of prior service cost	1.4	1.3	-	-	-	-
Amortization of actuarial loss	1.1	3.1	1.3	1.7	0.1	0.2
Net periodic expense	$ 13.6	$ 14.8	$ 5.3	$ 5.9	$ 0.2	$ 0.3

Not included in the pension expense amounts above are related intercompany allocations totaling $0.4 million and $1.2 million for the three and nine months ended September 30, 2008, respectively, and $0.4 million and $1.4 million for the three and nine months ended September 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $0.4 million and $1.1 million for the three and nine months ended September 30, 2008, respectively, and $0.3 million and $1 million for the three and nine months ended September 30, 2007, respectively. Excluded from SERP expenses are related intercompany allocations of $0.1 million and $0.3 million for both the three and nine months ended September 30, 2008 and 2007, respectively.

For PSNH, a portion of these pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $1.2 million and $3.5 million for the three and nine months ended September 30, 2008, respectively, and $1.1 million and $3.6 million for the three and nine months ended September 30, 2007, respectively.

WMECO	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**
(Millions of Dollars)								
Service cost	$ 0.8	$ 0.8	$ 0.1	$ 0.1	$ 2.4	$ 2.5	$ 0.4	$ 0.4
Interest cost	2.6	2.4	0.6	0.5	7.8	7.4	1.8	1.7
Expected return on plan assets	(5.2)	(4.9)	(0.5)	(0.4)	(15.6)	(15.1)	(1.5)	(1.3)
Amortization of unrecognized net transition obligation	-	-	0.4	0.2	-	-	1.0	0.8
Amortization of prior service cost	0.2	0.2	-	-	0.7	0.6	-	-
Amortization of actuarial loss	0.1	0.2	0.1	0.3	0.1	0.9	0.4	0.7
Net periodic (income)/expense	$ (1.5)	$ (1.3)	$ 0.7	$ 0.7	$ (4.6)	$ (3.7)	$ 2.1	$ 2.3

A de minimis amount of SERP expense was recorded for WMECO for each of the three and nine months ended September 30, 2008 and 2007. Related intercompany allocations of SERP benefits totaled $0.1 million and $0.2 million for both the three and nine months ended September 30, 2008 and 2007, respectively.

Not included in the pension income amounts above are related intercompany allocations totaling $0.3 million and $1 million for the three and nine months ended September 30, 2008, respectively, and $0.4 million and $1.4 million for the three and nine months ended September 30, 2007, respectively. Excluded from postretirement benefits are related intercompany allocations of $0.3 million and $0.8 million for the three and nine months ended September 30, 2008, respectively, and $0.3 million and $0.9 million for the three and nine months ended September 30, 2007, respectively.

For WMECO, a portion of these pension amounts, including intercompany allocations, is capitalized related to current employees that are working on capital projects. Amounts capitalized were $0.6 million and $1.7 million for the three and nine months ended

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September 30, 2008, respectively, and $0.4 million and $1.2 million for the three and nine months ended September 30, 2007, respectively. These amounts offset capital costs, as pension income was recorded for those periods.

5.

COMMITMENTS AND CONTINGENCIES

A.

Regulatory Developments and Rate Matters (CL&P, PSNH, WMECO)

Connecticut:

CTA and SBC Reconciliation: The CTA allows CL&P to recover stranded costs, such as securitization costs associated with its rate reduction bonds, amortization of regulatory assets, and IPP over-market costs, while the System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes, and displaced worker protection costs.

On March 31, 2008, CL&P filed with the DPUC its 2007 CTA and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million. This amount was recorded as a decrease to the CTA regulatory asset on the accompanying condensed consolidated balance sheets. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million. This amount was recorded as a regulatory asset on the accompanying condensed consolidated balance sheets. Management expects a decision in this docket from the DPUC by the end of 2008 and does not expect the outcome to have a material adverse effect on CL&P's net income, financial position or cash flows.

Procurement Fee Rate Proceedings: CL&P was allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) from customers that purchased transitional standard offer (TSO) service from 2004 through the end of 2006. One mill is equal to one tenth of a cent. That fee could increase to 0.75 mills per KWH if CL&P outperforms certain regional benchmarks. CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee and requested approval of $5.8 million in incentive fees. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology as proposed by CL&P and authorized payment of the pre-tax $5.8 million incentive fee. Subsequent to this draft decision the record was re-opened for numerous inputs. Additional hearings were held on December 10, 2007 and January 30, 2008 and the record was then closed. A date for the new draft decision in this docket has not yet been determined by the DPUC. Management continues to believe that final regulatory approval of the $5.8 million pre-tax amount, which was reflected in 2005 earnings, is probable.

New Hampshire:

ES and SCRC Reconciliation and Rates: On an annual basis, PSNH files with the New Hampshire Public Utilities Commission (NHPUC) a default energy service charge/stranded cost recovery charge (ES/SCRC) reconciliation filing for the preceding year. On May 1, 2008, PSNH filed its 2007 ES/SCRC reconciliation with the NHPUC. During 2007, ES/SCRC revenues exceeded ES/SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a regulatory liability to be refunded to customers. The NHPUC is currently reviewing this filing which includes a prudence review of PSNH's generation operations. Testimony filed on October 24, 2008 by the NHPUC's consultant contained no material adverse findings. Hearings are scheduled before the NHPUC in November 2008. Management does not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's net income, financial position or cash flows.

Massachusetts:

Transition Cost Reconciliation: On July 18, 2008, WMECO filed its 2007 transition cost (TC) reconciliation with the Massachusetts Department of Public Utilities (DPU), which compared TC revenue and revenue requirements. For the twelve months ended December 31, 2007, total TC revenues along with carrying charges exceeded TC revenue requirements by $2.6 million, which has been recorded as a regulatory liability on the accompanying condensed consolidated balance sheets. On September 19, 2008, the DPU issued an order of notice for this proceeding, scheduling a public hearing and procedural conference on November 20, 2008. Management does not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.

B.

Long-Term Contractual Arrangements (CL&P)

Estimated Future Annual CL&P Costs: In the third quarter of 2008, UI entered into an additional agreement to purchase energy, capacity and renewable energy credits from a renewable energy facility. CL&P is subject to a sharing agreement with UI, whereby CL&P will share in approximately 80 percent of the costs and benefits of this contract. CL&P s portion of the costs and benefits of this contract will be paid by or refunded to CL&P s customers.

The estimated future annual payments under this agreement, not including the other renewable energy contracts signed earlier this year, are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Total
Renewable energy contracts	$ -	$ -	$ 21.6	$ 25.9	$ 25.9	$ 314.5	$ 387.9

As of September 30, 2008, the estimated future annual costs of CL&P's two signed and approved peaking generation CfDs are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Total
CL&P Peaker CfDs	$ -	$ -	$ 3.4	$ 9.7	$ 10.9	$ 40.0	$ 64.0

C.

Environmental Matters (HWP)

HWP is a subsidiary of NU that owns a minimal amount of transmission property and has limited operating activities. HWP continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in the first nine months of 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of September 30, 2008. The cumulative expense recorded to this reserve through September 30, 2008 was approximately $15.9 million, of which $13.3 million had been spent, leaving approximately $2.6 million in the reserve as of September 30, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, who share responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed plans for additional investigations in conformity with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, management believes that the $2.6 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $2.6 million to $3.3 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2009.

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

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

D.

Guarantees and Indemnifications (All Companies)

NU provides credit assurances on behalf of subsidiaries in the form of guarantees and letters of credit (LOCs) in the normal course of business. NU has also provided guarantees and various indemnifications on behalf of external parties as a result of the sales of Select Energy Services, Inc. (SESI), NU Enterprises' retail marketing business and its competitive generation business. The following table summarizes NU's maximum exposure at September 30, 2008, in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," expiration dates, and fair value of amounts recorded.

Company	Description	Maximum Exposure (in millions)	Expiration Date(s)	Fair Value of Amounts Recorded (in millions)
On behalf of external parties:				
SESI	General indemnifications in connection with the sale of SESI including completeness and accuracy of information provided, compliance with laws, and various claims	Not Specified (1)	None	$ -
	Specific indemnifications in connection with the sale of SESI for estimated costs to complete or modify specific projects	Not Specified (1)	Through project completion	$0.2
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts	$1.5	2017-2018	$0.1
	Surety bonds covering certain projects	$10.5	Through project completion	$ -

Hess Corporation (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, completeness and accuracy of information provided, and various claims	Not Specified	(1)	None	$ -
Energy Capital Partners (Competitive Generation Business)	General indemnifications in connection with the sale of NGC and the generating assets of Mt. Tom including compliance with tax and environmental laws, and various claims	Not Specified	(1)	2008-2009	$ -
On behalf of subsidiaries:					
Regulated Companies	Surety bonds, primarily for self-insurance	$13.6		None	N/A
	Letters of credit	$65.0		2009	N/A
Rocky River Realty Company	Lease payments for real estate	$10.1		2024	N/A
NUSCO	Lease payments for fleet of vehicles	$9.1		None	N/A
E.S. Boulos Company (Boulos)	Surety bonds covering ongoing projects	$36.4		Through project completion	N/A
NGS	Performance guarantee and insurance bonds	$22.1	(2)	2020 (2)	N/A
Select Energy	Performance guarantees and surety bonds for retail marketing contracts	$3.3	(3)	None (4)	N/A
	Performance guarantees for wholesale contracts	$22.0	(3)	2013	N/A
	Letters of credit	$2.0		2009	N/A

(1)

There is no specified maximum exposure included in the related sale agreements.

(2)

Included in the maximum exposure is $20.9 million related to a performance guarantee of Northeast Generation Services Company (NGS) obligations for which there is no specified maximum exposure in the agreement. The maximum exposure is calculated based on limits on NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. The remaining $1.2 million of maximum exposure relates to insurance bonds with no expiration date which are billed annually on their anniversary date.

(3)

Maximum exposure is as of September 30, 2008; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

(4)

NU does not currently anticipate that these remaining guarantees on behalf of Select Energy will result in significant guarantees of the performance of Hess Corporation.

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

In July 2006, under a guarantee of SESI obligations, NU purchased the right to receive contract payments relating to a SESI project that was financed and behind schedule. The carrying value of these assets was $8.8 million at September 30, 2008 and is included in other deferred debits on the accompanying condensed consolidated balance sheets. This carrying amount represents the net realizable value of the asset, which is subject to change through SESI's completion of the project. NU may record additional losses associated with this transaction, the amount of which will depend on the amount of project cash available to offset NU's costs and other factors.

6.

COMPREHENSIVE INCOME (NU, CL&P, PSNH, WMECO, NU Enterprises, Yankee Gas)

Total comprehensive income, which includes all comprehensive income/(loss) items, net of tax and by category, for the three and nine months ended September 30, 2008 and 2007 is as follows:

	Three Months Ended September 30, 2008						
(Millions of Dollars)	**NU***	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**Other**
Net income/(loss)	$ 72.7	$ 54.2	$ 14.3	$ 5.2	$ 4.6	$ (2.3)	$ (3.3)
Comprehensive (loss)/income items:							

Qualified cash flow hedging instruments	(1.1)	0.1	-	-	-	(1.1)	(0.1)
Decrease in unrealized gains on securities	(0.9)	-	-	(0.3)	-	-	(0.6)
Pension, SERP, and other postretirement benefits	0.1	-	-	-	0.1	-	-
Net change in comprehensive (loss)/income items	(1.9)	0.1	-	(0.3)	0.1	(1.1)	(0.7)
Total comprehensive income/(loss)	$ 70.8	$ 54.3	$ 14.3	$ 4.9	$ 4.7	$ (3.4)	$ (4.0)

	Three Months Ended September 30, 2007						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 50.2	$ 33.6	$ 13.0	$ 5.3	$ 0.7	$ (3.4)	$ 1.0
Comprehensive (loss)/income items:							
Qualified cash flow hedging items	(5.2)	(4.6)	-	(0.6)	-	-	-
Decrease in unrealized gains on securities	(0.7)	-	-	(0.1)	-	-	(0.6)
Pension, SERP, and other postretirement benefits	1.7	-	-	-	5.6	-	(3.9)
Net change in comprehensive (loss)/income items	(4.2)	(4.6)	-	(0.7)	5.6	-	(4.5)
Total comprehensive income/(loss)	$ 46.0	$ 29.0	$ 13.0	$ 4.6	$ 6.3	$ (3.4)	$ (3.5)

	Nine Months Ended September 30, 2008						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 188.9	$ 143.7	$ 44.7	$ 14.8	$ 8.7	$ 15.3	$ (38.3)
Comprehensive (loss)/income items:							
Qualified cash flow hedging instruments	(7.0)	(3.5)	(1.4)	(0.1)	-	(1.2)	(0.8)

Decrease in unrealized gains on securities	(1.6)	-	(0.1)	(0.3)	-	-	(1.2)
Pension, SERP, and other postretirement benefits	2.1	-	-	-	1.1	-	1.0
Net change in comprehensive (loss)/income items	(6.5)	(3.5)	(1.5)	(0.4)	1.1	(1.2)	(1.0)
Total comprehensive income/(loss)	$ 182.4	$ 140.2	$ 43.2	$ 14.4	$ 9.8	$ 14.1	$ (39.3)

	Nine Months Ended September 30, 2007						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income	$ 173.8	$ 91.6	$ 38.2	$ 16.8	$ 8.1	$ 10.5	$ 8.6
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	(6.8)	(6.2)	-	(0.7)	-	-	0.1
Increase/(decrease) in unrealized gains on securities	0.6	-	-	(0.1)	-	-	0.7
Pension, SERP, and other postretirement benefits	8.0	-	-	-	9.4	-	(1.4)
Net change in comprehensive income/(loss) items	1.8	(6.2)	-	(0.8)	9.4	-	(0.6)
Total comprehensive income	$ 175.6	$ 85.4	$ 38.2	$ 16.0	$ 17.5	$ 10.5	$ 8.0

*After preferred dividends of subsidiary.

Comprehensive income amounts included in the Other column primarily relate to NU parent and Northeast Utilities Service Company (NUSCO).

Accumulated other comprehensive income fair value adjustments in NU's qualified cash flow hedging instruments for the nine months ended September 30, 2008 and the twelve months ended December 31, 2007 are as follows:

(Millions of Dollars, Net of Tax)	Nine Months Ended September 30, 2008	Twelve Months Ended December 31, 2007
Balance at beginning of period	$ 2.3	$ 5.9
Hedged transactions recognized into earnings	0.3	0.2
Change in fair value of interest rate swap agreements	(7.0)	-

Cash flow transactions entered into for the period	(0.3)	(3.8)
Net change associated with hedging transactions	(7.0)	(3.6)
Total fair value adjustments included in accumulated other comprehensive income	$ (4.7)	$ 2.3

The following table provides the forward starting interest rate swap transactions entered into by the company, CL&P, PSNH and Yankee Gas to hedge interest rate risk associated with their respective long-term debt issuances and terminated in March, May, June and September 2008:

	NU Parent	**CL&P**	**PSNH**	**Yankee Gas**
Long-term debt issued (in millions)	$250	$300	$110	$100
Date issued	June 5, 2008	May 27, 2008	May 27, 2008	October 7, 2008
Term	5-year	10-year	10-year	10-year
Loaded LIBOR swap percentage rate(s) (percentage)	4.102 (1)	4.590 and 4.602 (2)	4.5575 and 4.147 (3)	4.635 and 4.5685 (4)
Charge to accumulated other comprehensive income (net of tax) (5)	0.1	2.3	0.9 (6)	0.7

(1)

The interest rate swap was entered into with a notional amount of $200 million.

(2)

The two locked rates reflect two forward starting interest rate swap transactions, each with a notional amount of $150 million.

(3)

The first swap transaction was entered into in December 2007 and was replaced at its scheduled termination date in March 2008 with a new swap to extend the hedging relationship to the revised pricing date of the long-term debt in May 2008.

(4)

The first swap transaction was entered into in December 2007 and was replaced at its scheduled termination date in September 2008 with a new swap to extend the hedging relationship to the revised pricing date of the long-term debt in October 2008. On September 26, 2008, the debt was priced and the second swap was unwound.

(5)

The charge to accumulated other comprehensive income will be amortized into earnings over the terms of each respective long-term debt.

(6)

The amount charged to accumulated other comprehensive income is net of ineffectiveness of $0.2 million related to the settlement of the March 2008 forward starting swap agreement.

It is estimated that a charge of $0.2 million will be reclassified from accumulated other comprehensive income as a decrease to earnings over the next 12 months as a result of amortization of amounts due to forward interest rate swap agreements that have been settled. At September 30, 2008, it is estimated that a pre-tax $0.1 million included in the accumulated other comprehensive income balance will be reclassified as an increase to earnings over the next 12 months related to Pension, SERP and other postretirement benefits adjustments.

7.

DISCONTINUED OPERATIONS (NU, NU Enterprises)

NU's condensed consolidated statements of income present NGC, Mt. Tom and SECI as discontinued operations. Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified in loss from discontinued operations on the condensed consolidated statements of income, for all periods presented.

Summarized information for the discontinued operations is as follows:

	For the Three Months Ended		**For the Nine Months Ended**	
(Millions of Dollars)	**September 30, 2008**	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Operating revenues	$ -	$ 0.1	$ -	$ 1.2
Operating expenses	-	(0.1)	-	(0.9)
Income from discontinued operations	-	-	-	0.3
(Losses)/gains from sale/disposition of discontinued operations	-	(0.1)	-	1.9
Income tax benefit/(expense) from discontinued operations	-	0.1	-	(1.0)
Net income from discontinued operations	-	-	-	1.2

The gain on sale/disposition of discontinued operations of $1.9 million for the nine months ended September 30, 2007 was primarily due to the favorable resolution of contingencies from the completion of a cogeneration plant by SESI, which was sold in May of 2006, partially offset by charges related to the sale of the competitive generation business, including a $1.9 million charge in the first quarter resulting from a purchase price adjustment from the sale of the competitive generation business.

No intercompany revenues were included in discontinued operations for either of the three and nine months ended September 30, 2008 and 2007.

At September 30, 2008, NU did not have and does not expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

8.

EARNINGS PER SHARE (NU)

Earnings per share (EPS) is computed based upon the weighted average number of common shares outstanding, excluding unallocated Employee Stock Ownership Plan (ESOP) shares, during each period. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. There were no antidilutive options for any of the three- and nine-month periods ended September 30, 2008 and 2007.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars, Except for Share Information)	2008	2007	2008	2007
Income from continuing operations	$ 72.7	$ 50.2	$ 188.9	$ 172.6
Income from discontinued operations	-	-	-	1.2
Net income	$ 72.7	$ 50.2	$ 188.9	$ 173.8
Basic EPS common shares outstanding (average)	155,607,201	154,930,930	155,456,606	154,672,270
Dilutive effect	490,440	489,309	448,265	538,434
Fully diluted EPS common shares outstanding (average)	156,097,641	155,420,239	155,904,871	155,210,704
Basic EPS:				
Income from continuing operations	$ 0.47	$ 0.32	$ 1.22	$ 1.12
Income from discontinued operations	-	-	-	-
Net income	$ 0.47	$ 0.32	$ 1.22	$ 1.12
Fully Diluted EPS:				
Income from continuing operations	$ 0.47	$ 0.32	$ 1.21	$ 1.11
Income from discontinued operations	-	-	-	0.01
Net income	$ 0.47	$ 0.32	$ 1.21	$ 1.12

The dilutive effect of restricted share units (RSUs) granted but not issued is calculated using the treasury stock method. Assumed proceeds of RSUs 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 RSUs (the difference between the market value of RSUs using the average market price during the period and the grant date market value).

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

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

9.

SEGMENT INFORMATION (All Companies)

Presentation: NU is organized between the regulated companies and NU Enterprises' businesses based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which each 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 and the capitalized portion of pension expense or income. Segment information for all periods presented has been reclassified to conform to the current period presentation, except as indicated.

The regulated companies segments, including the electric distribution, generation and transmission segments, as well as the gas distribution segment (Yankee Gas), represented approximately 99 percent of NU's total revenues for the three and nine months ended September 30, 2008 as compared to 96 percent for the 2007 periods. CL&P's, PSNH's and WMECO's complete condensed consolidated financial statements are included in this combined quarterly report on Form 10-Q. PSNH's distribution segment includes generation activities. Also included in this combined quarterly report on Form 10-Q is detailed information regarding CL&P's, PSNH's, and WMECO's transmission segments.

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

Other in the segment tables primarily consists of 1) the results of NU parent, which include 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 NUSCO, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which include The Rocky River Realty Company and The Quinnehtuk Company (real estate subsidiaries), Mode 1 Communications, Inc., the non-utility subsidiaries of Yankee Energy System, Inc. (Yankee Energy Services Company, Yankee Energy Financial Services Company and NorConn Properties, Inc.) and the remaining operations of HWP that were not exited as part of the sale of the competitive generation business.

NU's condensed consolidated statements of income for the three and nine months ended September 30, 2007 present the remaining activity for NGC, Mt. Tom and SECI as discontinued operations. For further information and information regarding the exit from these businesses, see Note 7, "Discontinued Operations," to the condensed consolidated financial statements.

NU's segment information for the three and nine months ended September 30, 2008 and 2007 is as follows (certain amounts presented in the financial statements may differ from amounts presented in the segment schedules due to rounding):

For the Three Months Ended September 30, 2008							
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,283.8	$ 92.3	$ 110.0	$ 23.1	$ 106.2	$ (108.5)	$ 1,506.9
Depreciation and amortization	(161.9)	(6.7)	(12.8)	(0.2)	(2.8)	0.2	(184.2)
Other operating expenses	(1,044.4)	(84.5)	(36.4)	(16.4)	(96.1)	104.2	(1,173.6)
Operating income/(loss)	77.5	1.1	60.8	6.5	7.3	(4.1)	149.1
Interest expense, net of AFUDC	(41.8)	(5.1)	(14.4)	(1.3)	(10.9)	2.6	(70.9)
Interest income	11.1	0.4	0.2	0.4	2.5	(2.6)	12.0
Other income, net	(0.6)	-	6.4	-	33.0	(33.1)	5.7
Income tax (expense)/benefit	(7.5)	1.3	(16.6)	(1.0)	2.0	-	(21.8)
Preferred dividends	(0.9)	-	(0.5)	-	-	-	(1.4)
Net income	$ 37.8	$ (2.3)	$ 35.9	$ 4.6	$ 33.9	$ (37.2)	$ 72.7

For the Nine Months Ended September 30, 2008							
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 3,580.6	$ 404.9	$ 306.3	$ 87.0	$ 306.3	$ (332.9)	$ 4,352.2

Depreciation and amortization	(427.7)	(19.7)	(35.1)	(0.4)	(10.0)	0.6	(492.3)
Other operating expenses	(2,915.0)	(346.1)	(101.6)	(70.8)	(332.2)	325.3	(3,440.4)
Operating income/(loss)	237.9	39.1	169.6	15.8	(35.9)	(7.0)	419.5
Interest expense, net of AFUDC	(122.0)	(15.2)	(39.7)	(4.3)	(25.9)	7.5	(199.6)
Interest income	12.9	0.4	2.3	0.9	6.4	(8.4)	14.5
Other income, net	4.8	0.1	22.1	-	143.4	(143.3)	27.1
Income tax (expense)/benefit	(31.3)	(9.1)	(49.2)	(3.7)	26.0	(1.1)	(68.4)
Preferred dividends	(2.7)	-	(1.5)	-	-	-	(4.2)
Net income	$ 99.6	$ 15.3	$ 103.6	$ 8.7	$ 114.0	$ (152.3)	$ 188.9
Total assets (2)	$ 11,081.3	$ 1,326.8	$ -	$ 48.9	$ 4,377.7	$ (4,171.0)	$ 12,663.7
Cash flows for total investments in plant	$ 326.3	$ 39.1	$ 566.7	$ -	$ 19.7	$ -	$ 951.8

For the Three Months Ended September 30, 2007

(Millions of Dollars)	Regulated Companies Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,243.3	$ 71.7	$ 72.9	$ 68.3	$ 93.2	$ (98.4)	$ 1,451.0
Depreciation and amortization	(116.6)	(6.8)	(9.6)	(0.2)	(2.0)	1.2	(134.0)
Other operating expenses	(1,043.4)	(64.3)	(29.0)	(65.9)	(87.6)	96.6	(1,193.6)
Operating income	83.3	0.6	34.3	2.2	3.6	(0.6)	123.4
Interest expense, net of AFUDC	(43.2)	(5.1)	(8.9)	(1.9)	(8.3)	5.6	(61.8)
Interest income	1.0	-	0.4	0.6	7.1	(5.6)	3.5
Other income/(loss), net	2.9	-	3.8	-	27.2	(26.6)	7.3
Income tax (expense)/benefit	(11.1)	1.1	(9.2)	(0.2)	(0.9)	(0.5)	(20.8)
Preferred dividends	(1.0)	-	(0.4)	-	-	-	(1.4)
Income/(loss) from continuing operations	31.9	(3.4)	20.0	0.7	28.7	(27.7)	50.2

Income from discontinued operations	-	-	-	-	-	-	-
Net income/(loss)	$ 31.9	$ (3.4)	$ 20.0	$ 0.7	$ 28.7	$ (27.7)	$ 50.2

	For the Nine Months Ended September 30, 2007						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 3,784.7	$ 351.5	$ 214.7	$ 220.4	$ 287.1	$ (312.1)	$ 4,546.3
Depreciation and amortization	(312.7)	(18.4)	(27.8)	(0.5)	(6.1)	3.0	(362.5)
Other operating expenses	(3,230.6)	(303.9)	(84.4)	(206.0)	(269.3)	306.3	(3,787.9)
Operating income	241.4	29.2	102.5	13.9	11.7	(2.8)	395.9
Interest expense, net of AFUDC	(127.1)	(13.6)	(26.0)	(7.1)	(25.4)	18.6	(180.6)
Interest income	3.1	0.1	1.4	1.9	27.3	(18.4)	15.4
Other income, net	10.9	1.0	7.7	-	113.1	(111.4)	21.3
Income tax expense	(35.7)	(6.2)	(27.4)	(1.8)	(2.6)	(1.5)	(75.2)
Preferred dividends	(3.0)	-	(1.2)	-	-	-	(4.2)
Income from continuing operations	89.6	10.5	57.0	6.9	124.1	(115.5)	172.6
Income from discontinued operations	-	-	-	1.2	-	-	1.2
Net income	$ 89.6	$ 10.5	$ 57.0	$ 8.1	$ 124.1	$ (115.5)	$ 173.8
Cash flows for total investments in plant	$ 259.5	$ 43.3	$ 436.5	$ 6.8	$ 4.1	$ -	$ 750.2

(1)

Includes PSNH's generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at September 30, 2008. On an NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution columns above.

The regulated companies information related to the distribution and transmission segments for CL&P, PSNH and WMECO for the three and nine months ended September 30, 2008 and 2007 is as follows:

	CL&P - For the Three Months Ended September 30, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 891.0	$ 89.5	$ 980.5
Depreciation and amortization	(123.9)	(10.3)	(134.2)
Other operating expenses	(720.6)	(27.5)	(748.1)
Operating income	46.5	51.7	98.2
Interest expense, net of AFUDC	(25.7)	(12.4)	(38.1)
Interest income	7.3	0.5	7.8
Other income, net	(0.2)	5.5	5.3
Income tax expense	(3.5)	(14.1)	(17.6)
Preferred dividends	(0.9)	(0.5)	(1.4)
Net income	$ 23.5	$ 30.7	$ 54.2

	CL&P - For the Nine Months Ended September 30, 2008		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 2,444.8	$ 243.1	$ 2,687.9
Depreciation and amortization	(332.7)	(27.9)	(360.6)
Other operating expenses	(1,975.5)	(74.2)	(2,049.7)
Operating income	136.6	141.0	277.6
Interest expense, net of AFUDC	(75.4)	(34.1)	(109.5)
Interest income	8.6	1.8	10.4
Other income, net	4.7	19.7	24.4
Income tax expense	(14.6)	(40.4)	(55.0)
Preferred dividends	(2.7)	(1.5)	(4.2)
Net income	$ 57.2	$ 86.5	$ 143.7
Cash flows for total investments in plant	$ 200.6	$ 478.0	$ 678.6

	CL&P - For the Three Months Ended September 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 862.5	$ 55.9	$ 918.4
Depreciation and amortization	(73.0)	(7.4)	(80.4)
Other operating expenses	(745.0)	(21.6)	(766.6)
Operating income	44.5	26.9	71.4
Interest expense, net of AFUDC	(28.0)	(7.6)	(35.6)
Interest income	0.8	0.3	1.1
Other income, net	2.6	3.9	6.5
Income tax expense	(2.2)	(6.2)	(8.4)
Preferred dividends	(1.0)	(0.4)	(1.4)
Net income	$ 16.7	$ 16.9	$ 33.6

	CL&P - For the Nine Months Ended September 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 2,668.0	$ 164.5	$ 2,832.5
Depreciation and amortization	(211.6)	(21.5)	(233.1)
Other operating expenses	(2,324.2)	(60.9)	(2,385.1)
Operating income	132.2	82.1	214.3
Interest expense, net of AFUDC	(82.0)	(21.6)	(103.6)
Interest income	2.2	1.2	3.4
Other income, net	9.7	7.3	17.0
Income tax expense	(14.8)	(20.5)	(35.3)
Preferred dividends	(3.0)	(1.2)	(4.2)
Net income	$ 44.3	$ 47.3	$ 91.6
Cash flows for total investments in plant	$ 166.5	$ 383.6	$ 550.1

	PSNH - For the Three Months Ended September 30, 2008		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Total**
Operating revenues	$ 286.9	$ 14.1	$ 301.0
Depreciation and amortization	(26.5)	(1.9)	(28.4)
Other operating expenses	(237.1)	(6.1)	(243.2)
Operating income	23.3	6.1	29.4
Interest expense, net of AFUDC	(11.8)	(1.6)	(13.4)

Interest income		2.3		-		2.3
Other income, net		(0.2)		0.6		0.4
Income tax expense		(2.9)		(1.5)		(4.4)
Net income	$	10.7	$	3.6	$	14.3

	PSNH - For the Nine Months Ended September 30, 2008					
(Millions of Dollars)	**Distribution (1)**		**Transmission**		**Total**	
Operating revenues	$	822.8	$	44.0	$	866.8
Depreciation and amortization		(61.2)		(5.3)		(66.5)
Other operating expenses		(687.6)		(18.4)		(706.0)
Operating income		74.0		20.3		94.3
Interest expense, net of AFUDC		(33.6)		(3.9)		(37.5)
Interest income		2.6		0.4		3.0
Other income, net		0.4		1.9		2.3
Income tax expense		(11.1)		(6.3)		(17.4)
Net income	$	32.3	$	12.4	$	44.7
Cash flows for total investments in plant	$	101.5	$	63.3	$	164.8

	PSNH - For the Three Months Ended September 30, 2007		
(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	$ 272.8	$ 11.5	$ 284.3
Depreciation and amortization	(32.6)	(1.5)	(34.1)
Other operating expenses	(212.6)	(4.9)	(217.5)
Operating income	27.6	5.1	32.7
Interest expense, net of AFUDC	(10.9)	(0.8)	(11.7)
Interest income	0.1	-	0.1
Income tax expense	(5.8)	(2.3)	(8.1)
Net income	$ 11.0	$ 2.0	$ 13.0

	PSNH - For the Nine Months Ended September 30, 2007		
(Millions of Dollars)	Distribution (1)	Transmission	Total
Operating revenues	$ 778.2	$ 33.5	$ 811.7
Depreciation and amortization	(70.3)	(4.4)	(74.7)
Other operating expenses	(633.4)	(15.3)	(648.7)
Operating income	74.5	13.8	88.3
Interest expense, net of AFUDC	(31.9)	(2.9)	(34.8)
Interest income	0.4	0.1	0.5
Other income, net	0.7	0.4	1.1
Income tax expense	(12.0)	(4.9)	(16.9)
Net income	$ 31.7	$ 6.5	$ 38.2
Cash flows for total investments in plant	$ 71.9	$ 41.2	$ 113.1

(1)

Includes PSNH's generation activities.

	WMECO - For the Three Months Ended September 30, 2008		
(Millions of Dollars)	Distribution	Transmission	Total
Operating revenues	$ 105.9	$ 6.4	$ 112.3
Depreciation and amortization	(11.4)	(0.7)	(12.1)
Other operating expenses	(86.8)	(2.6)	(89.4)

Operating income		7.7		3.1		10.8
Interest expense, net of AFUDC		(4.3)		(0.4)		(4.7)
Interest income		1.4		(0.3)		1.1
Other income, net		(0.2)		0.3		0.1
Income tax expense		(1.0)		(1.1)		(2.1)
Net income	$	3.6	$	1.6	$	5.2

	WMECO - For the Nine Months Ended September 30, 2008					
(Millions of Dollars)	**Distribution**		**Transmission**		**Total**	
Operating revenues	$	313.2	$	19.1	$	332.3
Depreciation and amortization		(33.8)		(2.0)		(35.8)
Other operating expenses		(252.1)		(8.8)		(260.9)
Operating income		27.3		8.3		35.6
Interest expense, net of AFUDC		(13.1)		(1.6)		(14.7)
Interest income		1.7		-		1.7
Other income, net		(0.2)		0.5		0.3
Income tax expense		(5.6)		(2.5)		(8.1)
Net income	$	10.1	$	4.7	$	14.8
Cash flows for total investments in plant	$	24.2	$	25.4	$	49.6

	WMECO - For the Three Months Ended September 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 108.1	$ 5.4	$ 113.5
Depreciation and amortization	(11.0)	(0.6)	(11.6)
Other operating expenses	(85.8)	(2.5)	(88.3)
Operating income	11.3	2.3	13.6
Interest expense, net of AFUDC	(4.3)	(0.5)	(4.8)
Interest income	0.2	-	0.2
Income tax expense	(3.0)	(0.7)	(3.7)
Net income	$ 4.2	$ 1.1	$ 5.3

	WMECO - For the Nine Months Ended September 30, 2007		
(Millions of Dollars)	**Distribution**	**Transmission**	**Total**
Operating revenues	$ 338.7	$ 16.7	$ 355.4
Depreciation and amortization	(30.8)	(1.9)	(32.7)
Other operating expenses	(273.2)	(8.2)	(281.4)
Operating income	34.7	6.6	41.3
Interest expense, net of AFUDC	(13.2)	(1.5)	(14.7)
Interest income	0.5	0.1	0.6
Other income, net	0.6	0.1	0.7
Income tax expense	(9.0)	(2.1)	(11.1)
Net income	$ 13.6	$ 3.2	$ 16.8
Cash flows for total investments in plant	$ 21.1	$ 11.7	$ 32.8

10.

SUBSEQUENT EVENTS

On October 7, 2008, Yankee Gas issued $100 million of Series J first mortgage bonds with a coupon rate of 6.9 percent and a maturity date of October 1, 2018. The proceeds from this issuance will be used to repay short-term debt, to fund ongoing capital investment programs and for general working capital purposes.

On October 1, 2008, CL&P reacquired $62 million of PCRBs that had a fixed rate mode which terminated effective September 30, 2008. The reacquisition of the PCRBs will be accounted for as a reduction of the September 30, 2008 balance of long-term debt - current portion.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have reviewed the accompanying condensed consolidated balance sheet of Northeast Utilities and subsidiaries (the "Company") as of September 30, 2008, and the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2008 and 2007, and of cash flows for the nine-month periods ended September 30, 2008 and 2007. These interim financial statements are the responsibility of the Company s management.

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

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

As discussed in Notes 1.C. and 3., the Company adopted Statement of Financial Accounting Standard No. 157, *Fair Value Measurements*, as of January 1, 2008.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and consolidated statement of capitalization of Northeast Utilities and subsidiaries as of December 31, 2007, and the related consolidated statements of income, comprehensive income, shareholders equity, and cash flows for the year then ended (not presented herein); and in our report dated February 28, 2008 (which report included an explanatory paragraph related to the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*, as of January 1, 2007), we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2007 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut

November 7, 2008

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THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 6,096	$ 538
Investments in securitizable assets (Note 1E)	-	308,182
Receivables, less provision for uncollectible accounts of $22,059 in 2008 and $7,874 in 2007	396,408	118,342
Notes receivable from affiliated companies	16,075	-
Accounts receivable from affiliated companies	2,917	3,339
Unbilled revenues	122,200	8,225
Taxes receivable	-	16,245
Materials and supplies	69,172	55,477
Derivative assets - current	37,428	57,003
Prepayments and other	35,841	17,387
	686,137	584,738
Property, Plant and Equipment:		
Electric utility	5,503,016	4,899,075
Less: Accumulated depreciation	1,331,493	1,279,697
	4,171,523	3,619,378
Construction work in progress	775,852	782,468
	4,947,375	4,401,846
Deferred Debits and Other Assets:		

Regulatory assets	1,684,429	1,329,963
Prepaid pension	358,145	334,786
Derivative assets - long-term	250,174	278,726
Other	83,480	88,040
	2,376,228	2,031,515
Total Assets	$ 8,009,740	$ 7,018,099

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 187,973	$ -
Notes payable to affiliated companies	-	38,825
Long-term debt - current portion	62,000	-
Accounts payable	289,778	368,356
Accounts payable to affiliated companies	52,614	53,096
Accrued taxes	50,741	-
Accrued interest	38,481	29,532
Derivative liabilities - current	5,366	4,234
Other	102,951	107,940
	789,904	601,983
Rate Reduction Bonds	419,834	548,686
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	781,408	698,789
Accumulated deferred investment tax credits	19,457	21,412
Deferred contractual obligations	135,768	152,735
Regulatory liabilities	440,877	601,455
Derivative liabilities - long-term	715,950	135,991
Accrued postretirement benefits	70,256	78,587
Other	209,984	191,464
	2,373,700	1,880,433
Capitalization:		
Long-Term Debt	2,269,765	2,028,546

Preferred Stock - Non-Redeemable	116,200	116,200
Common Stockholder's Equity:		
Common stock, $10 par value - authorized		
24,500,000 shares; 6,035,205 shares outstanding		
in 2008 and 2007	60,352	60,352
Capital surplus, paid in	1,381,688	1,243,940
Retained earnings	601,981	538,138
Accumulated other comprehensive loss	(3,684)	(179)
Common Stockholder's Equity	2,040,337	1,842,251
Total Capitalization	4,426,302	3,986,997
Commitments and Contingencies (Note 5)		
Total Liabilities and Capitalization	$ 8,009,740	$ 7,018,099

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 980,507	$ 918,418	$ 2,687,881	$ 2,832,483
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	522,613	604,953	1,414,506	1,809,996
Other	140,727	87,946	402,099	365,184
Maintenance	35,863	29,391	98,297	80,281
Depreciation	40,740	38,354	119,464	114,818
Amortization of regulatory assets, net	55,105	6,156	131,093	15,493
Amortization of rate reduction bonds	38,353	35,904	110,033	102,833
Taxes other than income taxes	48,953	44,291	134,787	129,540
Total operating expenses	882,354	846,995	2,410,279	2,618,145
Operating Income	98,153	71,423	277,602	214,338
Interest Expense:				
Interest on long-term debt	28,053	21,457	77,052	60,637
Interest on rate reduction bonds	6,997	9,230	22,808	29,097
Other interest	3,074	4,897	9,635	13,849
Interest expense, net	38,124	35,584	109,495	103,583

Other Income, Net	13,059	7,545	34,757	20,275
Income Before Income Tax Expense	73,088	43,384	202,864	131,030
Income Tax Expense	17,553	8,408	55,006	35,274
Net Income	$ 55,535	$ 34,976	$ 147,858	$ 95,756

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

THE CONNECTICUT LIGHT AND POWER
COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED
STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2008	2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 147,858	$ 95,756
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	5,450	13,720
Depreciation	119,464	114,818
Deferred income taxes	18,313	(27,738)
Pension income, net of capitalized portion	(8,508)	(6,570)
Amortization of recoverable energy costs	-	3,096
Amortization of rate reduction bonds	110,033	102,833
Amortization of regulatory assets, net	131,093	15,493
Regulatory (refunds and underrecoveries)/overrecoveries	(99,900)	66,976
Settlement of cash flow hedge instruments	(3,890)	-
Deferred contractual obligations	(16,967)	(21,915)
Other non-cash adjustments	(25,075)	(13,382)
Other uses of cash	(10,994)	(24,703)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(68,702)	(13,984)
Materials and supplies	(13,700)	(15,009)
Investments in securitizable assets	(25,787)	18,138
Other current assets	(18,642)	(15,798)
Accounts payable	(25,626)	(34,858)
Taxes receivable/accrued	102,146	(162,843)
Other current liabilities	14,468	7,755
Net cash flows provided by operating activities	331,034	101,785

Investing Activities:				
Investments in property and plant		(678,616)		(550,128)
Increase in NU Money Pool lending		(16,075)		-
Proceeds from sales of investment securities		2,061		1,515
Purchases of investment securities		(2,110)		(1,565)
Rate reduction bond escrow and other deposits		(1,607)		3,741
Other investing activities		623		680
Net cash flows used in investing activities		(695,724)		(545,757)
Financing Activities:				
Issuance of long-term debt		300,000		500,000
Retirement of rate reduction bonds		(128,852)		(114,411)
Increase in short-term debt		187,973		-
Decrease in NU Money Pool borrowings		(38,825)		(128,400)
Capital contributions from NU parent		137,430		265,000
Cash dividends on preferred stock		(4,169)		(4,169)
Cash dividends on common stock		(79,846)		(59,386)
Other financing activities		(3,463)		(7,303)
Net cash flows provided by financing activities		370,248		451,331
Net increase in cash		5,558		7,359
Cash - beginning of period		538		3,310
Cash - end of period	$	6,096	$	10,669

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED
BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 3,107	$ 450
Receivables, less provision for uncollectible accounts of $3,764 in 2008 and $2,675 in 2007	99,620	97,749
Notes receivable from affiliated companies	6,100	-
Accounts receivable from affiliated companies	1,166	817
Unbilled revenues	45,407	45,607
Taxes receivable	21,593	255
Fuel, materials and supplies	70,490	72,215
Derivative assets - current	2,469	6,146
Prepayments and other	25,827	14,327
	275,779	237,566
Property, Plant and Equipment:		
Electric utility	2,168,429	2,010,220
Less: Accumulated depreciation	773,172	737,917
	1,395,257	1,272,303
Construction work in progress	112,588	116,102
	1,507,845	1,388,405
Deferred Debits and Other Assets:		
Regulatory assets	407,327	401,374
Derivative assets - long-term	8,023	12,075
Other	68,518	67,549

		483,868		480,998
Total Assets	$	2,267,492	$	2,106,969

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ -	$ 10,000
Notes payable to affiliated companies	-	11,300
Accounts payable	80,373	91,356
Accounts payable to affiliated companies	9,602	15,717
Accrued interest	16,197	9,175
Derivative liabilities - current	39,895	2,453
Other	21,861	22,664
	167,928	162,665
Rate Reduction Bonds	246,958	282,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	217,033	192,094
Accumulated deferred investment tax credits	412	582
Deferred contractual obligations	24,151	28,215
Regulatory liabilities	95,584	127,569
Derivative liabilities - long-term	12,623	-
Accrued pension	147,639	138,346
Accrued postretirement benefits	26,378	29,057
Other	41,547	31,559
	565,367	547,422
Capitalization:		
Long-Term Debt	686,766	576,997
Common Stockholder's Equity:		

Common stock, $1 par value - authorized				
100,000,000 shares; 301 shares outstanding				
in 2008 and 2007		-		-
Capital surplus, paid in		322,277		275,569
Retained earnings		278,944		261,528
Accumulated other comprehensive (loss)/income		(748)		770
Common Stockholder's Equity		600,473		537,867
Total Capitalization		1,287,239		1,114,864
Commitments and Contingencies (Note 5)				
Total Liabilities and Capitalization	$	2,267,492	$	2,106,969

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 301,033	$ 284,326	$ 866,837	$ 811,655
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	159,255	140,881	443,690	409,493
Other	46,159	49,584	155,266	152,123
Maintenance	26,814	16,621	75,987	56,733
Depreciation	14,331	13,702	41,553	40,345
Amortization of regulatory assets/(liabilities), net	2,671	7,027	(9,240)	(4,682)
Amortization of rate reduction bonds	11,439	13,374	34,186	38,977
Taxes other than income taxes	11,000	10,471	31,121	30,355
Total operating expenses	271,669	251,660	772,563	723,344
Operating Income	29,364	32,666	94,274	88,311
Interest Expense:				
Interest on long-term debt	9,089	6,211	24,088	18,616
Interest on rate reduction bonds	3,948	4,441	12,180	13,752

Other interest		362		1,066	1,252	2,446
Interest expense, net		13,399		11,718	37,520	34,814
Other Income, Net		2,706		205	5,294	1,598
Income Before Income Tax Expense		18,671		21,153	62,048	55,095
Income Tax Expense		4,353		8,137	17,350	16,867
Net Income	$	14,318	$	13,016	$ 44,698	$ 38,228

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2008	2007
	(Thousands of Dollars)	
Operating activities:		
Net income	$ 44,698	$ 38,228
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	3,992	2,269
Depreciation	41,553	40,345
Deferred income taxes	10,164	(11,287)
Pension expense, net of capitalized portion	10,218	11,294
Amortization of rate reduction bonds	34,186	38,977
Amortization of regulatory liabilities, net	(9,240)	(4,682)
Regulatory refunds and underrecoveries	(3,873)	(4,248)
Net settlement of cash flow hedge instruments	(1,730)	-
Deferred contractual obligations	(4,064)	(4,924)
Other non-cash adjustments	(7,694)	(3,470)
Other uses of cash	(10,014)	(8,392)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(6,012)	(4,065)
Taxes receivable/accrued	(14,901)	10,336
Fuel, materials and supplies	1,725	3,261
Other current assets	20	2,634
Accounts payable	(933)	(4,988)
Accrued interest	8,009	4,417
Other current liabilities	3,627	3,723
Net cash flows provided by operating activities	99,731	109,428

Investing Activities:

Investments in property and plant		(164,757)		(113,132)
Increase in NU Money Pool lending		(6,100)		(7,300)
Proceeds from sales of investment securities		3,532		2,596
Purchases of investment securities		(3,616)		(2,682)
Other investing activities		2,551		(667)
Net cash flows used in investing activities		(168,390)		(121,185)
Financing Activities:				
Issuance of long-term debt		110,000		70,000
Decrease in short-term debt		(10,000)		-
Retirement of rate reduction bonds		(35,060)		(37,975)
Increase in NU Money Pool borrowings		(11,300)		(36,500)
Capital contributions from NU parent		46,583		43,763
Cash dividends on common stock		(27,282)		(23,040)
Other financing activities		(1,625)		(1,214)
Net cash flows provided by financing activities		71,316		15,034
Net increase in cash		2,657		3,277
Cash - beginning of period		450		31
Cash - end of period	$	3,107	$	3,308

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2008	December 31, 2007
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 2,634	$ 1,110
Receivables, less provision for uncollectible accounts of $6,843 in 2008 and $5,699 in 2007	49,741	49,578
Accounts receivable from affiliated companies	1,063	258
Unbilled revenues	14,252	17,990
Taxes receivable	15,578	3,382
Materials and supplies	3,980	2,353
Marketable securities - current	46,170	31,286
Prepayments and other	4,790	2,661
	138,208	108,618
Property, Plant and Equipment:		
Electric utility	751,736	728,712
Less: Accumulated depreciation	211,897	205,743
	539,839	522,969
Construction work in progress	57,259	36,388
	597,098	559,357
Deferred Debits and Other Assets:		
Regulatory assets	162,224	193,921
Prepaid pension	95,578	90,015

Marketable securities - long-term	9,541	25,078
Other	14,139	14,099
	281,482	323,113
Total Assets	$ 1,016,788	$ 991,088

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

		September 30, 2008		December 31, 2007
		(Thousands of Dollars)		
LIABILITIES AND CAPITALIZATION				
Current Liabilities:				
Notes payable to banks	$	19,900	$	-
Notes payable to affiliated companies		10,900		14,900
Accounts payable		33,087		30,636
Accounts payable to affiliated companies		11,955		7,480
Accrued interest		2,281		5,498
Other		10,107		10,489
		88,230		69,003
Rate Reduction Bonds		76,553		86,731
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		187,253		187,139
Accumulated deferred investment tax credits		1,818		2,015
Deferred contractual obligations		37,385		41,958
Regulatory liabilities		33,510		39,437
Accrued postretirement benefits		11,291		12,668
Other		12,428		5,015
		283,685		288,232
Capitalization:				
Long-Term Debt		304,432		303,872

Common Stockholder's Equity:			
Common stock, $25 par value - authorized			
1,072,471 shares; 434,653 shares outstanding			
in 2008 and 2007		10,866	10,866
Capital surplus, paid in		144,557	128,228
Retained earnings		108,625	103,925
Accumulated other comprehensive (loss)/income		(160)	231
Common Stockholder's Equity		263,888	243,250
Total Capitalization		568,320	547,122
Commitments and Contingencies (Note 5)			
Total Liabilities and Capitalization	$	1,016,788	$ 991,088

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(Thousands of Dollars)			
Operating Revenues	$ 112,280	$ 113,500	$ 332,254	$ 355,421
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	64,146	56,555	177,640	184,462
Other	16,255	23,863	57,830	73,327
Maintenance	5,807	4,927	15,856	14,244
Depreciation	5,183	5,341	15,627	15,827
Amortization of regulatory assets, net	3,541	3,202	9,950	7,417
Amortization of rate reduction bonds	3,341	3,124	10,148	9,506
Taxes other than income taxes	3,236	2,926	9,610	9,327
Total operating expenses	101,509	99,938	296,661	314,110
Operating Income	10,771	13,562	35,593	41,311
Interest Expense:				
Interest on long-term debt	3,278	2,960	9,964	8,265
Interest on rate reduction bonds	1,262	1,440	3,922	4,451
Other interest	197	410	822	1,938

Interest expense, net	4,737	4,810	14,708	14,654
Other Income, Net	1,329	312	2,053	1,248
Income Before Income Tax Expense	7,363	9,064	22,938	27,905
Income Tax Expense	2,127	3,724	8,133	11,058
Net Income	$ 5,236	$ 5,340	$ 14,805	$ 16,847

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 14,805	$ 16,847
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	6,123	5,258
Depreciation	15,627	15,827
Deferred income taxes	6,487	(12,671)
Pension income, net of capitalized portion	(2,811)	(2,342)
Amortization of rate reduction bonds	10,148	9,506
Amortization of regulatory assets, net	9,950	7,417
Regulatory (underrecoveries)/overrecoveries	(1,317)	32,229
Deferred contractual obligations	(4,573)	(5,922)
Other non-cash adjustments	(2,995)	(2,034)
Other sources of cash	-	556
Other uses of cash	(2,028)	(1,215)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	(3,171)	(11,637)
Materials and supplies	(1,645)	(252)
Other current assets	(1,578)	215
Accounts payable	4,456	(4,373)
Taxes receivable/accrued	(5,998)	(38,106)
Other current liabilities	(2,115)	(3,781)
Net cash flows provided by operating activities	39,365	5,522
Investing Activities:		
Investments in property and plant	(49,634)	(32,792)

Proceeds from sales of investment securities		136,169		152,518
Purchases of investment securities		(136,763)		(154,951)
Other investing activities		489		136
Net cash flows used in investing activities		(49,739)		(35,089)
Financing Activities:				
Issuance of long-term debt		-		40,000
Retirement of rate reduction bonds		(10,178)		(9,540)
Increase in short-term debt		19,900		-
(Decrease)/increase in NU Money Pool borrowings		(4,000)		4,800
Capital contributions from NU parent		16,281		4,800
Cash dividends on common stock		(10,105)		(9,584)
Other financing activities		-		(681)
Net cash flows provided by financing activities		11,898		29,795
Net increase in cash		1,524		228
Cash - beginning of period		1,110		1,336
Cash - end of period	$	2,634	$	1,564

The accompanying notes are an integral part of these 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 the condensed consolidated financial statements and related notes included in this Quarterly Report on Form 10-Q, Northeast Utilities and subsidiaries combined first and second quarter 2008 Quarterly Reports on Form 10-Q and the Northeast Utilities and subsidiaries combined 2007 Annual Report on Form 10-K (NU 2007 Form 10-K) as filed with the Securities and Exchange Commission (SEC). References in this Form 10-Q to "NU" or "the company" are to Northeast Utilities combined with its subsidiaries, and the terms "we," "us" and "our" refer to NU. All per share amounts are reported on a fully diluted basis.

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

The discussion below also references our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation with Consolidated Edison, Inc. (Con Edison), which are also non-GAAP measures. We use these non-GAAP measures to more fully explain and compare the 2008 and 2007 results without including the impact of this settlement. Due to the nature and significance of the settlement charge, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to investors in analyzing historical and future performance. These measures should not be considered as alternatives to our reported net income or EPS determined in accordance with GAAP as indicators of our operating performance.

Reconciliations of the above non-GAAP measures to most directly comparable GAAP measures of consolidated fully diluted EPS and net income are included under "-Financial Condition and Business Analysis-Overview-Consolidated" and "-Financial Condition and Business Analysis-Future Outlook."

FINANCIAL CONDITION AND BUSINESS ANALYSIS

Executive Summary

The following items in this executive summary are explained in more detail in this quarterly report:

Results, Strategy and Outlook:

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We earned $72.7 million, or $0.47 per share, in the third quarter of 2008, compared with $50.2 million, or $0.32 per share, in the third quarter of 2007. The results in 2008 included regulated companies net income, after payment of preferred dividends, of $71.4 million, or $0.46 per share, competitive businesses or NU Enterprises, Inc. (NU Enterprises) net income of $4.6 million, or $0.03 per share, and NU parent and other companies net losses of $3.3 million, or $0.02 per share.

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We earned $188.9 million, or $1.21 per share, in the first nine months of 2008, compared with $173.8 million, or $1.12 per share, in the first nine months of 2007. The 2008 results included regulated companies net income, after payment of preferred dividends, of $218.5 million, or $1.40 per share, competitive businesses net income of $8.7 million or $0.05 per share, and NU parent and other companies net losses of $38.3 million, or $0.24 per share. The regulated companies net income includes earnings of $6.9 million, or $0.04 per share, primarily related to federal tax matters. The NU parent and other companies loss includes an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in the first nine months of 2008 were $218.7 million, or $1.40 per share.

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Earnings of the distribution segments of The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH) (including regulated generation), Western Massachusetts Electric Company (WMECO) and Yankee Gas Services Company (Yankee Gas) totaled $35.5 million in the third quarter of 2008 and $114.9 million in the first nine months of 2008, compared with $28.5 million in the third quarter of 2007 and $100.1 million in the first nine months of 2007.

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The transmission segments of CL&P, PSNH and WMECO earned $35.9 million in the third quarter of 2008 and $103.6 million in the first nine months of 2008, compared with $20 million in the third quarter of 2007 and $57 million in the first nine months of 2007.

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CL&P expects to have substantially completed its remaining major transmission projects in southwest Connecticut by the end of 2008. Refer to "Business Development and Capital Expenditures Regulated Companies Transmission Segment" in this Management s Discussion and Analysis for further discussion.

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We continue to project consolidated 2008 earnings of between $1.60 per share and $1.75 per share, including the effect of the litigation settlement with Con Edison, and between $1.80 per share and $1.95 per share excluding it. We project consolidated 2009 earnings of between $1.80 per share and $2.00 per share, including earnings at the distribution and generation segment of between $1.00 per share and $1.10 per share, earnings at the transmission segment of between $0.85 per share and $0.90 per share, earnings at the remaining competitive businesses of between $0.00 per share and $0.05 per share, and a loss of $0.05 per share at NU parent and other companies. We also continue to project an average compounded annual EPS growth rate of between 8 percent and 11 percent over 2007 EPS through 2013. Refer to "Future Outlook" in this Management s Discussion and Analysis for further discussion.

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We have an opportunity to make up to approximately $7 billion in capital investments from 2009 through 2013, which would enable us to increase our regulated transmission, distribution and generation rate base from approximately $6.5 billion up to $11.4 billion during this period. These estimates assume that our major projects, including the New England East-West Solutions (NEEWS) projects, are approved and completed according to our present schedule. Given the current market conditions, we continue to carefully examine each investment to assess customer benefits, shareholder benefits and the ability to raise necessary capital.

Legal, Regulatory and Other Items:

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On September 17, 2008, we and National Grid USA jointly submitted a filing with the Federal Energy Regulatory Commission (FERC) seeking incentives on NEEWS transmission upgrade components currently estimated to cost about $1.41 billion. The filing requests 100 percent construction work in progress (CWIP) cash recovery through rates, an incentive return on equity (ROE) of 13.14 percent and recovery of prudently incurred costs associated with project elements that may be cancelled for reasons outside of our control. We requested the FERC to rule on this filing within 60 days.

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As of October 2008, CL&P had entered into three contracts for differences (CfDs) with developers of peaking generation units approved by the Connecticut Department of Public Utility Control (DPUC). These units will have a total of 506 megawatts (MW) of peaking capacity. As directed by the DPUC, CL&P and The United Illuminating Company (UI) will share the net costs and benefits of the CfDs on a basis of 80 percent and 20 percent, respectively. CL&P s portion of the costs and benefits will be paid by or refunded to its customers.

Liquidity:

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Despite the volatility of the current financial markets, we believe our liquidity position is adequate to fund our operations and capital plans in the near term. Our companies have modest collateral or margin call risks. Our short-term funding needs are predictable, and we do not rely on a commercial paper program, but rather utilize the borrowing availability under our bank credit facilities. We also have only one series of bonds maturing before 2012 ($50 million in the second quarter of 2009). The credit outlooks for NU parent and our regulated companies are all stable. Capital expenditures projected for 2009 are less than 2008. We also expect a $100 million increase in internally-generated cash flows in 2009, which are projected to be approximately $550 million. We project our internally-generated cash flows to grow to $1 billion by 2013. Under our current projections, external financings totaling $550 million to $650 million are planned for mid-2009. Refer to "Liquidity-Impact of Financial Market Conditions" in this Management s Discussion and Analysis for further discussion.

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On October 7, 2008, we concluded our total 2008 financing plan of $760 million with the issuance by Yankee Gas of $100 million of first-mortgage bonds. Proceeds of the issuances will be used to repay debt, to fund ongoing capital investment programs and for general working capital purposes.

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As of November 5, 2008, we had approximately $86 million of externally invested cash. At this time, we also had approximately $285 million of borrowing availability on our revolving credit lines.

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Our cash capital expenditures totaled $951.8 million in the first nine months of 2008, compared with $750.2 million in the first nine months of 2007. The increase in our cash capital expenditures was primarily the result of higher transmission segment capital expenditures, particularly at CL&P. We project total capital expenditures of $1.3 billion in 2008.

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After giving effect to rate reduction bond payments included in financing activities, cash flows provided by operations in the first nine months of 2008 were $248 million, which represents an increase of $342 million from the same period in the prior year. This increase was primarily due to the absence in 2008 of approximately $400 million in tax payments related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. We project that we will generate approximately $450 million of cash flows from operations in 2008 after repayment of rate reduction bonds. Refer to "Liquidity-Consolidated" in this Management s Discussion and Analysis for further discussion.

Overview

Consolidated: We earned $72.7 million, or $0.47 per share, in the third quarter of 2008 and $188.9 million, or $1.21 per share, in the first nine months of 2008, compared with $50.2 million, or $0.32 per share, in the third quarter of 2007 and $173.8 million, or $1.12 per share, in the first nine months of 2007. Excluding an after-tax charge of $29.8 million, or $0.19 per share, associated with the settlement of litigation with Con Edison, our earnings in the first nine months of 2008 were $218.7 million, or $1.40 per share. A summary of our earnings by segment, which also reconciles the non-GAAP measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, to the most directly comparable GAAP measures of consolidated net income and fully diluted EPS, for the third quarter and the first nine months of 2008 and 2007, is as follows:

	For the Three Months Ended September 30,				**For the Nine Months Ended September 30,**			
	2008		**2007**		**2008**		**2007**	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income (GAAP)	$ 72.7	$ 0.47	$ 50.2	$ 0.32	$ 188.9	$ 1.21	$ 173.8	$ 1.12

Regulated companies	$ 71.4	$ 0.46	$ 48.5	$ 0.31	$ 218.5	$ 1.40	$ 157.1	$ 1.02
Competitive businesses	4.6	0.03	0.7	-	8.7	0.05	8.1	0.05
NU parent and other companies	(3.3)	(0.02)	1.0	0.01	(8.5)	(0.05)	8.6	0.05
Non-GAAP earnings	72.7	0.47	50.2	0.32	218.7	1.40	173.8	1.12
Con Edison litigation charge	-	-	-	-	(29.8)	(0.19)	-	-
Net Income (GAAP)	$ 72.7	$ 0.47	$ 50.2	$ 0.32	$ 188.9	$ 1.21	$ 173.8	$ 1.12

Regulated Companies: Our regulated companies, which consist of CL&P, PSNH, WMECO and Yankee Gas, segment their earnings between their electric transmission segment and their electric and gas distribution segments, with PSNH generation included with the electric distribution segment. A summary of regulated company earnings by segment for the third quarter and first nine months of 2008 and 2007 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**
CL&P Transmission*	$ 30.7	$ 16.9	$ 86.5	$ 47.3
PSNH Transmission	3.6	2.0	12.4	6.5
WMECO Transmission	1.6	1.1	4.7	3.2
Total Transmission	35.9	20.0	103.6	57.0
CL&P Distribution*	23.5	16.7	57.2	44.3
PSNH Distribution and Generation	10.7	11.0	32.3	31.7
WMECO Distribution	3.6	4.2	10.1	13.6
Yankee Gas	(2.3)	(3.4)	15.3	10.5
Total Distribution and Generation	35.5	28.5	114.9	100.1
Net Income - Regulated Companies	$ 71.4	$ 48.5	$ 218.5	$ 157.1

*After preferred dividends in all periods.

The higher third quarter and year-to-date 2008 transmission segment earnings reflect a higher level of investment in this segment as we continue to build out our transmission infrastructure to meet the region s reliability needs. CL&P s transmission earnings increased primarily due to CL&P s significant ongoing investment in projects in southwest Connecticut. Year-to-date 2008 transmission segment results also included first quarter earnings of approximately $3.5 million associated with an order on rehearing issued by the FERC on March 24, 2008 concerning the ROE allowed to owners of New England electric transmission facilities, including CL&P, PSNH and WMECO. Third quarter and year-to-date 2007 transmission segment results included a $2 million after-tax charge related to a FERC order concerning allowed transmission returns during a 15-month period that ended on September 3, 2006.

CL&P s third quarter 2008 distribution segment earnings were $6.8 million higher than the same period in 2007 primarily due to higher distribution revenues resulting from the distribution rate increase effective February 1, 2008, a settlement on federal tax matters, and a lower effective income tax rate, partially offset by a 2.7 percent reduction in sales and higher operating costs.

For the first nine months of 2008, CL&P s distribution segment earnings were $12.9 million higher than the same period in 2007 primarily due to higher distribution revenues, a settlement on federal tax matters, higher other revenues resulting from financial incentives under Connecticut s 2005 "Act Concerning Energy Independence" to promote distributed generation and demand side management, and a lower effective income tax rate. These items were partially offset by a 3.6 percent reduction in sales and higher operating costs. For the 12 months ended September 30, 2008, CL&P s distribution segment Regulatory ROE was 7.8 percent. We expect CL&P to achieve a distribution segment Regulatory ROE close to 8 percent in calendar year 2008.

PSNH s third quarter 2008 distribution and generation segment earnings were $0.3 million lower than the same period in 2007 primarily due to higher operating costs and a 2.2 percent decrease in sales, primarily offset by a settlement on federal tax matters and a lower effective income tax rate.

PSNH s distribution and generation segment earnings for the nine months ended September 30, 2008 were $0.6 million higher than the same period in 2007 as a result of distribution rate increases effective on July 1, 2007 and January 1, 2008, a pre-tax adjustment to its generation segment cost recovery mechanism of $1.9 million, higher generation segment rate base, and a settlement of federal tax matters, primarily offset by higher operating costs, the absence of a $4.5 million pre-tax benefit from the implementation of the retail transmission cost tracking mechanism in the second quarter of 2007, and a 1.1 percent decrease in sales. For the 12 months ended September 30, 2008, PSNH s combined distribution and generation segment Regulatory ROE was 8.8 percent. We expect PSNH to achieve a combined distribution and generation Regulatory ROE close to 9 percent in calendar year 2008.

WMECO s third quarter 2008 distribution segment earnings were $0.6 million lower than the same period in 2007 primarily due to higher operating costs, a $1.4 million pre-tax charge for potential refunds to customers from an assessment under the Massachusetts Department of Public Utilities' (DPU) service quality index criteria, and a 5.6 percent decline in sales. These items were partially offset by a settlement of federal tax matters and a $3 million annualized distribution rate increase that took effect on January 1, 2008.

WMECO s distribution segment earnings for the first nine months of 2008 were $3.5 million lower than the same period in 2007 primarily due to higher operating costs, a second quarter $1.6 million pre-tax charge related to a DPU ruling on WMECO s 2005 and 2006 transition charge reconciliations, the $1.4 million pre-tax charge described above, and lower sales, partially offset by a settlement of federal tax matters and a distribution rate increase effective January 1, 2008. For the 12 months ended September 30, 2008, WMECO s distribution segment Regulatory ROE was 7.9

percent. We expect WMECO to achieve a distribution Regulatory ROE close to 8 percent in calendar year 2008.

Yankee Gas lost $2.3 million in the third quarter of 2008 as compared to a loss of $3.4 million in the same period of 2007. The improvement in 2008 results was primarily due to a 13 percent increase in firm natural gas sales and lower income taxes, partially offset by higher operating costs. For the first nine months of 2008, Yankee Gas s earnings were $4.8 million higher than the same period in 2007, primarily due to a rate increase that took effect July 1, 2007, partially offset by a $5.8 million pre-tax charge recorded in the second quarter of 2008 for refunds of previous gas cost recoveries, and higher operating costs. Yankee Gas s year-to-date 2008 earnings were also impacted by weather as actual sales were unchanged from 2007, but on a weather normalized basis, 2008 sales were 2.9 percent higher. For the 12 months ended September 30, 2008, Yankee Gas s Regulatory ROE was 8.7 percent. We expect Yankee Gas to achieve a Regulatory ROE close to 8 percent in calendar year 2008.

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric kilowatt-hour (KWH) sales and Yankee Gas firm natural gas sales for the third quarter and first nine months of 2008 as compared to the same periods in 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	For the Three Months Ended September 30, 2008 Compared to 2007							
	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	Weather Normalized Percentage (Decrease)/ Increase	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc (Dec Inc
Residential	(3.3)%	(0.5)%	(2.6)%	0.9 %	(4.5)%	(2.6)%	(3.3)%	
Commercial	(1.4)%	0.2 %	(0.8)%	1.7 %	(4.6)%	(3.4)%	(1.6)%	
Industrial	(4.8)%	(3.4)%	(4.5)%	(2.0)%	(9.7)%	(9.0)%	(5.4)%	
Other	(4.2)%	(4.2)%	3.7 %	3.7 %	(7.1)%	(7.1)%	(3.9)%	
Total	(2.7)%	(0.6)%	(2.2)%	0.7 %	(5.6)%	(4.2)%	(2.9)%	

	For the Nine Months Ended September 30, 2008 Compared to 2007							
	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc Dec
Residential	(4.0)%	(2.4)%	(1.5)%	0.1 %	(3.6)%	(2.2)%	(3.5)%	
Commercial	(1.3)%	(0.7)%	0.8 %	1.9 %	(2.0)%	(1.5)%	(0.9)%	
Industrial	(8.9)%	(8.4)%	(4.6)%	(3.6)%	(8.0)%	(7.7)%	(7.6)%	
Other	(4.6)%	(4.6)%	1.9 %	1.9 %	(4.6)%	(4.6)%	(4.2)%	
Total	(3.6)%	(2.5)%	(1.1)%	0.1 %	(3.9)%	(3.1)%	(3.0)%	

A summary of our retail electric sales in gigawatt hours for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for the third quarter and first nine months of 2008 and 2007 is as follows:

For the Three Months Ended September 30,						
	Electric			Firm Natural Gas		
	2008	2007	Percentage Decrease	2008	2007	Percentage Increase
Residential	3,837	3,967	(3.3)%	1,024	947	8.1 %
Commercial	3,977	4,043	(1.6)%	1,313	1,182	11.1 %
Industrial	1,389	1,469	(5.4)%	2,848	2,461	15.8 %
Other	79	81	(3.9)%	-	-	0.0 %
Total	9,282	9,560	(2.9)%	5,185	4,590	13.0 %

For the Nine Months Ended September 30,						
	Electric			Firm Natural Gas		
	2008	2007	Percentage Decrease	2008	2007	Percentage (Decrease)/ Increase
Residential	10,947	11,339	(3.5)%	8,930	9,462	(5.6)%
Commercial	11,335	11,440	(0.9)%	8,890	9,086	(2.2)%
Industrial	3,914	4,235	(7.6)%	9,684	8,960	8.1 %
Other	246	257	(4.2)%	-	-	0.0 %
Total	26,442	27,271	(3.0)%	27,504	27,508	0.0 %

Third quarter and year-to-date 2008 electric sales were lower than the same periods in 2007. The third quarter and year-to-date 2008 weather normalized decreases of 0.7 percent and 2 percent reflect the fact that our customers are responding to the volatile costs of energy and to the economic conditions of our region and the nation. We believe customers will continue to respond to these factors and to the recent developments in the financial markets, and as a result, our weather normalized sales for the full year are projected to be 2.3 percent lower than 2007 sales, as compared to our original plan for a 0.4 percent increase.

A significant portion of electric revenues are tracked and reconciled to actual costs and a large portion of the distribution rate revenues (CL&P - 66 percent, PSNH - 48 percent, WMECO - 64 percent) are recovered through charges that are not dependent on overall sales volumes.

Firm natural gas sales for the third quarter of 2008 were higher than the same period in 2007 and, for the first nine months of 2008, were unchanged from the prior year. The 2008 results reflect warmer weather in the first quarter and an increase in industrial sales primarily due to customer-owned gas-fired distributed generation. Similar to our electric distribution companies, Yankee Gas recovers a portion of its distribution revenues through charges that are not dependent on usage. Yankee Gas would recover almost half of its

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revenues (45 percent) through non-usage charges if the DPUC approves its latest rate design proposal. The change in rate design would equate to approximately $175 thousand of distribution revenue for each 1 percent change in sales.

We continue to monitor our electric and firm natural gas sales closely and while we cannot determine whether the current trends will continue in the future, we have assumed a zero to 2 percent decline in weather normalized electric sales for 2009 and an increase in weather normalized firm natural gas sales for 2009 of approximately 1 percent. These assumptions are reflected in our earnings guidance for 2009.

Our uncollectibles expense is influenced by the economic conditions of our region and our write-offs as a percentage of revenues increased in 2008 for all of our electric distribution companies. For the first nine months of 2008, our total uncollectibles expense was approximately $10 million higher than the same period in 2007, but the impact on 2008 results was lower due to certain costs that are tracked such as write-offs attributable to hardship customers and the portion of uncollectibles expense allocated to the energy supply rate for the electric distribution companies. For the year, we believe the non-tracked portion of our uncollectibles expense will be approximately $6 million higher than we originally expected.

Competitive Businesses: NU Enterprises, which continues to manage to completion its remaining wholesale marketing contracts and energy services activities, earned $4.6 million in the third quarter of 2008 and $8.7 million in the first nine months of 2008, compared with $0.7 million in the third quarter of 2007 and $8.1 million in the first nine months of 2007. Year-to-date 2008 results include an after-tax reduction of earnings of $2.8 million associated with the implementation of Statement of Financial Accounting Standards (SFAS) No. 157, net of a $0.9 million benefit from partially reversing the SFAS No. 157 implementation charge as we served rather than exited Select Energy Inc. s (Select Energy) wholesale marketing contracts in 2008. Competitive business earnings for the third quarter and first nine months of 2008 included positive mark-to-market results of $3.6 million and $2.7 million, respectively, associated with the wholesale marketing contracts, as compared to negative mark-to-market results of $1.5 million and $2.8 million in the same periods of 2007, respectively.

NU Parent and Other Companies: NU parent and other companies had losses of $3.3 million in the third quarter of 2008 and $38.3 million in the first nine months of 2008, compared with earnings of $1 million in the third quarter of 2007 and $8.6 million in the first nine months of 2007. The loss in the first nine months of 2008 primarily relates to the payment by NU parent to Con Edison of $49.5 million in March 2008 as part of a comprehensive settlement of litigation initiated in 2001 over the proposed but unconsummated merger between the two companies. The decrease in earnings from the third quarter and first nine months of 2007 was also the result of reduced interest income for NU parent on a significantly lower level of cash in 2008. NU parent carried a high level of cash in the first quarter of 2007 resulting from the sale of our competitive generation businesses on November 1, 2006. Most of that cash was either invested in the regulated companies in 2007 to support those companies capital programs or used to pay taxes due in March 2007 on the competitive generation business sales. Additionally, NU parent interest expense increased in the third quarter of 2008 due to the replacement of $150 million of 3.3 percent senior notes that matured on June 1, 2008 with $250 million of 5.65 percent senior notes.

Future Outlook

Earnings Guidance: A summary of our projected 2008 and 2009 EPS by segment, which also reconciles consolidated fully diluted EPS to the non-GAAP measures of non-GAAP consolidated EPS and EPS by segment, is as follows:

	2008 EPS Range		2009 EPS Range	
(Approximate amounts)	**Low**	**High**	**Low**	**High**
Fully Diluted EPS (GAAP)	$ 1.60	$ 1.75	$ 1.80	$ 2.00
Regulated companies:				
Distribution and generation segment	$ 1.05	$ 1.10	$ 1.00	$ 1.10
Transmission segment	0.85	0.90	0.85	0.90
Total regulated companies	1.90	2.00	1.85	2.00
Competitive businesses	0.00	0.05	0.00	0.05
NU parent and other companies (excluding Con Edison litigation charge in 2008)	(0.10)	(0.10)	(0.05)	(0.05)
Non-GAAP EPS	1.80	1.95	1.80	2.00
Con Edison litigation charge	(0.19)	(0.19)	-	-
Fully Diluted EPS (GAAP)	$ 1.60	$ 1.75	$ 1.80	$ 2.00

We expect earnings to be at the high end of the range for the competitive businesses in 2008. The 2009 guidance is comparable to 2008, excluding the Con Edison charge, due to several negative factors, including the impact of the current economy on electric and gas sales and near-term pension expenses, and additional NU shares projected to be outstanding, offset by higher transmission earnings, scheduled rate relief at CL&P in February and expected rate relief at PSNH in July. We expect our electric distribution segment companies to earn a Regulatory ROE of approximately 7 percent to 8.5 percent for 2009, with PSNH generation and Yankee Gas earning approximately 9 percent to 10 percent.

Long-Term Growth Rate: We continue to project that we can achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent over 2007 earnings of $1.59 per share through 2013. This EPS growth rate assumes achieved Regulatory ROEs of approximately 12 percent for transmission and between 9 percent and 10 percent for generation and distribution investments. We believe this growth can be achieved if our capital program is successfully deployed according to our plans, distribution rate cases are approved to earn reasonable Regulatory ROEs, transmission policies by the FERC remain consistent to achieve projected transmission ROEs and we execute new transmission solutions.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, allowance for funds used during construction (AFUDC), and the capitalized portion of pension expense or income, totaled $946.6 million in the first nine months of 2008, compared with $842.1 million in the first nine months of 2007.

Regulated Companies:

We expect capital expenditures for the regulated companies to total $1.3 billion in 2008, which includes $22 million related to our corporate service company and other affiliated companies that support the regulated companies. We have an opportunity to make up to approximately $7 billion in regulated company capital investments from 2009 through 2013. Given the current market conditions, we continue to carefully examine each investment to assess customer benefits, shareholder benefits and the ability to raise necessary capital.

A summary of the projected capital expenditures for the regulated companies   transmission and the distribution and generation segments by company for 2008 and 2009 through 2013, including our corporate service companies   capital expenditures on behalf of regulated companies, is as follows (millions of dollars):

	Year						
	2008	2009	2010	2011	2012	2013	2009-2013 Totals
CL&P Transmission	$ 577	$ 119	$ 128	$ 267	$ 322	$ 160	$ 996
PSNH Transmission	85	69	177	400	273	154	1,073
WMECO Transmission	45	39	121	308	306	83	857
Other Transmission	-	-	20	95	205	205	525
Totals - Transmission	707	227	446	1,070	1,106	602	3,451
CL&P Distribution	292	280	352	338	309	311	1,590
PSNH Distribution	101	92	115	117	114	117	555
WMECO Distribution	35	28	38	33	33	34	166
Totals - Electric Distribution	428	400	505	488	456	462	2,311
PSNH Generation	69	123	199	144	83	41	590
Yankee Gas Distribution	62	71	90	92	74	77	404
Corporate service companies	22	71	34	21	13	12	151
Totals	$ 1,288	$ 892	$ 1,274	$ 1,815	$ 1,732	$ 1,194	$ 6,907

Actual capital expenditures could vary from the projected amounts for the companies and periods above. Based on those estimated expenditures, projected transmission and distribution and generation rate base at December 31 of each year are as follows (millions of dollars):

	Year					
	2008	2009	2010	2011	2012	2013
CL&P Transmission	$ 1,812	$ 2,024	$ 2,033	$ 2,224	$ 2,433	$ 2,454
PSNH Transmission	278	314	325	666	1,089	1,189
WMECO Transmission	99	125	218	488	729	876
Other Transmission	-	-	-	-	-	525
Totals - Transmission	2,189	2,463	2,576	3,378	4,251	5,044
CL&P Distribution	2,123	2,351	2,557	2,724	2,851	2,971
PSNH Distribution	699	774	865	954	1,042	1,095
WMECO Distribution	390	410	434	455	478	497
Totals - Electric Distribution	3,212	3,535	3,856	4,133	4,371	4,563
PSNH Generation	369	389	394	404	876	872
Yankee Gas Distribution	680	712	739	793	851	890
Totals	$ 6,450	$ 7,099	$ 7,565	$ 8,708	$ 10,349	$ 11,369

The projected capital expenditures and rate base amounts reflected above assume that PSNH s Clean Air Project will be completed by the end of 2012 at a cost of $457 million. They also assume that $1.49 billion in transmission projects associated with NEEWS will be completed before the end of 2013. Other Transmission capital expenditures and rate base amounts represent our potential investment in a transmission line to Canada.

Transmission Segment: Transmission segment capital expenditures increased by $84.5 million in the first nine months of 2008 as compared with 2007 primarily due to expenditures at CL&P, which continues its significant enhancement of its transmission system in southwest Connecticut. A summary of transmission segment capital expenditures by company in the first nine months of 2008 and 2007 is as follows (millions of dollars):

	For the Nine Months Ended September 30,	
	2008	2007
CL&P	$ 486.4	$ 429.9
PSNH	58.6	47.0
WMECO	27.9	12.3

HWP		1.6		0.8
Totals	$	574.5	$	490.0

CL&P has two major transmission projects currently under construction in southwest Connecticut. They are:

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The 69-mile, 345 kilovolt (KV)/115 KV transmission project from Middletown to Norwalk, Connecticut (Middletown-Norwalk) being constructed jointly with UI. CL&P's portion of this project is currently expected to cost approximately $950 million, $100 million lower than the earlier estimate of $1.05 billion due to a decrease in capitalized financing costs because of the earlier-than-expected in service date. Included in the above 2008 and 2009 projected capital expenditures are $330 million and $22 million, respectively, of the total cost of this project. The 45-mile overhead section of the project entered service on August 28, 2008. Extensive testing and commissioning of the 24-mile underground section is being conducted in the fourth quarter of 2008 and, absent any unanticipated events, the underground portion will be in service by early 2009. As of October 31, 2008, CL&P's portion of this project was 99 percent complete. As of September 30, 2008, CL&P had capitalized $885 million associated with this project and placed $429 million into service.

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The two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables). This project is estimated to cost approximately $239 million, which is $16 million higher than previous estimates due to increased construction costs to remove underground obstacles. As of October 31, 2008, this project was 98 percent complete and is expected to be completed ahead of schedule in November 2008. As of September 30, 2008, CL&P had capitalized $227 million associated with this project and placed $60 million into service.

In addition, the replacement 138 KV, 11-mile undersea electric transmission cable between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable) was placed into service on July 29, 2008. The project was temporarily taken out of service to bury the New York portion of the cable, which was completed in September 2008. This project is considered complete, subject to review and acceptance of as-built drawings by state and federal permit authorities. Based on final allocations, CL&P owns 51 percent of the project, with Long Island Power Authority owning the remainder. Due to this ownership re-allocation from 50.1

percent and higher than anticipated costs for the final cable burial, CL&P's portion of the project is anticipated to be approximately $78 million, which represents a $7 million increase over the previous estimate. As of September 30, 2008, CL&P had capitalized $71 million associated with this project and placed $67 million into service.

In addition to our current transmission construction in southwest Connecticut, we continue to plan for our next series of major transmission projects, NEEWS. That series of projects involves our construction of new overhead 345 KV lines in Massachusetts and Connecticut as well as associated substation work and 115 KV rebuilds. One of the projects will connect to a new transmission line that National Grid plans to build in Rhode Island. On September 24, 2008, the New England Independent System Operator (ISO-NE) issued its final technical approval of the NEEWS projects, which allows us to start the siting application process. We estimate that CL&P s and WMECO s total capital expenditures for these projects will be $1.49 billion through 2013.

The first of the NEEWS projects, the Greater Springfield Reliability Project, which involves a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. This project is expected to cost approximately $714 million if built according to our preferred route and configuration. CL&P filed its application to build the Connecticut portion of the Greater Springfield Reliability Project with the Connecticut Siting Council on October 20, 2008. WMECO filed its application to build its portion of the project with the Massachusetts Energy Facilities Siting Board on October 27, 2008. If approved as expected in 2010, we expect to commence construction in late 2010 and place the project in service by mid-2013.

Our second major NEEWS project is the Interstate Reliability Project, which is being designed and built in coordination with National Grid. CL&P's share of this project includes a 40-mile 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid is designing. We expect CL&P's share of this project to cost approximately $250 million. Municipal consultations began in September 2008, and CL&P plans to file siting applications with Connecticut regulators by the end of 2008 or early 2009 with construction beginning in 2010. We expect the project to be placed in service as early as late 2012.

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide us with another 345 KV connection to move power into southwest Connecticut, where approximately half of the state s electricity is consumed. The timing of this project would be six to twelve months behind the other two projects, and CL&P expects to initiate the siting process in 2009 with construction beginning in 2011. The project is expected to be placed in service in 2013 with a cost of approximately $315 million.

Included as part of NEEWS are approximately $210 million of reliability related expenditures, many of which may be incurred in advance of the three major projects.

During the siting approval process, state regulators may require changes in configuration to address local concerns that could increase construction costs. Our current design for NEEWS does not contemplate any underground 345 KV lines. Building 345 KV lines underground would increase total costs, and our estimate could be increased during the siting approval process.

Distribution Segment: A summary of distribution segment capital expenditures by company in the first nine months of 2008 and 2007 is as follows (millions of dollars):

	For the Nine Months Ended September 30,	
	2008	**2007**
CL&P	$ 202.4	$ 192.1
PSNH	65.3	66.1
WMECO	24.9	23.0
Totals - Electric Distribution	292.6	281.2
Yankee Gas	24.9	44.0
Other	0.4	0.1
Totals	$ 317.9	$ 325.3

On February 15, 2008, Yankee Gas and NRG Energy, Inc. (NRG) entered into a settlement agreement, which, among other things, enabled the recovery of approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that was abandoned. Year-to-date 2008 capital expenditures at Yankee Gas were reduced by this $17.5 million recovery, while the 2007 capital expenditures included $11 million spent on its $108 million LNG storage and production facility in Waterbury, Connecticut, which was placed in service in July 2007.

PSNH Generation: Capital expenditures for PSNH generation were $39.5 million for the nine months ended September 30, 2008, as compared to $18.6 million for the same period in the prior year. PSNH s Clean Air Project is expected to cost approximately $457 million, which will be recovered through its generation rates under New Hampshire law. PSNH expects to start preliminary site work for this project in November 2008, with completion of the project scheduled in 2012. New Hampshire law requires this project to be operational by July 2013. Capital expenditures at PSNH for the first nine months of 2008 include $11.4 million in costs related to this project.

Liquidity

Consolidated: We had $82.8 million of cash and cash equivalents on hand at September 30, 2008, compared with $15.1 million at December 31, 2007. This increase in cash balances was due to CL&P's temporary need for cash-on-hand of $62 million at September 30, 2008 to acquire certain of its Pollution Control Revenue Bonds (PCRBs) on October 1, 2008. As of November 5, 2008, we had approximately $86 million of externally invested cash. Refer to "Impact of Financial Market Conditions" below for further discussion.

We had positive operating cash flows of $248 million, after rate reduction bond payments included in financing activities, in the first nine months of 2008, compared with negative operating cash flows of $93.8 million, after rate reduction bond payments, in the first nine months of 2007. This increase was primarily due to the absence in 2008 of approximately $400 million in tax payments related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. After factoring these cash flow impacts, the decrease in operating cash flows in 2008 from 2007 was primarily due to a reduction in regulatory refunds and underrecoveries (net of income tax impacts) and a net reduction in other working capital items resulting primarily from a net $100 million increase in accounts receivable and unbilled revenue items, which also included investments in securitizable assets. Our consolidated regulatory refunds and underrecoveries decreased by $31 million from the six months ended June 30, 2008, primarily due to a $33 million deferral adjustment in the third quarter of 2008 for differences in transmission costs related to the Schedule 21 rates.

We project consolidated operating cash flows of approximately $450 million in 2008, after rate reduction bond payments of approximately $231 million. This projection includes an expected income tax net settlement of approximately $70 million in the fourth quarter and a reduction in income tax payments of $35 million during 2008 related to bonus depreciation.

A summary of the current credit ratings and outlooks by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch) for NU parent's and WMECO s senior unsecured debt and CL&P's and PSNH's first mortgage bonds is as follows:

	Moody's	S&P	Fitch

	Current	Outlook	Current	Outlook	Current	Outlook
NU Parent	Baa2	Stable	BBB-	Stable	BBB	Stable
CL&P	A3	Stable	BBB+	Stable	A-	Stable
PSNH	Baa1	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

On July 29, 2008, Moody's changed the outlook of Yankee Gas to stable from negative and affirmed the company's Baa2 corporate credit rating. On August 8, 2008, Fitch Ratings affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. In late October 2008, S&P affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. On November 5, 2008, S&P raised CL&P's unsecured debt rating to BBB from BBB- as a result of a comprehensive review of the unsecured ratings of United States investment grade utilities. S&P's ratings on CL&P's bonds and preferred stock were unaffected.

If NU parent s senior unsecured debt ratings were to be reduced to a sub-investment grade level by either Moody's or S&P, a number of Select Energy's supply contracts would require Select Energy to post additional collateral in the form of cash or letters of credit (LOCs). Select Energy would, under its remaining contracts, be required to provide cash or LOCs in the amount of $20.2 million to various unaffiliated counterparties and collateral or LOCs in the amount of $5.8 million to several independent system operators, in each case at September 30, 2008. If such a downgrade were to occur, NU parent would be able to provide that collateral. If unsecured debt ratings for CL&P or PSNH were to be reduced by either Moody's or S&P, a number of supply contracts would require CL&P and PSNH to post additional collateral in the form of cash or LOCs to various unaffiliated counterparties. If these ratings were to be reduced below investment grade, the amount of collateral required to be posted by CL&P and PSNH would be $2.3 million and $14 million, respectively, at September 30, 2008. If such a downgrade were to occur, CL&P and PSNH would be able to provide that collateral.

NU paid common dividends of $95.8 million in the first nine months of 2008, compared with $89.7 million in the first nine months of 2007. The increase reflects a 6.7 percent increase in NU's common dividend that took effect in the third quarter of 2007 and another 6.25 percent increase that took effect in the third quarter of 2008. On October 14, 2008, our Board of Trustees approved a quarterly common dividend of $0.2125 per share, payable on December 31, 2008 to shareholders of record as of December 1, 2008.

Beginning in 2009, we will target a dividend payout ratio of approximately 50 percent with a goal to continue our policy of increasing the dividend at a rate above industry average and to provide an attractive return to shareholders. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In the first nine months of 2008, CL&P, PSNH, WMECO and Yankee Gas paid $79.8 million, $27.3 million, $10.1 million, and $19 million, respectively, in common dividends to NU parent. In the first nine months of 2008, NU parent contributed $137.4 million of equity to CL&P, $46.6 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

NU s ability to pay common dividends is subject to approval by the Board of Trustees and our future earnings and cash flow requirements, and is not regulated under the Federal Power Act, but may be limited by certain state statutes, the leverage restrictions in its revolving credit agreement and the ability of its subsidiaries to pay common dividends. Unless a higher amount is approved by the FERC, the Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances, and PSNH is required to reserve an additional amount under its FERC hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

Cash capital expenditures included on the accompanying condensed consolidated statements of cash flows and described in the liquidity section of this Management's Discussion and Analysis do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portion of pension expense or income. Our cash capital expenditures totaled $951.8 million in the first nine months of 2008, compared with $750.2 million in the first nine months of 2007. Our cash capital expenditures in the first nine months of 2008 included $678.6 million by CL&P, $164.8 million by PSNH, $49.6 million by WMECO, $39.1 million by Yankee Gas and $19.7 million by other NU subsidiaries. The increase in our cash capital expenditures was primarily the result of higher transmission segment capital expenditures, particularly at CL&P.

NU Parent: NU parent has a credit line in a nominal aggregate amount of $500 million that expires on November 6, 2010. At September 30, 2008, NU parent had $67 million of LOCs issued for the benefit of certain subsidiaries and $182 million of borrowings outstanding under that facility. We have approximately $238 million of borrowing availability on this facility as of November 5, 2008.

Regulated Companies: The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million that expires on November 6, 2010. There were $45 million of long-term borrowings and $260.2 of short-term borrowings outstanding under that facility at September 30, 2008. We have approximately $47 million of borrowing availability on this facility as of November 5, 2008.

Impact of Financial Market Conditions: Despite the volatility of the current financial markets, we believe our liquidity position is adequate to fund our operations and capital plans in the near term. Due to our business model, our companies have modest collateral or margin call risks, as described further below. Our short-term funding needs are predictable, and we do not rely on a commercial paper program but rather utilize the borrowing availability under our bank credit facilities. The credit outlooks for NU parent and our regulated companies are all stable, with all their ratings and outlooks affirmed by S&P in late October 2008. Our dividend increases have been higher than the industry average growth rate over the past eight years; however, our dividend payout ratio has been less than 50 percent. Capital expenditures projected for 2009 are approximately 30 percent less than 2008 and debt maturities in 2009 are minimal, as described below. We also expect a $100 million increase in internally-generated cash flows in 2009, which are projected to be approximately $550 million. We project our internally-generated cash flows to grow to $1 billion by 2013. Under our current projections, the external financings described below are planned for mid-2009.

We have successfully completed our planned 2008 long-term debt financings, and we continue to have access to our two revolving credit facilities in a nominal aggregate amount of $900 million, both of which are due to expire in November 2010. The lenders under these facilities are: Bank of America, N.A.; Barclays Bank PLC; BNY Mellon, N.A.; Citigroup Inc.; HSBC Bank USA, N.A.; JPMorgan Chase Bank, N.A.; Lehman Brothers Commercial Bank (LBCB); Sumitomo Bank; Toronto Dominion (Texas) LLC; Union Bank of California, N.A.; Wachovia Bank, N.A.; and Wells Fargo Bank, N.A. Lehman Brothers Holdings Inc., the parent of LBCB, filed for Chapter 11 bankruptcy protection in September 2008. LBCB's original aggregate lending commitment under the facilities was $85 million, of which $30 million was assigned to Sumitomo Bank in late September, at which time LBCB had advanced approximately $23.5 million under the facilities. LBCB subsequently declined to fund the remainder of its commitment. As a result, when current loans from LBCB are repaid, we will be limited to an aggregate of $845 million of borrowing capacity under our credit facilities, which we believe will be sufficient to meet our near term liquidity needs. We have no further exposure to Lehman Brothers Holdings Inc. or any of its affiliates. As of September 30, 2008, we had borrowed an aggregate of approximately $487 million under the credit facilities, and $497 million as of November 5, 2008, including $23.5 million from LBCB. At the latter date, NU parent also had $62 million of LOCs issued under the NU parent credit facility for the benefit of certain subsidiaries.

We successfully accessed the credit markets in October 2008 when Yankee Gas issued in a private placement $100 million of 6.9 percent first mortgage bonds due in 2018. Yankee Gas plans to use the net proceeds to repay its borrowings under the regulated companies credit facility, to fund ongoing capital investment programs and for general working capital purposes.

PSNH has outstanding approximately $407 million of PCRBs, one series of which, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as the result of failed auctions due to concerns about the credit worthiness of the attached bond insurer. The interest rate on these PCRBs has reset by formula under the applicable documents every 35 days and has been between 0.4 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for a current interest rate of 0.4 percent. We are not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents. In addition, CL&P has one series of PCRBs in the aggregate principal amount of $62 million, which had a fixed interest rate for a five-year period that expired on September 30, 2008. CL&P chose to acquire these PCRBs on October 1, 2008 as a result of poor liquidity in the tax-exempt market using funds obtained from its credit facility and the NU Money Pool. These PCRBs, which mature in 2031, have not been retired, and CL&P expects to remarket them when conditions in the market improve.

We project that our capital expenditures will be $892 million in 2009, which is approximately 30 percent less than 2008 because we are between major transmission projects. We also project that cash flows from operations after rate reduction bond payments will increase by approximately $100 million from 2008 to 2009 due to our southwest Connecticut transmission projects being reflected fully in rates in 2009, lower refunds of the previous year s overcollections, a $20 million retail rate increase at CL&P, and the impact in 2008 of the Con Edison settlement. Also, only one series of our bonds matures prior to 2012, which is an aggregate principal amount issued by Yankee Gas of $50 million maturing in the second quarter of 2009. Due to these factors, we expect to require significantly less debt financing in 2009 than in 2008 (approximately $300 million to $350 million compared to $760 million in 2008). We also continue to assume a common share issuance of approximately $250 million to $300 million in 2009. The proceeds from these financings would be primarily used to fund our capital programs. We will monitor market conditions to determine the right timing and amount of 2009 financing requirements.

Our regulated standard offer type contracts do not require us to post collateral. The regulated companies continue to solicit bids on wholesale power contracts, the collateral terms of which are expected to be consistent with existing contracts. In other regulated contracts, the counterparties are generally exposed to us at this time, and these counterparties have posted the necessary collateral in the past when required. We do not expect these requirements to adversely affect our liquidity.

An affiliate of Constellation Energy Group, Inc. (Constellation), whose credit ratings were recently downgraded due to liquidity and other concerns, provides a significant amount of energy under CL&P s standard offer contracts. As of September 30, 2008, CL&P is not exposed to Constellation in terms of credit risk, and Constellation is performing on specific contracts that, in the event of Constellation s default, would require CL&P to provide standard offer type services directly to customers until a substitute supplier could be arranged. Any additional costs incurred by CL&P would be recoverable from customers. If Constellation were to default under existing contracts within the next 12 months, CL&P could be subject to the temporary posting of additional collateral up to between $35 million to $40 million with ISO-NE based on forward market prices as of September 30, 2008.

In addition, in 2005, Select Energy assigned a wholesale contract to Constellation. While Select Energy is not exposed to Constellation in terms of credit risk, Select Energy would be required to perform under the contract if Constellation defaults. We do not believe that this is likely, as Constellation is performing its obligations under the contract and the contract ends on December 31, 2008. Select Energy has no further significant exposure to Constellation.

Our collateral requirements for Select Energy s few remaining wholesale contracts are modest as we continue to wind down this business. Select Energy s largest remaining contract does not contain any collateral posting requirements. In addition, we have not experienced any significant performance difficulties with suppliers on Select Energy s remaining sourcing contracts. Select Energy is required to post collateral, primarily with the New York Mercantile Exchange (NYMEX), based on the market prices and status of its sourcing contracts. As of September 30, 2008, Select Energy had posted $11.6 million in related collateral, as compared to $18.9 million at December 31, 2007. Refer to "NU Enterprises Contracts Counterparty Credit Risk" in this Management s Discussion and Analysis for further discussion.

Our pension plan has historically been well funded, and we have not made a contribution to the plan since 1991. As of December 31, 2007, the fair value of our pension plan assets was approximately $2.5 billion, which exceeded the $2.3 billion projected benefit obligation by approximately $200 million. Due to current market conditions, the fair value of our pension plan assets is substantially lower now than it was at the end of 2007. At September 30, 2008, the fair value of our pension plan assets was approximately $2 billion. If the fair value of pension plan assets remains at or near this level at December 31, 2008, then we will be required to make a contribution to the plan of approximately $100 million to meet minimum funding requirements. The fair value of our pension plan assets continues to be subject to market volatility, and funding requirements could change accordingly. This contribution would not be required until the 2009 tax return is filed in the third quarter of 2010. The significant majority of our pension expense is recoverable from customers of our regulated companies.

Transmission Rate Matters and FERC Regulatory Issues

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

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Schedule 21 rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The Schedule 21 rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining two southwest Connecticut projects (Middletown-Norwalk and Glenbrook Cables). The Schedule 21 rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and Schedule 21 rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. In the third quarter of 2008, under the terms of Tariff No. 3, we deferred $33 million of differences, which resulted in the Schedule 21 rates being in a total underrecovery position of approximately $1 million as of September 30, 2008, which will fluctuate period to period.

FERC ROE Decision: On March 24, 2008, the FERC issued an order on rehearing increasing the base ROE on transmission projects for the transmission owners from the 10.2 percent allowed in the Initial ROE Order to 10.4 percent effective February 1, 2005 and reaffirmed its Initial ROE Order increasing the ROE by 74 basis points for the period beginning November 1, 2006 in recognition of higher bond yields. The rehearing order also modified the FERC's Initial ROE Order provision allowing 100 additional basis points for new transmission projects that are built as part of the ISO-NE Regional System Plan by limiting the 100 basis points adder solely to projects that are "completed and on line" by December 31, 2008. In order to receive incentives for projects completed after December 31, 2008, the rehearing order requires transmission owners to file with the FERC project-specific requests that meet the nexus requirements under FERC guidelines. In addition, while not an issue in this rehearing, the provision of the Initial ROE Order increasing the ROE by 50 additional basis points for New England transmission owners joining an RTO and giving the RTO operational control of the transmission owner s transmission facilities was left unchanged. In the first quarter of 2008, we recognized $3.5 million in transmission segment earnings related to this order, of which approximately $2.9 million related to the February 1, 2005 through December 31, 2007 time period. This order has been appealed to the D.C. Circuit Court of Appeals by various state regulators and municipal utilities. The court has set a schedule for the briefing to be concluded in the second quarter of 2009, with no date set for argument.

On May 16, 2008, CL&P filed an application with the FERC to receive ROE incentives for its Middletown-Norwalk project and to seek a waiver of the "completed and on line" date of December 31, 2008 to earn incentives. On July 17, 2008, the FERC granted a waiver of the December 31, 2008 "completed and on line" date for a 100 basis point ROE adder and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project and ordered us to file a compliance filing with details regarding the advanced technology. The 50 basis point adder will be limited to 46 basis points based on the present overall ROE limit established by the FERC, resulting in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent. The cost of the underground portion is estimated to be slightly less than half of CL&P's overall cost of approximately $1 billion. Once all advanced technology equipment is in service, the technology adder will increase our consolidated annual earnings beginning in 2009 by approximately $1 million.

On August 18, 2008, CL&P made a compliance filing with the FERC detailing the costs associated with the underground cables and supporting facilities of the Middletown-Norwalk project, which qualified as advanced technology. On that same day, several parties filed a request for rehearing on the total 146 basis point incentive that the FERC granted. In addition, on September 8, 2008, the DPUC filed a motion to reject and protest our compliance filing, stating we did not provide sufficient information. There is no specific deadline for the FERC to respond to this motion, but our response to the protest has been filed at the FERC.

NEEWS Incentives: On September 17, 2008, we and National Grid USA jointly submitted a filing with the FERC seeking financial incentives and rate amendments for the NEEWS projects. We have asked that the FERC rule on these requests within 60 days. The requested incentives include:

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A ROE of 13.14 percent, representing an incentive of 150 basis points, which is aligned with recent FERC ROE decisions for other large transmission projects;

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100 percent inclusion of prudently incurred CWIP in rate base; and

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Full recovery of prudently incurred costs if NEEWS, or any portion thereof, is cancelled as a result of factors beyond NU's or National Grid's control.

Our share of NEEWS is estimated to cost $1.49 billion, and we are seeking incentives on transmission upgrades associated with approximately $1.41 billion of these costs. The FERC received third party comments objecting to our incentive filing and has until November 17, 2008 to rule on our filing.

Legislative Matters

Environmental Legislation: The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten northeastern and mid-Atlantic states, including Connecticut, New Hampshire and Massachusetts, to develop a regional program for stabilizing and reducing carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating plants. RGGI proposes to stabilize CO_2 emissions at 2009 levels and reduce them by 10 percent from these levels by 2018. RGGI is composed of individual CO_2 budget trading programs in each of the participating states. Each participating state s CO_2 budget trading program establishes its respective share of the regional cap, and each state will issue CO_2 allowances in a number equivalent to its portion of the regional cap. Each CO_2 allowance represents a permit to emit one ton of CO_2 in a specific year. The RGGI states will distribute CO_2 allowances primarily through regional auctions. Regulated power generators are able to purchase CO_2 allowances issued by any of the participating states to demonstrate compliance with the RGGI program of the state governing their generating plants. Taken together, the individual participating state programs will function as a single regional compliance market for carbon emissions.

Connecticut adopted regulations in July 2008 which established an auction clearing price threshold of $5 per CO_2 allowance, above which all auction proceeds will be rebated to customers. For proceeds up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed by the state s utilities in conjunction with the Energy Conservation Management Board. Seventy-five percent of the RGGI auction proceeds directed to conservation and load management programs will be allocated to CL&P s programs. Because CL&P does not own any generating assets, it is not required to acquire CO_2 allowances.

Massachusetts law did not set an auction clearing price threshold for RGGI auctions. The law requires 80 percent of RGGI auction proceeds to be allocated to utility energy efficiency and demand response programs. Because WMECO does not own any generation assets, it is not required to acquire any CO_2 allowances either.

New Hampshire law sets an auction clearing price threshold of $6 per CO_2 allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO_2 per year after taking into effect the operation of PSNH s Northern Woods wood-burning generating plant, which, under the RGGI formula, decreased PSNH s responsibility for reducing fossil-fired CO_2 emissions by approximately 425,000 tons per year, or almost ten percent**.** New Hampshire legislation provides up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled generating plants during the 2009-2011 compliance period. These banked CO_2 allowances will comprise approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants to comply with RGGI. PSNH expects to satisfy its remaining RGGI requirements from 2009 to 2011 by purchasing CO_2 allowances at auction or in the secondary market.

The first regional auction of RGGI CO_2 allowances took place on September 25, 2008. At the auction, CO2 allowances were sold at the clearing price of $3.07 per CO_2 allowance. The next regional auction is scheduled for December 2008.

Massachusetts:

Corporate Excise Tax: On July 3, 2008, Massachusetts amended its corporate excise tax provisions, which are effective for tax years beginning on or after January 1, 2009. Companies must account for the impact of income tax law changes in the period that includes the enactment date of the law change. As a result, WMECO recorded an estimate of the impact of the new legislation as a $4.7 million decrease to deferred tax liabilities and a decrease to regulatory assets on its condensed consolidated balance sheet as of September 30, 2008. The company will continue to monitor this legislation as Massachusetts provides further details.

Regulatory Developments and Rate Matters

Regulated Distribution Companies: We are currently evaluating the rate case strategies of our distribution companies. Based on each company s earnings, cost trends and sales trends in 2008, it is probable that PSNH will file a distribution rate case in mid-2009 seeking temporary rates effective July 2009, and it is possible that CL&P will file a distribution rate case in mid-2009 to be effective in January 2010. In response to the July 2008 rate decoupling decision in Massachusetts, WMECO notified the DPU that it intends to file a distribution rate case with full decoupling in mid-2010 to be effective in January 2011. We have no near-term plans to file a distribution rate case for Yankee Gas.

Connecticut:

Peaking Generation Contracts: As of October 2008, CL&P had entered into three CfDs with developers of peaking generation units approved by the DPUC. These units will have a total of 506 MW of peaking capacity. As directed by the DPUC, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P s portion of the costs and benefits will be paid by or refunded to CL&P customers.

FMCC Filing: In September 2008, the DPUC approved CL&P s semi-annual federally mandated congestion charges (FMCC) filing, which reconciled the full year period January 1 through December 31, 2007, and which identified a total overrecovery of $105.4 million at December 31, 2007. This overrecovery is being fully returned to customers in 2008 through credits included in 2008 rates that were determined in separate rate proceedings. On August 5, 2008, CL&P filed with the DPUC its semi-annual reconciliation to document actual FMCC revenues and charges (including Energy Independence Act charges), and generation service charge (GSC) revenues and charges for the period January 1, 2008 through June 30, 2008. This filing identified a net overrecovery totaling approximately $30.9 million including the remaining unamortized overrecovery from 2007. A draft decision is scheduled for November 14, 2008, and a final decision is scheduled for November 26, 2008.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under Last Resort Service (LRS) rates. Effective July 1, 2008, the DPUC approved an increase to CL&P's total average SS and LRS rates of approximately 4.9 percent and 33.2 percent, respectively. The new LRS rate remained in effect until September 30, 2008, after which it declined by approximately 10 percent to a new rate that will remain in effect until December 31, 2008, while the new SS rate will remain in effect until December 31, 2008. The energy supply portion of the total average SS rate increased from 11.762 cents per KWH to 11.852 cents per KWH. The energy supply portion of the total average LRS rate increased from 10.466 cents per KWH to 14.559 cents per KWH then declined to 12.667 cents per KWH. CL&P is fully and timely recovering the costs of its SS and LRS services.

Customer Service Docket: On August 6, 2008, the DPUC issued a final decision in a docket investigating CL&P billing errors involving approximately 2,000 customers on time of use rates. The final decision found that CL&P s actions and communications both internally and externally after it found that the bills were not being accurately calculated were imprudent. The decision requires CL&P to investigate and report what steps CL&P can take in the future to identify and respond quicker to billing system errors. The decision also disallowed recovery from customers of the incremental costs associated either directly or indirectly with the billing errors, which are not material and have been expensed as incurred. CL&P filed a compliance filing on September 30, 2008 outlining the costs associated with the billing errors as directed by the DPUC.

2008 Conservation and Load Management Plan: On September 24, 2008, the DPUC issued its final decision authorizing CL&P to spend an additional $10 million to fund Conservation and Load Management programs in 2008. The $10 million is to be taken from allowed funding for the 2009 Conservation and Load Management programs. The decision also found that CL&P did not act in a prudent manner in communicating the suspension of certain programs to the DPUC. As a result, the decision disallowed CL&P to earn a performance incentive on the $10 million authorized to restore the suspended programs and orders that any earned return on the $10 million be based on CL&P's short-term debt rate instead of its overall rate of return. We do not expect any material impact to our financial statements from this decision.

2008 Management Audit: On August 18, 2008, a consulting firm hired by the DPUC began an on-site management audit of CL&P, which is required to be conducted every six years by statute and requires a diagnostic review of all functions of the company. The audit will be ongoing through the remainder of 2008, and a draft report is expected to be provided to CL&P for comment in mid-January 2009. A final audit report is scheduled to be filed with the DPUC in late January 2009. We do not expect any impacts to our financial statements from results of this audit.

C2 Prudence Audit: Pursuant to the decision in CL&P's 2007 rate case, the DPUC has hired a consulting firm to perform a prudency audit of certain costs incurred in the implementation of a new customer service system (C2) at CL&P. The audit will begin in December 2008, with a final audit report to the DPUC due March 31, 2009. The DPUC has stated its intentions to open a new proceeding to review the prudence of the C2 costs. At this time we do not know the scope of the audit or the proceeding. However, we do not expect a material impact to our financial statements as we believe all costs were prudently incurred.

New Hampshire:

Merrimack Clean Air Project: In 2006, the New Hampshire legislature enacted legislation requiring PSNH to reduce the mercury emissions from its coal-fired Merrimack Station in Bow, New Hampshire by at least 80 percent through the installation of wet scrubber technology no later than July 1, 2013. Following an August 2008 announcement by PSNH that the cost of this installation would be increasing from $250 million to $457 million, the New Hampshire Public Utilities Commission (NHPUC) opened an inquiry to determine its authority to find whether the project is in the public interest before PSNH began construction. On September 19, 2008, the NHPUC ruled that it lacks authority in this matter, stating the New Hampshire legislature made a determination on the public s interest in 2006 when it required PSNH to install the scrubber technology. In its ruling, the NHPUC said that it retains jurisdiction over prudence of construction costs. In October 2008, several parties filed motions with the NHPUC requesting a reconsideration of its ruling. On October 27, 2008, the NHPUC suspended its September 19 decision pending further consideration of the issues raised in the motions. The NHPUC is expected to make a definitive decision regarding the rehearing motions in November 2008. PSNH expects to begin preliminary site work for this project in November 2008.

Major Storm Reserve: On June 27, 2008, the NHPUC issued an order in which the NHPUC accepted PSNH's proposal to increase its distribution rates by approximately $3 million for a two-year period effective July 1, 2008 to eliminate a negative balance in the major storm reserve and restore the intended reserve level of $1 million. As part of its review of the PSNH proposal, the NHPUC conducted an audit of major storm costs included in the reserve. On October 2, 2008, the NHPUC staff issued its final audit report, which had no impact on PSNH s earnings.

ES and SCRC Rates: On June 27, 2008, the NHPUC approved default energy service (ES) and stranded cost recovery charge (SCRC) rates of 9.57 cents and 0.65 cents per KWH, respectively, which are effective July 1, 2008 through December 31, 2008. On September 12, 2008, PSNH filed petitions with the NHPUC requesting increases in both its ES and SCRC rates on a preliminary basis for the period January 1, 2009 through December 31, 2009. Consistent with previous rate filings, PSNH is requesting that the NHPUC review and approve the underlying data in these filings, not a specific ES or SCRC rate. PSNH expects to petition the NHPUC in early December 2008 for specific 2009 ES and SCRC rates.

Massachusetts:

Basic Service Rates: Effective October 1, 2008, the rates for WMECO's medium and large commercial and industrial basic service customers decreased due to the decline in the cost of energy, which was reflected in its most recent basic service solicitations. Basic service rates for medium and large commercial and industrial customers decreased from 14.6 cents per KWH to 11.1 cents per KWH.

Service Quality Performance Assessment: As part of the December 2006 rate case settlement agreement approved by the DPU, WMECO became subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred are paid to customers through a method approved by the DPU. WMECO will likely be required to pay an assessment charge for its year-to-date reliability performance against the metrics established for 2008, primarily as a result of significant storm activity. WMECO has performed at target for other non-storm related reliability metrics. WMECO will file its 2008 SQ results and assessment calculation with the DPU in March 2009. In the third quarter of 2008, WMECO recorded an estimated pre-tax charge and a regulatory liability of approximately $1.4 million for this assessment. This amount is subject to adjustment in the fourth quarter of 2008 based on actual results.

Transfer of Transmission Assets: On November 5, 2008, our wholly owned subsidiaries, HWP, HP&E and WMECO, filed a joint application with the FERC requesting approval to transfer approximately $3.5 million in transmission related assets of HWP and HP&E to WMECO. We expect a decision by the FERC and closing of the transaction by the end of 2008.

Contingent Matters:

The items summarized below contain contingencies that may have an impact on our net income, financial position or cash flows. See Note 5A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the condensed consolidated financial statements for further information regarding these matters.

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CTA and SBC Reconciliation: On March 31, 2008, CL&P filed with the DPUC its 2007 Competitive Transition Assessment (CTA) and System Benefits Charge (SBC) reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying condensed consolidated balance sheets. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying condensed consolidated balance sheets. We expect a decision from the DPUC on this docket by the end of 2008 and do not expect the outcome to have a material adverse effect on CL&P's net income, financial position or cash flows.

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Procurement Fee Rate Proceedings: CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings, although CL&P would file for recognition of after-tax amounts of $3.3 million for 2006 and $3.6 million for 2005 if and when its methodology is approved.

CL&P has recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. If the DPUC does not allow recovery of $5.8 million for procurement fees in its final decision, then CL&P would record a loss and establish an obligation to refund this amount to its customers. A date for the new draft decision in this docket has not yet been determined by the DPUC. We believe that final regulatory approval of the $5.8 million pre-tax amount is probable.

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ES and SCRC Reconciliation: On May 1, 2008, PSNH filed its 2007 ES/SCRC reconciliation with the NHPUC. During 2007, ES and SCRC revenues exceeded ES and SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a regulatory liability to be refunded to customers. The NHPUC is currently reviewing this filing, which includes a prudence review of PSNH's generation operations. Testimony filed on October 24, 2008 by the NHPUC's consultant contained no material adverse findings. Hearings are scheduled before the NHPUC in November 2008. We do not expect the outcome of the NHPUC's review of this filing to have a material adverse impact on PSNH's net income, financial position or cash flows.

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Transition Cost Reconciliation: On July 18, 2008, WMECO filed its 2007 transition cost (TC) reconciliation with the DPU, which compared TC revenue and revenue requirements. For the twelve months ended December 31, 2007, total TC revenues along with carrying charges exceeded TC revenue requirements by $2.6 million, which has been recorded as a regulatory liability on the accompanying condensed consolidated balance sheets. On September 19, 2008, the DPU issued an order of notice for this proceeding, scheduling a public hearing and procedural conference on November 20, 2008. We do not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.

NU Enterprises Divestitures

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

Wholesale Marketing: During 2008 Select Energy continued to manage its remaining PJM power pool wholesale sales contract and its related supply contracts, which expired on May 31, 2008, and its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, and related supply contracts, that expires in 2013. These contracts are derivatives that have been marked to market through earnings. In addition to the NYMPA-related contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase the output of a certain generating facility in New England through 2012. As a non-derivative contract, the fair value of the contract has not been reflected on the balance sheet, and the contract has not been marked to market. Based on the current estimated value of this non-derivative contract, when combined with the fair value of the derivative contracts in the NYMPA portfolio and cash collateral balances at September 30, 2008, we believe, under present conditions, that the estimated total net cash cost at September 30, 2008 to exit the remaining wholesale contracts if served out or settled at the same time is approximately break-even.

Energy Services: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. Certain other businesses were wound down in 2007; however, we continue to own and actively manage one energy services business, E.S. Boulos Company.

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, we provided various guarantees and indemnifications to the purchasers of those businesses. See Note 5D, "Commitments and Contingencies - Guarantees and Indemnifications," to the condensed consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: On January 1, 2008, we implemented SFAS No. 157. For further information on SFAS No. 157, see Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the condensed consolidated financial statements, and the "Critical Accounting Policies and Estimates Update" section of this Management s Discussion and Analysis.

At September 30, 2008 and December 31, 2007, the fair value of NU Enterprises' wholesale derivative assets and derivative liabilities (through its subsidiary Select Energy), which are subject to mark-to-market accounting, are as follows:

(Millions of Dollars)	**September 30, 2008**		**December 31, 2007**	
Current wholesale derivative assets	$	4.1	$	36.2
Long-term wholesale derivative assets		3.1		7.2
Current wholesale derivative liabilities		(18.5)		(64.9)
Long-term wholesale derivative liabilities		(57.3)		(72.5)
Portfolio position	$	(68.6)	$	(94.0)

Numerous factors could either positively or negatively affect the realization of the wholesale derivative net fair value amounts in cash. These factors include the volatility of commodity prices until the derivative contracts are exited or expire, differences between expected and actual volumes, the performance of counterparties, and other factors.

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

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts at September 30, 2008 and December 31, 2007. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as prior contract settlements with third parties and bilateral contract prices in illiquid periods. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based on a model. The model utilizes natural gas prices and a conversion factor to electricity for off-peak periods in 2012 and all periods for 2013. Broker quotes for electricity, at locations for which Select Energy has entered into transactions, are generally available through 2011 for on-peak and off-peak periods and through 2012 for on-peak periods.

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

The tables below disaggregate the estimated fair value of the wholesale derivative contracts. Valuations of individual contracts are broken into their component parts based upon prices actively quoted, prices provided by external sources and model-based amounts. Under SFAS No. 157, contracts are classified in their entirety according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, these contracts are classified as Level 3 under SFAS No. 157. At September 30, 2008 and December 31, 2007, the sources of the fair value of wholesale derivative contracts are included in the following tables:

	Fair Value of Wholesale Contracts at September 30, 2008			
(Millions of Dollars) **Sources of Fair Value**	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Maturity in Excess of Four Years**	**Total Fair Value**
Prices actively quoted	$ (5.1)	$ 2.0	$ 0.3	$ (2.8)
Prices provided by external sources	(8.6)	(31.6)	(3.8)	(44.0)
Model-based [(1)]	(0.7)	(6.3)	(14.8)	(21.8)
Totals	$ (14.4)	$ (35.9)	$ (18.3)	$ (68.6)

	Fair Value of Wholesale Contracts at December 31, 2007			
(Millions of Dollars) **Sources of Fair Value**	**Maturity Less than One Year**	**Maturity of One to Four Years**	**Maturity in Excess of Four Years**	**Total Fair Value**
Prices actively quoted	$ (4.7)	$ (0.2)	$ 1.4	$ (3.5)
Prices provided by external sources	(24.0)	(38.8)	(13.4)	(76.2)
Model-based	-	4.3	(18.6)	(14.3)
Totals	$ (28.7)	$ (34.7)	$ (30.6)	$ (94.0)

(1) The model-based amounts include the effects of implementing SFAS No. 157.

For the three and nine months ended September 30, 2008, the changes in fair value of these contracts are included in the following table:

(Millions of Dollars)	For the Three Months Ended September 30, 2008 Total Portfolio Fair Value	For the Nine Months Ended September 30, 2008 Total Portfolio Fair Value
Fair value of wholesale contracts outstanding at the beginning of the period	$ (74.6)	$ (94.0)
Pre-tax effects of implementing SFAS No. 157 ($3.7 million after-tax) [1]	-	(6.1)
Contracts realized or otherwise settled during the period [2]	-	27.0
Period change in unrealized gains included in earnings	6.0	4.5
Fair value of wholesale contracts outstanding at the end of the period	$ (68.6)	$ (68.6)

(1)

Pre-tax effect recorded in fuel, purchased and net interchange power on the condensed consolidated statement of income.

(2)

Amount includes purchases, issuances and settlements of $0.7 million and $21.3 million for the three and nine months ended September 30, 2008, respectively, and realized intra-month losses of $0.7 million and gains of $5.7 million for the three and nine months ended September 30, 2008, respectively.

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

Counterparty Credit Risk: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to our continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. At September 30, 2008, approximately 95 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, approximately four percent was rated BBB- or better and approximately one percent was collateralized. The bulk of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we have assessed as creditworthy. To date, this counterparty has met all of its contractual obligations.

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 statements. Our management communicates to and discusses with our Audit Committee of the Board of Trustees all critical accounting policies and estimates. All of these critical accounting policies and estimates were reported in the 2007 Form 10-K. There have been no material changes with regard to these critical accounting policies and estimates, except as follows:

Accounting for Environmental Reserves: Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to environmental reserves could have a significant effect on earnings. Our approach estimates these liabilities based on the most likely action plan from a variety of available options, ranging from no action to establishing institutional controls, full site remediation and long-term monitoring. The estimates associated with each possible action plan are based on findings through various phases of site assessments.

These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations and several cost estimates from third-party engineering and remediation contractors. These estimates also take into consideration prior experience in remediating contaminated sites and data released by the United States Environmental Protection Agency and other organizations. These estimates are subjective in nature partly because there are usually several different remediation options from which to choose when working on a specific site. These estimates are subject to revision in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations. The amounts recorded as environmental liabilities on the condensed consolidated balance sheets represent our best estimate of the liability for environmental costs based on current site information from site assessments and remediation estimates. These liabilities are recorded on an undiscounted basis.

Holyoke Water Power Company (HWP) is a subsidiary of NU that owns a minimal amount of transmission property and has limited operating activities. HWP continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in the first nine months of 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of September 30, 2008. The cumulative expense recorded to this reserve through September 30, 2008 was approximately $15.9 million, of which $13.3 million had been spent, leaving approximately $2.6 million in the reserve as of September 30, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, who share responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed plans for additional investigations in conformity with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, we believe that the $2.6 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $2.6 million to $3.3 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2009.

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

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

Presentation: In accordance with GAAP, our consolidated financial statements include all subsidiaries over which control is maintained and would include any variable interest entities (VIE) for which we are the primary beneficiary as defined in Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46(R), "Consolidation of

Variable Interest Entities." Determining whether we are the primary beneficiary of a VIE is complex and subjective, and requires our judgment. There are a variety of facts and circumstances and a number of variables taken into consideration to determine whether we are considered the primary beneficiary of a VIE. A change in facts and circumstances or a change in accounting guidance could require us to reconsider whether or not we are the primary beneficiary of the VIE.

The Energy Independence Act required the DPUC to consider the impact on distribution companies of entering into long-term contracts for capacity and contracts to purchase renewable energy products from new generating plants. We reviewed each contract to determine the appropriate accounting treatment based on the terms of the contracts. In April 2007, CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. In May 2008, CL&P and UI entered into six additional long-term agreements with proposed renewable energy plants. In July 2008, UI signed an additional contract. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these contracts with 80 percent to CL&P and 20 percent to UI. We evaluated whether entering into these contracts would require consolidation and determined that consolidation of the projects would not be required. The review of these contracts required significant management judgment.

In 2007, CL&P entered into two CfDs associated with the capacity of two generating projects to be built or modified, and UI entered into two capacity-related CfDs, one with a generating project to be built and one with a new demand response project. The contracts, referred to as Capacity CfDs, obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four Capacity CfDs with 80 percent to CL&P and 20 percent to UI. We determined that these contracts are derivatives and do not require consolidation.

The Energy Efficiency Act required electric distribution companies, including CL&P, and allowed others to file proposals with the DPUC to build cost-of-service peaking generation facilities. As of October 2008, CL&P has entered into three CfDs with developers of peaking generation units approved by the DPUC (Peaker CfDs). As directed by the DPUC, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker

CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. Amounts paid or received under the Peaker CfDs will be recoverable from or refunded to customers. CL&P signed contracts with two projects in the third quarter of 2008 and one project in October 2008. We evaluated whether these contracts are variable interests in VIEs that would require CL&P to consolidate the projects. CL&P has determined that none of these projects requires consolidation as of September 30, 2008. In future periods, one of the three projects may require consolidation if it becomes a VIE. Consolidation of that project would not impact CL&P's net income, but could add approximately $140 million of plant, $85 million of nonrecourse debt and $55 million of minority interest to CL&P s balance sheet by the time the plant is placed in service (scheduled for June 2012). Any demonstrated increases in financing or other costs that might result from consolidation of the project would be recoverable from CL&P's customers.

The FASB is in the process of reinterpreting the consolidation requirements of FIN 46(R). If the proposed guidance were finalized in its current form, it would eliminate the requirement for consolidation when we do not have the power to direct matters that significantly impact the VIE's activities. CL&P would not be required to consolidate the peaker project if and when the new guidance becomes effective. The FASB reinterpretation of FIN 46(R), as drafted, would become effective on January 1, 2010. Changes in facts and circumstances and changes in accounting guidance resulting in reevaluation of the accounting treatment of these contracts could have a significant impact on the accompanying consolidated financial statements.

Fair Value Measurements: We adopted SFAS No. 157 as of January 1, 2008. SFAS No. 157 defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). It establishes a framework for measuring fair value, using a three level hierarchy based upon the observability of inputs to the valuations. See Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 3, "Fair Value Measurements," to the accompanying condensed consolidated financial statements for further information.

As of January 1, 2008, we applied SFAS No. 157 to our regulated and unregulated companies derivative contracts that are recorded at fair value and to the marketable securities held in NU s Rabbi Trust and WMECO s prior spent nuclear fuel trust. SFAS No. 157 also applies to investment valuations for our pension and other postretirement benefit plans beginning as of December 31, 2008 and, beginning in 2009, to nonrecurring fair value measurements of non-financial assets and liabilities, such as goodwill and asset retirement obligations. Implementing SFAS No. 157 for our marketable securities expanded our financial statement disclosures, but did not affect the recorded fair value of investments.

In the first nine months of 2008, we recorded an after-tax reduction of earnings of $2.8 million as a result of applying SFAS No. 157 to derivative liabilities for Select Energy s remaining wholesale marketing contracts, net of a $0.9 million benefit from partially reversing the implementation charge as we served rather than exited these contracts during the period.

As a result of implementing SFAS No. 157, we also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers, and an offsetting regulatory asset or liability was recorded to reflect these changes. Implementing SFAS No. 157 resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets, of approximately $590 million and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million. The increase to CL&P's derivative liabilities primarily resulted from an increase in the negative fair value of a CfD with a generating plant to be built to reflect the estimated cost to exit this contract, reflecting an increase in the probability that the plant will be built and the recognition of a loss at the inception of the contract of approximately $100 million that was deferred under previous accounting guidance.

If we do not exit but rather serve out our derivative liability contracts, we will not make payments for some portion of the negative fair value recorded for the contracts. Likewise, we could receive more cash for derivative assets than the fair value recorded.

We use quoted market prices when available to determine fair values of financial instruments and classify those valuations as Level 1 within the fair value hierarchy.

If quoted market prices are not available, fair value is determined using quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments that are not active and model-derived valuations in which all significant inputs are observable. These valuations are classified as Level 2 within the fair value hierarchy.

Many of our derivative contracts that are recorded at fair value are classified as Level 3 within the hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit risk. Contracts valued using models 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 as Level 3 even though there may be some significant inputs that are readily observable.

Changes in fair value of the remaining wholesale marketing contracts of our unregulated businesses are recorded in fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income. For the three and nine months ended September 30, 2008, there were net unrealized gains of $3.6 million and $2.7 million, respectively, related to the valuation of these contracts. For the three and nine months ended September 30, 2008, there were net realized losses of $0.4 million and gains of $3.4 million, respectively, related to the valuation of these contracts. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts.

Changes in fair value of the regulated company derivative contracts are recorded as regulatory assets or liabilities, as we expect to recover these costs in rates. These valuations are sensitive to the prices of energy and energy related products in future years for which markets have not yet developed. Assumptions made to implement SFAS No. 157 had a significant effect on derivative values, and changes in assumptions may continue to have significant effects.

Total Level 3 derivative assets were 72 percent of our total assets measured at fair value, and Level 3 derivative liabilities were 94 percent of our total liabilities measured at fair value at September 30, 2008. A significant portion of our Level 3 derivative liabilities relate to the regulated company derivative contracts for which changes in fair value do not affect our earnings due to our use of regulatory accounting. Changes in fair value of these contracts are not material to our liquidity or capital resources because the costs and benefits of the contracts are recoverable from or refundable to customers on a timely basis.

Our regulated and unregulated business activities, that result in the recognition of derivative assets, create exposures to credit risk of energy marketing and trading counterparties. At September 30, 2008, we had $100.6 million of derivative assets exposed to counterparty credit risk that are contracted with multiple investment grade entities, $10.5 million with a government-backed entity, and $199.3 million related to a non-rated subsidiary of an investment grade company. We consider the credit ratings of these companies in our valuation of derivative assets and we use published probability of default indices based on the credit ratings of the counterparties to discount the value of the derivative asset. Changes in our counterparties   credit impact our ability to collect the derivative asset. Our derivative assets are primarily related to our regulated companies. Credit losses on regulated company contracts would not affect our earnings because these entities are cost-of-service regulated companies and costs of these contracts are recoverable from our customers. In addition, we consider our own credit rating in the valuation of derivative liabilities. The fair values of our derivative assets and liabilities were not impacted by changes in credit risk in the third quarter of 2008.

We review and update our fair value hierarchy classifications on a quarterly basis. As of September 30, 2008, investment securities are classified in Levels 1 and 2. Classification of an investment security or group of investment securities into Level 3 may occur if a significant amount of inputs to their valuation is no longer observable due to a decline in market activity or liquidity. We have assessed the impact of recently increasing market illiquidity on the valuation of our investments. Observable inputs remain available to value the classes of securities we own. We continue to monitor the liquidity of our securities and review our valuations to ensure proper classification within the fair value hierarchy.

Current market conditions are the key drivers of unrealized losses incurred on our investment securities. We consider unrealized losses to be other than temporary by nature because investment decisions are made by our trustee and thus we do not have the ability to hold securities until unrealized losses are recovered. Therefore, unrealized losses are recorded as realized losses in our condensed consolidated statements of income. For the three and nine months ended September 30, 2008, we recorded $2.6 million and $5.2 million, respectively, of after-tax unrealized losses incurred on our Rabbi Trust in other income, net on the condensed consolidated statements of income. These amounts were partially offset by $0.2 million and $0.5 million, respectively, of after-tax net realized gains on sales of investment securities. Losses related to the WMECO spent nuclear fuel trust are recorded as an increase to the spent nuclear fuel obligation and do not impact earnings.

For further information on derivative contracts, see Note 1C, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 2, "Derivative Instruments," to the condensed consolidated financial statements.

Goodwill Impairment: NU conducts goodwill impairment testing as of October 1 of each year. NU's remaining goodwill balance totaling $287.6 million relates to the acquisition of Yankee Gas in 2000. The testing of goodwill for impairment requires management to use estimates and judgment. Key factors that are considered in the impairment analysis include cash flow projections, interest rates, and recent comparable acquisition values. The company is in the process of completing the annual impairment test of the Yankee Gas goodwill as of October 1, 2008.

If, as a result of the impairment analysis, the estimated fair value of Yankee Gas is lower than its carrying value, then a second step of goodwill impairment testing would be required. The estimated fair value of Yankee Gas initially determined would be allocated to the assets and liabilities of Yankee Gas to determine the new value of goodwill. This new value would be compared to the carrying value of Yankee Gas goodwill, and any excess carrying value would be written off.

Income Taxes: Income tax expense is estimated annually for each of the jurisdictions in which we operate. This process involves estimating current and deferred income tax expense or benefit as impacted by earnings and the impact of temporary differences resulting from differing treatment of items, such as timing of the deduction and expenses, for tax and book accounting purposes, as well as, any impact of permanent differences resulting from tax credits, flow-through items, non-tax deductible expenses, etc. These differences result in deferred tax assets and liabilities that are included in the condensed consolidated balance sheets. The income tax estimation process impacts all of our segments. In accordance with the provisions of Accounting Principles Board (APB) No. 28, "Interim Financial Reporting," we record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates can significantly affect our condensed consolidated financial statements.

Part of the annual process in making adjustments to these estimates, as needed, is a reconciliation of the actual tax positions and amounts included on our income tax returns as filed in the fall of each year for the previous tax year to the estimates or provisions made during the income tax estimation process described above.

In the third quarter of 2008 and for the year ended December 31, 2007, the impact of these return to provision adjustments on income tax expense were as follows (in millions):

(Benefit)/Expense:		**2008**		**2007***
CL&P	$	(1.0)	$	3.3
PSNH		(1.3)		(0.4)
WMECO		(0.4)		(0.9)
Competitive businesses		(0.6)		(0.3)
Other		0.1		1.1
Total	$	(3.2)	$	2.8

*Represents the impacts of the return to provision for the year 2007 as recorded in the fourth quarter of 2007.

Other Matters

Contractual Obligations and Commercial Commitments: For updated information regarding our contractual obligations and commercial commitments at September 30, 2008, see Note 5B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the condensed consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes 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 these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward looking statements, including, but not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports filed with the SEC and we encourage you to consult such disclosures.

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each of which speaks only as of the date on which such statement is made, and we undertake no obligation to update 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 "Risk Factors" included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2007. This Quarterly Report on Form 10-Q also describes material contingencies and critical accounting policies and estimates in the accompanying "Management s Discussion and Analysis" and "Notes to Consolidated Financial Statements." We encourage you to review these items.

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

RESULTS OF OPERATIONS - NU CONSOLIDATED

The following table provides the variances in income statement line items for the condensed consolidated statements of income for NU included in this report on Form 10-Q for the three and nine months ended September 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Third Quarter	**Percent**	**Nine Months**	**Percent**
Operating Revenues	$ 56	4 %	$ (194)	(4) %
Operating Expenses:				
Fuel, purchased and net interchange power	(80)	(9)	(470)	(17)
Other operation	37	19	77	11
Maintenance	17	32	39	25
Depreciation	5	8	15	8
Amortization of regulatory assets, net	44	(a)	112	(a)
Amortization of rate reduction bonds	1	1	3	2
Taxes other than income taxes	6	9	7	3
Total operating expenses	30	2	(217)	(5)
Operating Income	26	21	23	6
Interest expense, net	9	15	19	11
Other income, net	7	65	5	13
Income before income tax expense	24	33	9	4
Income tax expense	1	5	(7)	(9)
Preferred dividends of subsidiary	-	-	-	-
Income from continuing operations	23	45	16	9
Income from discontinued operations	-	-	(1)	(100)
Net Income	$ 23	45 %	$ 15	9 %

(a) Percent greater than 100.

Net income was $23 million higher in the third quarter of 2008 primarily due to the growth in the company's transmission segment and was $15 million higher for the nine months primarily due to the growth in the company s transmission segment, partially offset by a $29.8 million after-tax charge associated with the settlement of litigation with Con Edison.

<u>Comparison of the Third Quarter of 2008 to the Third Quarter of 2007</u>

Operating Revenues

	For the Three Months Ended September 30,		
(Millions of Dollars)	**2008**	**2007**	**Variance**
Electric distribution	$ 1,284	$ 1,243	$ 41
Gas distribution	92	72	20
Total distribution	1,376	1,315	61
Transmission	108	69	39
Regulated companies	1,484	1,384	100
Competitive businesses	23	67	(44)
NU consolidated	$ 1,507	$ 1,451	$ 56

Operating revenues increased $56 million in 2008 primarily due to higher revenues from the regulated companies ($100 million), partially offset by lower revenues from competitive businesses ($44 million). The higher regulated company revenues were primarily due to the recovery of a higher level of CL&P and PSNH distribution related expenses passed through to customers through regulatory tracking mechanisms. Competitive business revenues decreased $44 million due to the continued exit from components of the competitive businesses.

Revenues from the regulated companies increased $100 million due to higher distribution segment revenues ($61 million) and higher transmission segment revenues ($39 million). Distribution segment revenues increased $61 million primarily due to higher electric distribution revenues ($41 million) and higher gas distribution revenues ($20 million). Transmission segment revenues increased $39 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues increased $41 million primarily due to the portion of revenues that does not impact earnings ($27 million) and the component of revenues that flows through to earnings ($14 million). The portion of electric distribution segment revenues that flows through to earnings increased $14 million primarily due to increases in retail rates at each of the regulated companies ($18 million), partially offset by lower retail electric sales ($3 million). Retail electric sales decreased 2.9 percent in 2008 compared with 2007. Gas distribution revenues increased $20 million primarily due to increased recovery of gas costs and higher sales volumes. Firm gas sales increased 13 percent in 2008 compared with 2007.

The $27 million electric distribution revenue increase that does not impact earnings is due to the components of CL&P, PSNH and WMECO retail revenues that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($62 million), partially offset by revenues that are eliminated in consolidation ($35 million). The distribution revenue tracking components increased $62 million primarily due to higher CL&P retail transmission revenues ($40 million) mainly as a result of the higher 2008 rates and higher CL&P wholesale revenues primarily due to an increase in the market price of energy relating to sales of independent power producers (IPP) generation to ISO-NE ($21 million) that benefits customers. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $80 million in 2008 due to lower costs at the regulated companies ($38 million) and lower expenses at the competitive businesses ($42 million). Fuel expense from the regulated companies decreased primarily due to lower CL&P and WMECO standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers and lower retail sales ($74 million), partially offset by higher Yankee Gas ($18 million) and PSNH fuel expense ($18 million). Competitive business fuel expenses decreased due to the continued exit from certain components of the competitive businesses.

Other Operation

Other operation expenses increased $37 million in 2008 primarily due to higher regulated companies distribution and transmission segment expenses ($44 million), partially offset by lower competitive business expenses ($6 million) and lower NU parent and other companies expenses ($1 million).

Higher regulated companies distribution and transmission segment expenses of $44 million are primarily due to higher distribution costs that are tracked and recovered through distribution tracking mechanisms ($72 million), partially offset by expenses that are eliminated in consolidation ($35 million). Competitive business expenses are lower by $6 million primarily due to lower operating costs at the remaining services businesses.

Maintenance

Maintenance expenses increased $17 million in 2008 primarily due to higher regulated companies distribution expenses ($9 million) and PSNH generation segment expenses mainly as a result of the Merrimack Station maintenance outages ($9 million), partially offset by lower transmission line expenses ($1 million). Regulated company distribution expenses are $9 million higher mainly as a result of higher overhead line maintenance expenses primarily due to more storm-related expenses ($7 million) and tree trimming ($2 million).

Depreciation

Depreciation increased $5 million in 2008 primarily due to higher transmission and distribution depreciation expense as a result of higher plant balances from completed construction programs put into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $44 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($49 million) resulting from a higher recovery of transition costs ($31 million), higher amortization of SBC ($12 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($7 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 million in 2008. The higher portion of principal within rate reduction bond payments resulted in a corresponding increase in the amortization of rate reduction bonds. This increase was partially offset by a decrease at PSNH resulting from the retirement of $50 million of rate reduction bonds in January 2008.

Taxes Other than Income Taxes

Taxes other than income taxes increased $6 million in 2008 primarily due to higher Connecticut gross earnings tax ($7 million) as a result of higher distribution revenues that are subject to gross earnings tax.

Interest Expense, Net

Interest expense, net increased $9 million in 2008 primarily due to higher long-term debt interest ($11 million) resulting from the issuance of new long-term debt in 2007 and 2008, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($3 million).

Other Income, Net

Other income, net increased $7 million in 2008 primarily due to interest income related to the 2008 federal tax settlement ($10 million) and higher AFUDC equity income ($4 million), partially offset by higher investment losses ($4 million) and lower investment income ($2 million).

Income Tax Expense

Income tax expense increased $1 million due primarily to tax settlement related interest income and other CL&P pre-tax earnings increases, partially offset by flow through impacts associated with depreciation and bad debt reserve changes. NU's current projected effective tax rate is lower than the statutory rate due primarily to temporary flow through depreciation benefits, Medicare subsidy and tax credits.

<u>Comparison of the First Nine Months of 2008 to the First Nine Months of 2007</u>

Operating Revenues

	For the Nine Months Ended September 30,		
(Millions of Dollars)	2008	2007	Variance
Electric distribution	$ 3,579	$ 3,781	$ (202)
Gas distribution	405	352	53
Total distribution	3,984	4,133	(149)
Transmission	281	202	79
Regulated companies	4,265	4,335	(70)
Competitive businesses	87	211	(124)
NU consolidated	$ 4,352	$ 4,546	$ (194)

Operating revenues decreased $194 million in 2008 primarily due to lower revenues from competitive businesses ($124 million) and lower revenues from the regulated companies ($70 million). Competitive business revenues decreased $124 million due to the continued exit from components of the competitive businesses. The lower regulated companies revenues were primarily due to the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms.

Revenues from the regulated companies decreased $70 million due to lower distribution segment revenues ($149 million), partially offset by higher transmission segment revenues ($79 million). Distribution segment revenues decreased $149 million primarily due to lower electric distribution revenues ($202 million), partially offset by higher gas distribution revenues ($53 million). Transmission segment revenues increased $79 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues decreased $202 million primarily due to the portion of revenues that does not impact earnings ($260 million), partially offset by the component of revenues that flows through to earnings ($58 million). The portion of the electric distribution segment that flows through to earnings increased $58 million primarily due to increases in retail rates at each of regulated companies ($72 million), partially offset by lower retail electric sales ($10 million). Retail electric sales decreased 3 percent in 2008 compared with 2007. Gas distribution revenues increased $53 million primarily due to increased recovery of gas costs and the rate increase effective July 1, 2007. Firm gas sales were unchanged in 2008 as compared with 2007.

The $260 million electric distribution revenue decrease that does not impact earnings is due to the components of CL&P, PSNH and WMECO retail revenues that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($184 million) and revenues that are eliminated in consolidation ($76 million). The distribution revenue tracking

components decreased $184 million primarily due to revenues associated with the recovery of generation service and related congestion charges ($220 million) and CL&P delivery-related FMCC ($68 million), partially offset by higher CL&P wholesale revenues primarily due to an increase in the market price of energy related to sales of IPP generation to ISO-NE ($69 million) and higher CL&P and PSNH retail transmission revenues ($46 million) mainly as a result of the higher 2008 rates. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $470 million in 2008 due to lower costs at the regulated companies ($334 million) and lower expenses at NU Enterprises ($136 million). Fuel expense from the regulated companies decreased primarily due to lower CL&P and WMECO standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers and lower retail sales ($402 million), partially offset by higher Yankee Gas ($35 million) and PSNH fuel expense ($33 million). Competitive business fuel expenses decreased due to the continued exit from certain components of the competitive businesses.

Other Operation

Other operation increased $77 million in 2008 primarily due to higher NU parent and other companies expenses ($47 million), higher regulated companies distribution and transmission segment expenses ($17 million) and higher competitive business expenses ($13 million).

NU parent and other companies' expenses are higher by $47 million in 2008 primarily due to the $49.5 million payment to Con Edison resulting from the settlement of litigation. Competitive business expenses are higher by $13 million primarily due to higher operating costs at the remaining services businesses.

Higher regulated company distribution and transmission segment expenses of $17 million are primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($88 million) and higher distribution segment expenses, partially offset by expenses that are eliminated in consolidation ($78 million).

Maintenance

Maintenance expenses increased $39 million in 2008 primarily due to higher regulated company distribution expenses ($28 million), higher generation segment expenses mainly related to the Merrimack Station maintenance outages ($10 million) and higher transmission line expenses ($1 million). Regulated company distribution expenses are $28 million higher mainly as a result of higher overhead line maintenance expenses due to more storm-related expenses ($13 million), tree trimming ($7 million), substation equipment ($3 million), line transformers ($2 million), and underground line activities ($1 million).

Depreciation

Depreciation increased $15 million in 2008 primarily due to higher transmission and distribution depreciation expense as a result of higher plant balances from completed construction programs put into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $112 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($116 million) resulting from a higher recovery of transition costs ($69 million), higher amortization of SBC ($27 million) and a credit in 2007 pertaining to the refund of the GSC provision for rate refunds ($22 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $3 million in 2008. The higher portion of principal within the rate reduction bond payments results in a corresponding increase in the amortization of rate reduction bonds. This increase was partially offset by a decrease at PSNH resulting from the retirement of $50 million of rate reduction bonds in January 2008.

Taxes Other than Income Taxes

Taxes other than income taxes increased $7 million in 2008 primarily due to higher Connecticut gross earnings tax ($9 million) mainly as a result of higher distribution revenues that are subject to gross earnings tax and higher property taxes at CL&P and PSNH ($3 million) as a result of higher plant balances, partially offset by lower payroll taxes ($3 million).

Interest Expense, Net

Interest expense, net increased $19 million in 2008 primarily due to higher long-term debt interest ($24 million) resulting from the issuance of new long-term debt in 2007 and the first half of 2008 and higher other interest ($3 million) mostly related to short-term debt, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($8 million).

Other Income, Net

Other income, net increased $5 million in 2008 primarily due to higher AFUDC equity income ($12 million), interest income related to the 2008 tax settlement ($10 million), and higher Energy Independence Act (EIA) incentives ($4 million), partially offset by the absence of the higher interest earned in 2007 on cash the parent received from the November 2006 sale of NU's competitive generation ($13 million) and higher investment losses ($7 million).

Income Tax Expense

Income tax expense decreased $7 million; $28 million from NU Parent and other including $20 million from the settlement of litigation with Con Edison and $8 million from other pre-tax expense increases, partially offset by pre-tax earnings related tax expense increases at CL&P ($20 million) and PSNH ($1 million). NU's current projected effective tax rate is lower than the statutory rate due primarily to temporary flow through depreciation benefits, Medicare subsidy and tax credits.

Income from Discontinued Operations

See Note 7, "Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

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

CL&P is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First and Second Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for CL&P included in this report on Form 10-Q for the three and nine months ended September 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	$ 62	7 %	$ (145)	(5) %
Operating Expenses:				
Fuel, purchased and net interchange power	(82)	(14)	(396)	(22)
Other operation	53	60	37	10
Maintenance	6	22	18	22
Depreciation	2	6	5	4
Amortization of regulatory assets, net	49	(a)	116	(a)
Amortization of rate reduction bonds	2	7	7	7
Taxes other than income taxes	5	11	5	4
Total operating expenses	35	4	(208)	(8)
Operating Income	27	37	63	30

Interest expense, net		3	7			6	6	
Other income, net		6	73			15	71	
Income before income tax		30	68			72	55	
Income tax expense		9	(a)			20	56	
Net Income	$	21	59	%	$	52	54	%

(a) Percent greater than 100.

Comparison of the Third Quarter of 2008 to the Third Quarter of 2007

Operating Revenues

Operating revenues increased $62 million in 2008 due to higher transmission segment revenues ($33 million) and higher distribution segment revenues ($29 million). Transmission segment revenues increased $33 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

The distribution segment revenues increased $29 million due to the component of revenues that flows through to earnings ($16 million) and the portion of revenues that does not impact earnings ($13 million). The portion that flows through to earnings increased $16 million primarily due to the rate increase effective February 1, 2008 ($17 million), partially offset by lower retail sales ($1 million). Retail sales decreased 2.7 percent in 2008 compared to the same period in 2007.

The $13 million distribution revenue increase that does not impact earnings is due to the components of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($38 million), partially offset by revenues that are eliminated in consolidation ($25 million). The distribution revenue DPUC approved tracking mechanisms that track the recovery of certain incurred costs increased $38 million primarily due to higher retail transmission revenues ($40 million) mainly as a result of the higher 2008 rates, higher wholesale revenues primarily due to an increase in the market price of energy relating to sales of IPP generation to ISO-NE ($21 million) that benefits customers and higher SBC revenues ($10 million), partially offset by a decrease in revenues associated with the recovery of GSC and related FMCC charges ($36 million). The lower GSC and FMCC revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, lower congestion costs and lower sales in 2008. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $82 million primarily due to a decrease in GSC supply costs ($42 million), a decrease in deferred fuel costs ($29 million) and lower other purchased power costs ($11 million), all of which are included in DPUC approved tracking mechanisms. The $42 million decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process. The $29 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC overrecovery in the third quarter of 2007 and a supply and delivery-related net FMCC underrecovery in the third quarter of 2008.

Other Operation

Other operation expenses increased $53 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($77 million) such as retail transmission ($37 million), reliability must run (RMR) ($30 million) and conservation and load management (C&LM) expenses ($6 million), and higher transmission segment expenses ($3 million), partially offset by expenses that are eliminated in consolidation ($25 million).

Maintenance

Maintenance expenses increased $6 million in 2008 primarily due to higher distribution overhead lines ($6 million), primarily due to more storms in the third quarter of 2008 compared to 2007.

Depreciation

Depreciation expense increased $2 million primarily due to higher utility plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $49 million primarily due to a higher recovery of transition costs ($31 million), a higher recovery of SBC ($12 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($7 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $2 million. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5 million primarily due to higher gross earnings taxes as a result of higher distribution revenues that are subject to gross earnings tax.

Interest Expense, Net

Interest expense, net increased $3 million primarily due to higher long-tem debt interest ($7 million) resulting from the $200 million debt issuance in September 2007 and the $300 million debt issuance in May 2008, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million) and lower short-term debt interest expense ($1 million).

Other Income, Net

Other income, net increased $6 million in 2008 primarily due to higher interest income related to the 2008 federal tax settlement ($6 million) and higher AFUDC equity income ($2 million) as a result of higher eligible CWIP due to the transmission construction program and lower short-term debt resulting in an increase in CWIP financed by equity, partially offset by higher investment losses ($3 million).

Income Tax Expense

Income tax expense increased $9 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with depreciation and bad debt reserve changes thereby reducing the effective tax rate.

Comparison of the First Nine Months of 2008 to the First Nine Months of 2007

Operating Revenues

Operating revenues decreased $145 million in 2008 due to lower distribution segment revenues ($223 million), partially offset by higher transmission segment revenues ($78 million).

The distribution segment revenues decreased $223 primarily due to the component of revenues that does not impact earnings ($270 million), partially offset by the component of revenues that flows through to earnings, which increased $48 million.

The $270 million distribution segment revenue decrease that does not impact earnings is due to the components of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($212 million) and revenues that are eliminated in consolidation ($59 million). The distribution revenue DPUC approved tracking mechanisms that track the recovery of certain incurred costs decreased $212 million primarily due to a decrease in revenues associated with the recovery of GSC and related FMCC ($278 million) and delivery-related FMCC ($68 million), partially offset by higher wholesale revenues primarily due to an increase in the market price of energy related to sales of IPP generation to ISO-NE ($69 million), higher retail transmission revenues ($32 million) mainly as a result of higher 2008 rates and higher SBC revenues ($27 million). The lower GSC and related FMCC revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, lower congestion costs and lower sales in 2008. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2008 as a result of lower RMR, VAR support and southwest Connecticut energy resource costs in 2008, as well as a larger prior year overrecovery being refunded to customers in 2008 as compared to 2007. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of the distribution segment that flows through to earnings increased $48 million primarily due to the rate increase effective February 1, 2008 ($57 million), partially offset by lower retail sales ($7 million). Retail sales decreased 3.6 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $78 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $396 million primarily due to a decrease in GSC supply costs ($237 million), a decrease in deferred fuel costs ($138 million) and lower other purchased power costs ($20 million), all of which are included in DPUC approved tracking mechanisms. The $237 million decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process. The $138 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC overrecovery in the first nine months of 2007 and a supply and delivery-related net FMCC underrecovery in the first nine months of 2008.

Other Operation

Other operation expenses increased $37 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($93 million) such as retail transmission ($29 million), RMR ($25 million), higher EIA expenses ($12 million), higher tracked administrative and general expenses ($8 million), higher uncollectibles ($8 million), higher C&LM expenses ($4 million), and higher transmission segment expenses ($5 million), partially offset by expenses that are eliminated in consolidation ($60 million).

Maintenance

Maintenance expenses increased $18 million in 2008 primarily due to higher distribution overhead line ($8 million), primarily due to more storms in 2008 compared to 2007, higher tree trimming expenses ($5 million), higher distribution substation equipment ($2 million), and higher line transformer activities ($2 million).

Depreciation

Depreciation expense increased $5 million primarily due to higher utility plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $116 million primarily due to a higher recovery of transition costs ($69 million), a credit in 2007 pertaining to the refund of the GSC overrecovery ($22 million) and higher recovery of SBC ($27 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $7 million. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $5 million primarily due to higher gross earnings taxes as a result of higher distribution revenues that are subject to gross earnings tax.

Interest Expense, Net

Interest expense, net increased $6 million primarily due to higher long-term debt interest ($16 million) resulting from the $200 million debt issuance in September 2007, the $300 million debt issuance in March 2007 and the $300 million debt issuance in May 2008, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($6 million) and lower short-term debt interest expense ($3 million).

Other Income, Net

Other income, net increased $15 million in 2008 primarily due to higher AFUDC equity income ($10 million) as a result of higher eligible CWIP due to the transmission construction program and lower short-term debt resulting in an increase in CWIP financed by equity, higher interest income related to the 2008 federal tax settlement ($6 million) and higher EIA incentives ($4 million), partially offset by higher investment losses ($5 million).

Income Tax Expense

Income tax expense increased $20 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with depreciation and bad debt reserve changes thereby reducing the effective tax rate.

LIQUIDITY

CL&P had positive consolidated operating cash flows of $202.2 million, after rate reduction bond payments, in the first nine months of 2008, compared with negative operating cash flows of $12.6 million, after rate reduction bond payments, in the first nine months of 2007. Operating cash flows in 2007 include tax payments of approximately $177.2 million related to the 2006 sale of NU's competitive generation business. Other drivers resulting in increased operating cash flows from 2007 were higher operating results after adjustments for reconciling items to net income, which included a year-to-date reduction in regulatory refunds and underrecoveries (net of income tax impacts). Regulatory refunds and underrecoveries decreased by $33 million from the six months ended June 30, 2008, primarily due to a $28 million deferral adjustment in the third quarter of 2008 for differences in transmission costs related to the Schedule 21 rates.

CL&P projects consolidated operating cash flows of approximately $300 million to $350 million in 2008, after approximately $170 million of rate reduction bond payments. This projection includes an expected income tax net settlement of approximately $40 million in the fourth quarter.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. CL&P s cash capital expenditures totaled $678.6 million in the first nine months of 2008, compared with $550.1 million in the first nine months of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

As of September 30, 2008, CL&P had borrowings of $188 million under the $400 million credit facility it shares with other NU subsidiaries. Other financing activities for the first nine months of 2008 included a $300 million issuance of 10-year bonds and capital contributions from NU parent of $137.4 million, offset by $79.8 million in common dividends paid to NU parent during the first nine months of 2008.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

Management s Discussion and Analysis of

Financial Condition and Results of Operations

PSNH is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU s Management s Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First and Second Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for PSNH included in this report on Form 10-Q for the three and nine months ended September 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Third Quarter	**Percent**	**Nine Months**	**Percent**
Operating Revenues	$ 17	6 %	$ 55	7 %
Operating Expenses:				
Fuel, purchased and net interchange power	18	13	34	8
Other operation	(3)	(7)	3	2
Maintenance	10	61	19	34
Depreciation	1	5	1	3
Amortization of regulatory assets/(liabilities), net	(4)	(62)	(4)	(97)
Amortization of rate reduction bonds	(2)	(14)	(5)	(12)
Taxes other than income taxes	-	-	1	3
Total operating expenses	20	8	49	7

Operating Income		(3)	(10)		6	7
Interest expense, net		2	14		3	8
Other income, net		2	(a)		4	(a)
Income/(Loss) before income tax		(3)	(12)		7	13
Income tax expense/(benefit)		(4)	(47)		1	3
Net Income	$	1	10 %	$	6	17 %

(a) Percent greater than 100.

<u>Comparison of the Third Quarter of 2008 to the Third Quarter of 2007</u>

Operating Revenues

Operating revenues increased $17 million in 2008 due to higher distribution segment revenues ($14 million) and higher transmission segment revenues ($3 million).

The distribution segment revenues increased $14 million primarily due to the portion of revenues that does not impact earnings ($15 million), partially offset by the component of revenues that flows through to earnings ($1 million). The portion of distribution segment revenues that flows through to earnings decreased $1 million primarily due to lower retail sales. Retail sales decreased 2.2 percent in 2008 compared to the same period in 2007.

The $15 million distribution revenue increase that does not impact earnings is due to the components of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($21 million), partially offset by revenues that are eliminated in consolidation ($7 million). The distribution revenue NHPUC approved tracking mechanisms that track the recovery of certain incurred costs increased $21 million primarily due to the pass-through of higher energy supply costs ($39 million) and higher retail transmission revenues ($3 million), partially offset by a decrease in the SCRC ($17 million) and lower REC revenue from the Northern Wood Power Plant ($3 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $3 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs increased $18 million primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired.

Other Operation

Other operation expenses decreased $3 million primarily due to expenses that are eliminated in consolidation ($7 million), partially offset by higher distribution segment expenses ($2 million), and higher transmission segment expenses ($1 million).

Maintenance

Maintenance expenses increased $10 million primarily due to higher generation segment expenses ($7 million) as a result of the Merrimack Station maintenance outages, higher hydro expenses ($1 million) primarily due to two major dam resurfacing projects and higher distribution lines ($1 million).

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net decreased $4 million primarily due to the reduction in net deferrals associated with PSNH's ES, transmission cost adjustment mechanism (TCAM) and SCRC tracking mechanisms ($3 million) and a net reduction in amortizations related to PSNH 's 2004 and 2007 rate case settlements ($2 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds decreased $2 million primarily due to the retirement of $50 million of rate reduction bonds in January 2008.

Interest Expense, Net

Interest expense, net increased $2 million primarily due to higher long-tem debt interest resulting from the $70 million debt issuance in September 2007 and the $110 million debt issuance in May 2008 ($3 million), partially offset by lower short-term debt interest expense ($1 million).

Other Income, Net

Other income, net increased $2 million primarily due to interest income related to the 2008 federal tax settlement resulting in a reduction to the effective tax rate.

Income Tax Expense

Income tax expense decreased $4 million primarily due to plant related flow through differences ($3 million), resulting in a reduction to the effective tax rate, and lower pre-tax earnings ($1 million).

Comparison of the First Nine Months of 2008 to the First Nine Months of 2007

Operating Revenues

Operating revenues increased $55 million in 2008 due to higher distribution segment revenues ($45 million) and higher transmission segment revenues ($11 million).

The distribution segment revenues increased $45 million primarily due to the portion of revenues that does not impact earnings ($33 million) and the component of revenues that flows through to earnings ($12 million). The portion of distribution segment revenues that flows through to earnings increased $12 million as a result of the rate increases effective July 1, 2007 and January 1, 2008 ($13 million), partially offset by lower retail sales ($1 million). Retail sales decreased 1.1 percent in 2008 compared to the same period in 2007.

The $33 million distribution revenue increase that does not impact earnings is due to the components of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($46 million), partially offset by revenues that are eliminated in consolidation ($13 million). The distribution revenue NHPUC approved tracking mechanisms that track the recovery of certain incurred costs increased $46 million primarily due to the pass-through of higher energy supply costs ($61 million), higher retail transmission revenues ($14 million), higher wholesale revenues ($8 million), partially offset by a decrease in the

SCRC ($41 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $11 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power costs increased $34 million primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired.

Other Operation

Other operation expenses increased $3 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($9 million) due to retail transmission, higher distribution segment expenses ($4 million) primarily due to higher customer account expenses and higher transmission segment expenses ($2 million), partially offset by expenses that are eliminated in consolidation ($13 million).

Maintenance

Maintenance expenses increased $19 million primarily due to higher fossil generation segment expenses ($9 million) primarily as a result of the Merrimack Station maintenance outages with the remainder of the increase primarily due to higher distribution segment expenses related to storms and the Reliability Enhancement Program (REP), which began on July 1, 2007.

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net decreased $4 million primarily due to the reduction in net deferrals associated with PSNH's ES, TCAM and SCRC tracking mechanisms ($7 million), offset in part by a net increase in amortization, primarily from PSNH's 2007 rate case settlement ($3 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds decreased $5 million primarily due to the retirement of $50 million of rate reduction bonds in January 2008.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $1 million primarily due to higher property taxes.

Interest Expense, Net

Interest expense, net increased $3 million primarily due to higher long-tem debt interest ($5 million) resulting from the $70 million debt issuance in September 2007 and the $110 million debt issuance in May 2008, partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million).

Other Income, Net

Other income, net increased $4 million primarily due to interest income related to the 2008 federal tax settlement ($2 million) and higher AFUDC equity income as a result of a higher eligible CWIP and lower short-term debt resulting in an increase in CWIP financed by equity ($2 million).

Income Tax Expense

Income tax expense increased $1 million primarily due to higher pre-tax earnings, partially offset by lower plant related flow through impacts resulting in a reduction to the effective tax rate.

LIQUIDITY

PSNH had consolidated operating cash flows of $64.7 million, after rate reduction bond payments, in the first nine months of 2008, compared with operating cash flows of $71.5 million, after rate reduction bond payments, in the first nine months of 2007. The decrease in 2008 operating cash flows was primarily due to an unfavorable shift in net working capital primarily related to taxes receivable.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. PSNH s cash capital expenditures totaled $164.8 million in the first nine months of 2008, compared with $113.1 million in the first nine months of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

As of September 30, 2008, PSNH had no borrowings outstanding under the $400 million credit facility it shares with other NU subsidiaries. Financing activities for the first nine months of 2008 included a $110 million issuance of 10-year bonds and capital contributions from NU parent of $46.6 million, offset by $27.3 million in common dividends paid to NU parent.

WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

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

WMECO is a wholly owned subsidiary of NU. This discussion should be read in conjunction with NU's Management's Discussion and Analysis of Financial Condition and Results of Operations, condensed consolidated financial statements and footnotes in this Form 10-Q, the First and Second Quarter 2008 Form 10-Q and the NU 2007 Form 10-K.

RESULTS OF OPERATIONS

The following table provides the variances in income statement line items for the condensed consolidated statements of income for WMECO included in this report on Form 10-Q for the three and nine months ended September 30, 2008:

	Income Statement Variances (Millions of Dollars) 2008 over/(under) 2007			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues	$ (1)	(1) %	$ (23)	(7) %
Operating Expenses:				
Fuel, purchased and net interchange power	8	13	(7)	(4)
Other operation	(7)	(32)	(16)	(21)
Maintenance	1	18	2	11
Depreciation	-	-	-	-
Amortization of regulatory assets, net	-	-	3	34
Amortization of rate reduction bonds	-	-	1	7
Taxes other than income taxes	-	-	-	-
Total operating expenses	2	2	(17)	(6)

Operating Income		(3)	(21)		(6)	(14)
Interest expense, net		-	-		-	-
Other income, net		1	(a)		1	65
Income/(loss) before income tax		(2)	(19)		(5)	(18)
Income tax expense		(2)	(43)		(3)	(26)
Net Income	$	-	- %	$	(2)	(12) %

(a) Percent greater than 100.

<u>Comparison of the Third Quarter of 2008 to the Third Quarter of 2007</u>

Operating Revenues

Operating revenues decreased $1 million in 2008 compared to the same period in 2007 due to lower distribution segment revenues ($2 million), partially offset by higher transmission segment revenues ($1 million).

The distribution segment revenues decreased $2 million primarily due to the component of revenues that flows through to earnings ($2 million) primarily due to a SQ performance assessment charge and lower retail sales. WMECO became subject to a SQ performance assessment charge for 2008 as a result of its reliability performance against the SQ metrics primarily as a result of significant storm activity. Retail sales decreased 5.6 percent in 2008 compared with 2007.

Transmission segment revenues increased $1 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $8 million primarily due to higher basic service supply costs, partially offset by an increased deferral of excess basic service expense over basic service revenue. The basic service supply costs are the contractual amounts we must pay to various suppliers that serve basic service load after winning a competitive solicitation process. To

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

Other Operation

Other operation expenses decreased $7 million primarily due to lower costs that are tracked and recovered through distribution tracking mechanisms ($6 million) such as retail transmission ($3 million), lower tracked administrative and general expenses ($2 million) mainly due to pension expense, and expenses that are eliminated in consolidation ($3 million), partially offset by higher distribution segment expenses ($1 million).

Maintenance

Maintenance expenses increased $1 million primarily due to higher underground distribution line maintenance primarily due to mandated DPU manhole rebuild work.

Other Income, Net

Other income, net increased $1 million in 2008 primarily due to interest income related to the 2008 federal tax settlement.

Income Tax Expense/(Benefit)

Income tax expense decreased $2 million primarily due to lower pre-tax earnings ($1 million) and refinements of estimates associated with plant related deferred taxes ($1 million).

Comparison of the First Nine Months of 2008 to the First Nine Months of 2007

Operating Revenues

Operating revenues decreased $23 million in 2008 due to lower distribution segment revenues ($26 million), partially offset by higher transmission segment revenues ($2 million).

The distribution segment revenues decreased $26 million primarily due to the portion of revenues that does not impact earnings ($24 million) and the component of revenues that flows through to earnings ($2 million). The $24 million distribution segment revenue decrease that does not impact earnings is due to the components of retail revenues that are included in DPU approved tracking mechanisms that track the recovery of certain incurred costs ($20 million) and revenues that are eliminated in consolidation ($4 million). The distribution revenue DPU approved tracking mechanisms that track the recovery of certain incurred costs decreased $20 million primarily due to lower wholesale revenue ($9 million), lower pension tracker and default service true-up revenues ($8 million) and lower generation service revenue resulting from declining sales and reduction in load caused by customer migration to third party suppliers ($3 million). Tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of the distribution segment that flows through to earnings decreased $2 million primarily due to lower retail sales ($2 million) and a service quality performance assessment charge ($1 million), partially offset by the rate increase effective January 1, 2008 ($2 million). Retail sales decreased 3.9 percent in 2008 compared to the same period in 2007.

Transmission segment revenues increased $2 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $7 million primarily due to the deferral of excess basic service expense over basic service revenue, partially offset by an increase in basic service supply costs. The basic service supply costs are the contractual amounts we must pay to various suppliers that serve basic service load after winning a competitive solicitation process. To the extent these costs do not match the revenues collected from customers, the DPU allows the difference to be deferred for future collection or refund.

Other Operation

Other operation expenses decreased $16 million primarily due to lower costs that are tracked and recovered through distribution tracking mechanisms ($14 million) such as retail transmission ($8 million), lower tracked administrative and general expenses ($6 million) mainly due to pension expense, lower expenses that are eliminated in consolidation ($5 million), partially offset by higher distribution segment expenses ($3 million) such as employee medical and uncollectibles.

Maintenance

Maintenance expenses increased $2 million primarily due to higher distribution line maintenance. Of this amount, $1 million is related to mandated DPU manhole rebuild work.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $3 million primarily due to the deferral of transition revenues collected in excess of allowed transition costs resulting mainly from higher power contract market values lowering power contract net costs.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $1 million. The higher portion of principal within the rate reduction bonds   payment results in a corresponding increase in the amortization of regulatory assets.

Other Income, Net

Other income, net increased $1 million in 2008 primarily due to interest income related to the 2008 federal tax settlement.

Income Tax Expense/(Benefit)

Income tax expense decreased $3 million primarily due to lower pre-tax earnings ($2 million) and refinements of estimates associated with plant related deferred taxes.

LIQUIDITY

WMECO had positive consolidated operating cash flows of $29.2 million, after rate reduction bond payments, in the first nine months of 2008, compared with negative operating cash flows of $4 million, after rate reduction bond payments, in the first nine months of 2007. The improvement in 2008 operating cash flows was primarily due to the payment of $47.9 million in federal and state income taxes in the first quarter of 2007, which was a result of the 2006 sale of NU   s competitive generation business and a favorable shift in net working capital, offset by a decrease in regulatory overrecoveries of approximately $34 million.

Cash capital expenditures included on the accompanying 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 portion of pension expense or income. WMECO s cash capital expenditures totaled $49.6 million in the first nine months of 2008, compared with $32.8 million in the first nine months of 2007. This increase was primarily the result of higher transmission capital expenditures in 2008.

As of September 30, 2008, WMECO had $19.9 million in borrowings outstanding under the $400 million credit facility it shares with other NU subsidiaries. Other financing activities for the first half of 2008 included a capital contribution from NU parent of $16.3 million, offset by $10.1 million in common dividends paid to NU parent.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

We utilize the sensitivity analysis methodology to disclose quantitative information for our commodity price risks (including where applicable capacity and ancillary components). Sensitivity analysis provides a presentation of the potential loss of future earnings, fair values or cash flows from market risk-sensitive instruments over a selected time period due to one or more hypothetical changes in commodity price components, or other similar price changes. Under sensitivity analysis, the fair value of the portfolio is a function of the underlying commodity components, contract prices and market prices represented by each derivative contract. For swaps, forward contracts and options, fair value reflects our best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Exchange-traded futures and options are recorded at fair value based on closing exchange prices. The fair value of our other contracts is based on models. As Select Energy's contract volumes are winding down and are substantially hedged against price risks, the company has limited exposure to commodity price risks.

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

A hypothetical change in the fair value of the wholesale portfolio was determined assuming a 10 percent change in forward market prices. At September 30, 2008, we calculated the market price resulting from a 10 percent change in forward market prices of those contracts. A 10 percent increase in prices for all products would have resulted in a pre-tax increase in fair value of $4 million and a 10 percent decrease in prices for all products would have resulted in a pre-tax decrease in fair value of $4.4 million. A 10 percent increase in energy prices would have resulted in a $3.2 million pre-tax decrease, and a 10 percent decrease in energy prices would have resulted in a $2.8 million pre-tax increase. A 10 percent increase/(decrease) in capacity prices would have resulted in a $1.8 million pre-tax increase/(decrease). A 10 percent increase/(decrease) in ancillary prices would have resulted in a $5.4 million pre-tax increase/(decrease).

The impact of a change in electricity prices on wholesale transactions at September 30, 2008 are not necessarily representative of the results that will be realized, if such a change were to occur. Also, energy, capacity and ancillaries have different market volatilities. The derivative contracts in the wholesale portfolio are accounted for at fair value, and changes in market prices impact earnings.

Other Risk Management Activities

Interest Rate Risk Management: We manage our interest rate risk exposure in accordance with our written policies and procedures by maintaining a mix of fixed and variable rate long-term debt. At September 30, 2008, approximately 91 percent (85 percent including the long-term debt subject to the fixed-to-floating interest rate swap as variable rate long-term debt) of our long-term debt, including fees and interest due for spent nuclear fuel disposal costs, was at a fixed interest rate. The remaining long-term debt is at variable interest rates and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in our variable interest rate, annual interest expense would have increased by a pre-tax amount of $3.8 million. At September 30, 2008, we maintained a fixed-to-floating interest rate swap at NU parent to manage the interest rate risk associated with its $263 million of fixed-rate long-term debt.

Credit Risk Management: Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of our contractual obligations. We serve a wide variety of customers and suppliers that include IPPs, industrial companies, gas and electric utilities, oil and gas producers, financial institutions, and other energy marketers. Margin accounts exist within this diverse group, and we realize interest receipts and payments related to balances outstanding in these margin accounts. This wide customer and supplier mix generates a need for a variety of contractual structures, products and terms that, in turn, require us to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by our risk management process.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is comprised of individuals from outside of the management of these activities that create these risk exposures and functions to ensure compliance with our stated risk management policies.

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

The NYMEX traded futures and option contracts cleared off the NYMEX exchange are ultimately guaranteed by NYMEX to Select Energy. Select Energy has established written credit policies with regard to its counterparties to minimize overall credit risk on all types of transactions. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash in advance, LOCs, and parent guarantees), and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in establishing credit limits prior to Select Energy entering into energy contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may impact Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions.

At September 30, 2008 and December 31, 2007, Select Energy had collateral balances deposited with counterparties of $11.6 million and $18.9 million, respectively, which is included in current assets - prepayments and other on the accompanying condensed consolidated balance sheets.

Our regulated companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. Our regulated companies manage the credit risk with these counterparties in accordance with established credit risk practices and maintain an oversight group that monitors contracting risks, including credit risk.

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks of the company. ERM involves the application of a well-defined, enterprise-wide methodology that will enable our Risk and Capital Committee, comprised of our senior officers, to oversee the identification, management and reporting of the principal risks of the business. However, there can be no assurances that the ERM process will identify every risk or event that could impact our financial condition or results of operations. The findings of this process are periodically discussed with our Board of Trustees.

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

ITEM 4.

CONTROLS AND PROCEDURES

NU, CL&P, PSNH and WMECO (the Companies) evaluated the design and operation of their disclosure controls and procedures at September 30, 2008 to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Exchange Act and the rules and regulations of the SEC. This evaluation was made under the supervision and with the participation of management, including the principal executive officer and principal financial officer of each respective Company, as of the end of the period covered by this report on Form 10-Q. The principal executive officer and principal financial officer of each respective Company have concluded, based on their review, that each Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by each Company in its respective reports under the Exchange Act (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 officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no changes in internal controls over financial reporting for any of the Companies during the quarter ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1.

LEGAL PROCEEDINGS

We are parties to various legal proceedings. We have identified these legal proceedings in Part I, Item 3, "Legal Proceedings" and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2007. Other than as set forth below, there have been no material changes with regard to the legal proceedings previously disclosed in our most recent Form 10-K, as modified by our disclosure under Item 1, "Legal Proceedings" in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2008 and June 30, 2008.

Yankee Companies v. U.S. Department of Energy

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

In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002 (the 2006 ruling) but did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December 2007, the Yankee Companies filed a second round of lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002. The application of any damages, which are ultimately recovered to benefit customers, is established in the Yankee Companies' FERC-approved rate settlement agreements, although implementation will be subject to the final determination of the FERC. CL&P, PSNH and WMECO expect to pass any recovery onto their customers; therefore, no earnings impact is expected to result.

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

ITEM 1A.

RISK FACTORS

NU is 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 - Other Matters." We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2007. NU s susceptibility to certain risks, including those discussed in detail in our Annual Report on Form 10-K, could exacerbate other risks. These risk factors should be considered carefully in evaluating NU s risk profile. There have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K.

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 common stock during the quarter ended September 30, 2008.

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)

*10.1

Ninth Supplemental Indenture of Mortgage dated as of October 1, 2008 between Yankee Gas Services Company and The Bank of New York Mellon Trust Company, N.A., successor as trustee to The Bank of New York, as successor to Fleet National Bank (formerly known as The Connecticut National Bank), as Trustee

*10.2

Special Severance Program for Officers of NU System Companies, Adopted by Northeast Utilities Board of Trustees on January 13, 1998; Amended and Restated effective January 1, 2009

*10.3

NU Incentive Plan, Amended, Restated and Adopted by Northeast Utilities Compensation Committee of the Board of Trustees on February 13, 2007 as Approved by Northeast Utilities Shareholders on May 8, 2007; Amended and Restated Effective January 1, 2009

*10.4

Northeast Utilities Deferred Compensation Plan for Executives, Adopted by Northeast Utilities Board of Trustees on January 13, 1998; Amended and Restated Effective January 1, 2009

*10.5

Supplemental Executive Retirement Plan for Officers of NU System Companies, Amended and Restated effective January 1, 2009

*10.6

Northeast Utilities Deferred Compensation Plan for Trustees, Adopted by Northeast Utilities Board of Trustees on January 22, 1980, Amended and Restated Effective January 1, 2009

*12

Ratio of Earnings to Fixed Charges

*15

Deloitte & Touche LLP Letter Regarding Unaudited Financial Information

*31

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 7, 2008

*31.1

Certification of David R. McHale, Senior 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 7, 2008

*32

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities and David R. McHale, Senior 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 7, 2008

Listing of Exhibits (CL&P)

*10

Release Agreement dated as of October 1, 2008, by and among Ambac Assurance Corporation, U.S. Bank National Association, as trustee with respect to the Bonds, The Connecticut Light and Power Company, and the Connecticut Development Authority

*10.1

First Amendment to Amended and Restated Loan Agreement, dated as of October 1, 2008, amending that certain Amended and Restated Loan Agreement made and dated as of January 1, 1997, by and between the Connecticut Development Authority and The Connecticut Light and Power Company

*10.2

First Amendment to Amended and Restated Indenture of Trust dated as of October 1, 2008, amending that certain Amended and Restated Indenture of Trust made and dated as of January 1, 1997, by and between the Connecticut Development Authority and U.S. Bank National Association (as successor-in-interest to Fleet National Bank)

*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 7, 2008

*31.1

Certification of David R. McHale, Senior 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 7, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of The Connecticut Light and Power Company and David R. McHale, Senior 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 7, 2008

Listing of Exhibits (PSNH)

*12

Ratio of Earnings to Fixed Charges

*31

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 7, 2008

*31.1

Certification of David R. McHale, Senior 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 7, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of Public Service Company of New Hampshire and David R. McHale, Senior 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 7, 2008

Listing of Exhibits (WMECO)

*12

Ratio of Earnings to Fixed Charges

*31

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company, required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated November 7, 2008

*31.1

Certification of David R. McHale, Senior 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 7, 2008

*32

Certification of Leon J. Olivier, Chief Executive Officer of Western Massachusetts Electric Company and David R. McHale, Senior 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 7, 2008

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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	November 7, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	November 7, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	November 7, 2008
	(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)

By	/s/	Date
	David R. McHale	
	David R. McHale	
	Senior Vice President and Chief Financial Officer	November 7, 2008
	(for the Registrant and as Principal Financial Officer)	