NORTHEAST UTILITIES
Form 10-Q
November 08, 2006

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, 2006

OR

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

For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134	02-0181050

Telephone: (603) 669-4000

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

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days:

Yes	**No**
√	

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

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

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

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, 2006
Northeast Utilities Common stock, $5.00 par value	154,022,864 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

GLOSSARY OF TERMS

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

NU COMPANIES, SEGMENTS OR INVESTMENTS:

CL&P	The Connecticut Light and Power Company
CRC	CL&P Receivables Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mount Tom generating plant
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company
NU or the company	Northeast Utilities
NU Enterprises	At September 30, 2006, NU's competitive subsidiaries include the merchant energy segment, which is comprised of Select Energy, NGC, NGS and the generation operations of Mt. Tom, and the energy services segment, which is comprised of E.S. Boulos Company, and NGS Mechanical, Inc., which are subsidiaries of NGS and SECI. For further information, see Note 12, "Segment Information," to the condensed consolidated financial statements.
PSNH	Public Service Company of New Hampshire
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
Utility Group	NU's regulated utilities comprised of the electric distribution and transmission businesses of CL&P, PSNH, WMECO, the generation business of PSNH and the gas distribution business of Yankee Gas. For further information, see Note 12 "Segment Information," to the condensed consolidated financial statements.
WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

THIRD PARTIES:

CYAPC	Connecticut Yankee Atomic Power Company
ECP	Energy Capital Partners

REGULATORS:

CSC	Connecticut Siting Council
DPUC	Connecticut Department of Public Utility Control
DTE	Massachusetts Department of Telecommunications and Energy
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER:

AFUDC	Allowance For Funds Used During Construction
CTA	Competitive Transition Assessment
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FMCC	Federally Mandated Congestion Cost
GSC	Generation Service Charge
Hess	Hess Corporation
ISO-NE	New England Independent System Operator
kWh	Kilowatt-Hour
kV	Kilovolt
LICAP	Locational Installed Capacity
LOCs	Letters of Credit
MW	Megawatt/Megawatts
NU 2005 Form 10-K	The Northeast Utilities and Subsidiaries combined 2005 Form 10-K as filed with the SEC
NYMEX	New York Mercantile Exchange
OCC	Connecticut Office of Consumer Counsel
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
RTO	Regional Transmission Organization
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SFAS	Statement of Financial Accounting Standards
TSO	Transitional Standard Offer

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

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 50,455	$ 45,782
Special deposits	34,413	103,789
Investments in securitizable assets	273,085	252,801
Receivables, less provision for uncollectible accounts of $21,033 in 2006 and $24,444 in 2005	331,836	901,516
Unbilled revenues	62,984	175,853
Taxes receivable	152,047	-
Fuel, materials and supplies	175,886	206,557
Marketable securities - current	62,193	56,012
Derivative assets - current	104,567	403,507
Prepayments and other	81,009	129,242
Assets held for sale	861,901	101,784
	2,190,376	2,376,843
Property, Plant and Equipment:		
Electric utility	6,929,584	6,378,838
Gas utility	853,718	825,872
Competitive energy	18,609	908,776
Other	277,621	254,659
	8,079,532	8,368,145
Less: Accumulated depreciation	2,600,329	2,551,322
	5,479,203	5,816,823
Construction work in progress	567,081	600,407
	6,046,284	6,417,230

Deferred Debits and Other Assets:		
Regulatory assets	2,100,555	2,483,851
Goodwill	287,591	287,591
Prepaid pension	265,076	298,545
Marketable securities - long-term	51,556	56,527
Derivative assets - long-term	274,263	425,049
Other	276,838	223,439
	3,255,879	3,775,002
Total Assets	$ 11,492,539	$ 12,569,075

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 278,000	$ 32,000
Long-term debt - current portion	26,309	22,673
Accounts payable	511,614	972,368
Accrued taxes	2,248	95,210
Accrued interest	62,309	47,742
Derivative liabilities - current	126,479	402,530
Counterparty deposits	220	28,944
Other	259,501	272,252
Liabilities of assets held for sale	349,055	101,511
	1,615,735	1,975,230
Rate Reduction Bonds	1,232,555	1,350,502
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,489,425	1,306,340
Accumulated deferred investment tax credits	33,346	95,444
Deferred contractual obligations	289,944	358,174
Regulatory liabilities	773,466	1,273,501
Derivative liabilities - long-term	153,158	272,995
Other	358,959	364,157
	3,098,298	3,670,611
Capitalization:		
Long-Term Debt	2,956,551	3,027,288

Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value - authorized 225,000,000 shares; 175,250,911 shares issued and 153,968,400 shares outstanding in 2006 and 174,897,704 shares issued and 153,225,892 shares outstanding in 2005	876,255	874,489
Capital surplus, paid in	1,444,695	1,437,561
Deferred contribution plan - employee stock ownership plan	(37,073)	(46,884)
Retained earnings	544,700	504,301
Accumulated other comprehensive income	5,463	19,987
Treasury stock, 19,680,010 shares in 2006 and 19,645,511 shares in 2005	(360,840)	(360,210)
Common Shareholders' Equity	2,473,200	2,429,244
Total Capitalization	5,545,951	5,572,732
Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 11,492,539	$ 12,569,075

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

NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME/(LOSS)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,594,096	$ 1,754,942	$ 5,402,545	$ 5,519,519
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	1,052,277	1,173,080	3,686,287	3,822,167
Other	248,154	268,350	823,626	785,839
Wholesale contract market changes, net	(4,781)	101,218	14,910	359,684
Restructuring and impairment charges	1,287	4,807	9,712	28,461
Maintenance	55,918	50,454	143,539	136,976
Depreciation	61,290	56,035	179,645	166,293
Amortization	(8,639)	79,902	48,755	127,021
Amortization of rate reduction bonds	49,161	46,123	141,836	133,029
Taxes other than income taxes	62,179	60,645	193,046	188,049
Total operating expenses	1,516,846	1,840,614	5,241,356	5,747,519
Operating Income/(Loss)	77,250	(85,672)	161,189	(228,000)
Interest Expense:				
Interest on long-term debt	40,105	33,928	112,632	96,984
Interest on rate reduction bonds	18,197	21,502	57,060	66,775
Other interest	4,479	3,864	18,105	15,178
Interest expense, net	62,781	59,294	187,797	178,937

Other Income, Net	13,871	11,768	41,967	27,962
Income/(Loss) from Continuing Operations Before				
Income Tax Benefit	28,340	(133,198)	15,359	(378,975)
Income Tax Benefit	(75,702)	(34,856)	(85,087)	(131,729)
Income/(Loss) from Continuing Operations Before				
Preferred Dividends of Subsidiary	104,042	(98,342)	100,446	(247,246)
Preferred Dividends of Subsidiary	1,390	1,390	4,169	4,169
Income/(Loss) from Continuing Operations	102,652	(99,732)	96,277	(251,415)
Discontinued Operations:				
Income from Discontinued Operations,				
Before Income Taxes	15,945	8,906	54,792	20,370
Loss from Sale of Discontinued Operations	(1,605)	-	(8,083)	-
Income Tax Expense	5,543	3,666	19,401	8,870
Income from Discontinued Operations	8,797	5,240	27,308	11,500
Net Income/(Loss)	$ 111,449	$ (94,492)	$ 123,585	$ (239,915)
Basic and Fully Diluted Earnings/(Loss) Per Common Share:				
Income/(Loss) from Continuing Operations	$ 0.67	$ (0.77)	$ 0.63	$ (1.94)
Income from Discontinued Operations	0.05	0.04	0.17	0.09
Basic and Fully Diluted Earnings/(Loss) Per Common Share	$ 0.72	$ (0.73)	$ 0.80	$ (1.85)
Basic Common Shares Outstanding (average)	153,883,480	129,957,408	153,651,610	129,585,519
Fully Diluted Common Shares Outstanding (average)	154,320,675	129,957,408	154,036,770	129,585,519

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,	
	2006	2005
	(Thousands of Dollars)	
Operating Activities:		
Net income/(loss)	$ 123,585	$ (239,915)
Adjustments to reconcile to net cash flows provided by operating activities:		
Wholesale contract market changes, net	2,089	359,684
Restructuring and impairment charges	9,202	53,194
Bad debt expense	25,665	21,758
Depreciation	182,752	175,443
Deferred income taxes	130,432	(122,012)
Amortization	48,755	127,021
Amortization of rate reduction bonds	141,836	133,029
Amortization of recoverable energy costs	6,481	22,158
Pension expense	20,626	24,699
Wholesale contract buyout payments	-	(145,231)
Regulatory refunds	(150,541)	(91,796)
Derivative assets and liabilities	(80,511)	4,466
Deferred contractual obligations	(72,255)	(67,065)
Other non-cash adjustments	940	52,303
Other sources of cash	9,375	-
Other uses of cash	(17,398)	(4,136)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	658,768	(1,137)
Fuel, materials and supplies	14,831	(33,979)
Investments in securitizable assets	(20,284)	(81,551)
Other current assets	23,533	48,984
Accounts payable	(461,183)	50,800

Counterparty deposits and margin special deposits		38,842		33,761
(Taxes receivable)/accrued taxes		(245,009)		32,332
Other current liabilities		(10,265)		(54)
Net cash flows provided by operating activities		380,266		352,756
Investing Activities:				
Investments in property and plant:				
Electric, gas and other utility plant		(583,083)		(508,116)
Competitive energy assets		(17,219)		(13,421)
Cash flows used for investments in property and plant		(600,302)		(521,537)
Net proceeds from sale of property		903		24,649
Cash payments for sales of competitive businesses		(19,429)		-
Proceeds from sales of investment securities		127,010		96,471
Purchases of investment securities		(123,319)		(108,944)
Rate reduction bond escrow		(54,357)		(8,069)
Other investing activities		2,971		15,291
Net cash flows used in investing activities		(666,523)		(502,139)
Financing Activities:				
Issuance of common shares		6,310		8,161
Issuance of long-term debt		250,000		300,000
Retirement of rate reduction bonds		(117,947)		(147,347)
Increase in short-term debt		246,000		128,000
Reacquisitions and retirements of long-term debt		(11,053)		(52,061)
Cash dividends on common shares		(83,560)		(64,785)
Other financing activities		1,180		16,620
Net cash flows provided by financing activities		290,930		188,588
Net increase in cash and cash equivalents		4,673		39,205
Cash and cash equivalents - beginning of period		45,782		46,989
Cash and cash equivalents - end of period	$	50,455	$	86,194

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 this complete report on Form 10-Q, the first and second quarter 2006 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 as part of the Northeast Utilities and subsidiaries combined 2005 Form 10-K (NU 2005 Form 10-K) with the SEC, and the current report on Form 8-K dated June 7, 2006 that updated the 2005 Form 10-K to present certain portions of the business as discontinued operations for all periods. 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, 2006, and the results of operations for the three and nine months ended September 30, 2006 and 2005 and cash flows for the nine months ended September 30, 2006 and 2005. The results of operations and statements of cash flows for the nine months ended September 30, 2006 and 2005 are not necessarily indicative of the results expected for a full year.

The condensed consolidated financial statements of NU and of 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.

In NU's condensed consolidated statements of income/(loss) and CL&P's, PSNH's and WMECO's condensed consolidated statements of income, the classification of expense amounts relating to compensation costs not recoverable from regulated customers, advertising costs, environmental charges and rate reduction bond service fees previously included in other income, net was changed to a preferable presentation. These expense amounts, which were reclassified to other operation expense for NU, CL&P, PSNH, and WMECO, totaled $3.9 million, $1.3 million, $1.1 million and $0.2 million, respectively, for the three months ended September 30, 2005. Similar amounts for the nine months ended September 30, 2005 for NU, CL&P, PSNH, and WMECO totaled $13.1 million, $4.1 million, $3 million and $0.6 million, respectively. These reclassifications had no impact on the companies' results of operations, cash flows, financial condition or changes in shareholders' equity.

NU's condensed consolidated statements of income/(loss) for all periods presented classify the operations for the following as discontinued operations, which were reflected in the report on Form 8-K dated June 7, 2006 and the second quarter 2006 report on Form 10-Q:

- Northeast Generation Company (NGC),
- The Mt. Tom generating plant (Mt. Tom) owned by Holyoke Water Power Company (HWP),
- Select Energy Services, Inc. (SESI) and its wholly owned subsidiaries HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC,
- A portion of Woods Electrical Co., Inc. (Woods Electrical),
-

Select Energy Contracting, Inc. - New Hampshire (SECI-NH) (including Reeds Ferry Supply Co., Inc. (Reeds Ferry)), a division of Select Energy Contracting, Inc. (SECI), and

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Woods Network Services, Inc. (Woods Network).

At September 30, 2006, all assets and liabilities of NGC and Mt. Tom have been classified as assets held for sale and liabilities of assets held for sale on the accompanying condensed consolidated balance sheet. At December 31, 2005, assets held for sale and liabilities of assets held for sale consisted of certain assets and liabilities of SESI and Woods Electrical. For further information regarding these companies, see Note 4, "Assets Held for Sale and Discontinued Operations."

B.

Accounting Standards Issued But Not Yet Adopted

Accounting for Servicing of Financial Assets: In March of 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 156, "Accounting for Servicing of Financial Assets - An Amendment of FASB Statement No. 140." SFAS No. 156 requires an entity to recognize a servicing asset or liability at fair value each time it undertakes an obligation to service a financial asset by entering into a servicing contract in a transfer of the servicer's financial assets that meets the requirements for sale accounting and in other circumstances. Servicing assets and liabilities may be subsequently measured through either amortization or recognition of fair value changes in earnings. SFAS No. 156 is required to be applied prospectively to transactions beginning in the first quarter of 2007 and may affect the accounting treatment of CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. Implementation of SFAS No. 156 is not expected to have a material effect on the company's financial statements.

Uncertain Tax Positions: On July 13, 2006, the FASB issued FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109." FIN 48 addresses the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. FIN 48 is required to be implemented prospectively in the first quarter of 2007 as a change in accounting principle with a cumulative effect adjustment reflected in the January 1, 2007 balance of retained earnings. The company is currently evaluating the potential impacts of FIN 48 on its financial statements.

Fair Value Measurements: On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is expected to be applied to fair value measurements of derivative contracts that are subject to mark-to-market accounting and other assets and liabilities reported at fair value. In most cases, SFAS No. 157 is required to be implemented prospectively with adjustments to fair value reflected as a cumulative effect adjustment to the opening balance of retained earnings as of January 1, 2008. The company is evaluating the potential impacts of SFAS No. 157 on its financial statements.

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans: On September 29, 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." Effective prospectively beginning on December 31, 2006, SFAS No. 158 requires balance sheet recognition of the funded status of pension and postretirement benefit plans, with the difference between the funded status and the accrued or prepaid position recognized as a charge or credit to shareholders' equity through other comprehensive income. The company is currently evaluating the potential balance sheet impacts of implementing SFAS No. 158 and whether NU's regulated companies will report regulatory assets or liabilities rather than charges or credits to shareholders' equity in recognition of the recovery of pension and postretirement expenses in rates. Implementing SFAS No. 158 could have a material negative effect on NU's and its subsidiaries shareholders' equity balances, the amount of which would depend upon the plans' funded status at December 31, 2006 and whether regulatory accounting is determined to apply to NU's regulated companies upon adoption of the standard. At December 31, 2005, the total difference between the funded status and the accrued or prepaid positions for NU's pension and postretirement plans was over $700 million on a pre-tax basis.

C.

Regulatory Accounting

The accounting policies of the Utility Group 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 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution businesses of CL&P, PSNH and WMECO, along with PSNH's generation business and Yankee Gas Services Company's (Yankee Gas) distribution business, continue to be cost-of-service rate regulated, and management believes that the application of SFAS No. 71 to those businesses continues to be appropriate. Management also believes that it is probable that the Utility Group will recover its investments in long-lived assets, including regulatory assets. In addition, all material net regulatory assets are earning an equity return, except for securitized regulatory assets, which are not supported by equity, and substantial portions of the unrecovered contractual obligations regulatory assets. Amortization and deferrals of regulatory assets are included on a net basis in amortization expense on the accompanying condensed consolidated statements of income/(loss).

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

	At September 30, 2006				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Recoverable nuclear costs	$ 14.7	$ -	$ -	$ 14.7	$ -
Securitized assets	1,182.8	743.2	338.2	101.4	-
Income taxes, net	374.0	295.8	13.5	46.9	17.8
Unrecovered contractual obligations	224.6	170.5	-	54.1	-
Recoverable energy costs	15.0	11.2	-	2.0	1.8
CTA and SBC undercollections	71.4	71.4	-	-	-
Other regulatory assets/(overrecoveries)	218.1	75.9	67.0	17.7	57.5
Totals	$ 2,100.6	$ 1,368.0	$ 418.7	$ 236.8	$ 77.1

	At December 31, 2005				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Recoverable nuclear costs	$ 44.1	$ -	$ 26.1	$ 18.0	$ -
Securitized assets	1,340.9	855.6	375.0	110.3	-
Income taxes, net	332.5	227.6	35.9	51.6	17.4
Unrecovered contractual obligations	327.5	197.7	63.2	66.6	-
Recoverable energy costs	193.0	7.3	171.5	2.5	11.7
Other regulatory assets/(overrecoveries)	245.9	69.8	150.3	(25.8)	51.6
Totals	$ 2,483.9	$ 1,358.0	$ 822.0	$ 223.2	$ 80.7

At September 30, 2006, CL&P's Competitive Transition Assessment (CTA) was recorded as a $65.6 million regulatory asset as CTA unrecovered costs were in excess of CTA collections due to refunds to customers. At December 31, 2005, CTA collections were in excess of CTA costs, and a $26 million regulatory liability was recorded. The change relates to refunds made to customers between January and August of 2006 ordered by the Connecticut Department of Public Utility Control (DPUC) in anticipation of future overrecoveries.

Included in NU's other regulatory assets/(overrecoveries) above are regulatory assets recorded in accordance with FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," totaling $53.3 million at September 30, 2006 and $47.3 million at December 31, 2005. A portion of these asset retirement obligations regulatory assets totaling $17.8 million at September 30, 2006 and $17.3 million at December 31, 2005 has been approved for future recovery. At this time, management believes that the remaining regulatory assets are also probable of recovery.

The restructuring settlement agreement between PSNH and the state of New Hampshire, which was implemented in May of 2001, requires that non-securitized stranded costs be recovered from PSNH's customers prior to a recovery end date of October 31, 2007. On June 30, 2006, under the terms of the restructuring settlement agreement, PSNH completed the recovery of its non-securitized stranded costs and offset the remaining stranded cost regulatory asset balances totaling $345.8 million against an offsetting regulatory liability for the cumulative deferral of Stranded Cost Recovery Charge (SCRC) revenues. At September 30, 2006, PSNH had $338.2 million of Part 1 securitized stranded costs and $26.2 million of Part 2 non-securitized stranded costs, including $6.5 million of SCRC costs in excess of SCRC revenues. This amount is a reconciling item that will be included in the calculation of the 2007 SCRC rate.

Included in WMECO's other regulatory assets/(overrecoveries) are $20.2 million and $37.8 million at September 30, 2006 and December 31, 2005, respectively, of amounts related to WMECO's rate cap deferral. The rate cap deferral allows WMECO to recover stranded costs, and these amounts represent the cumulative excess of transition cost revenues over transition cost expenses.

Additionally, the Utility Group had $15.3 million and $11.2 million of costs at September 30, 2006 and December 31, 2005, respectively, that are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. These amounts represent costs that have not yet been approved by the applicable regulatory agency. Management believes these assets are recoverable in future cost of service regulated rates.

As discussed in Note 7D, "Commitments and Contingencies - Deferred Contractual Obligations," substantial portions of the unrecovered contractual obligations regulatory assets have not yet been approved for recovery. On August 15, 2006, a settlement agreement was filed with the Federal Energy Regulatory Commission (FERC) that, if approved, would allow for the collection of these costs. Management expects that the FERC will rule on the settlement agreement by the end of 2006 and believes that these regulatory assets are probable of recovery.

Regulatory Liabilities: The Utility Group had $773.5 million of regulatory liabilities at September 30, 2006 and $1.3 billion at December 31, 2005, including revenues subject to refund. These amounts are comprised of the following:

	At September 30, 2006				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Cost of removal	$ 296.3	$ 136.8	$ 80.9	$ 23.8	$ 54.8
CL&P GSC overcollections	54.9	54.9	-	-	-
Regulatory liabilities offsetting Utility Group derivative assets	290.2	290.2	-	-	-
Other regulatory liabilities	132.1	57.9	43.5	0.1	30.6
Totals	$ 773.5	$ 539.8	$ 124.4	$ 23.9	$ 85.4

	At December 31, 2005				
(Millions of Dollars)	**NU Consolidated**	**CL&P**	**PSNH**	**WMECO**	**Yankee Gas and Other**
Cost of removal	$ 305.5	$ 139.4	$ 85.7	$ 23.6	$ 56.8
CL&P CTA, GSC and SBC overcollections	154.0	154.0	-	-	-
PSNH cumulative deferral - SCRC	303.3	-	303.3	-	-
Regulatory liabilities offsetting Utility Group derivative assets	391.2	391.2	-	-	-
Other regulatory liabilities	119.5	58.4	25.6	0.2	35.3
Totals	$ 1,273.5	$ 743.0	$ 414.6	$ 23.8	$ 92.1

For information regarding derivative assets, see Note 5, "Derivative Instruments."

D.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) is a non-cash item that is included in the cost of Utility Group 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 in other interest expense, and the cost of equity funds is recorded as other income on the condensed consolidated statements of income/(loss), as follows:

	For the Three Months Ended		**For the Nine Months Ended**	
(Millions of Dollars)	**September 30, 2006**	**September 30, 2005**	**September 30, 2006**	**September 30, 2005**
Borrowed funds	$3.3	$2.7	$ 9.4	$ 6.9
Equity funds	4.2	3.7	10.5	7.9
Totals	$7.5	$6.4	$19.9	$14.8
Average AFUDC rates	7.5%	6.2%	6.9%	5.3%

The average Utility Group AFUDC rate is based on a FERC prescribed formula that develops 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 eligible construction work in progress amounts to calculate AFUDC. Fifty percent of construction work in progress (CWIP) of CL&P's four major transmission projects in southwest Connecticut is recovered currently in rates for the portion under FERC jurisdiction. The increase in AFUDC from borrowed and equity funds during the three and nine months ended September 30, 2006 as compared to the three and nine months ended September 30, 2005 results from higher levels of CWIP due to CL&P's transmission projects, PSNH's Northern Wood project and Yankee Gas' liquefied natural gas project. The increase in the average AFUDC rate in 2006 is primarily due to the increased CWIP being financed by permanent capital and higher short-term debt rates.

E.

Share-Based Payments

NU maintains an Employee Stock Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan). In the first quarter of 2006, NU adopted SFAS No. 123(R), "Share-Based Payments," under the modified prospective method. Adoption of SFAS No. 123(R) had a de minimus effect on NU's net income/(loss) and no effect on NU's income/(loss) per share. For the nine months ended September 30, 2006, a tax benefit in excess of compensation cost totaling $0.5 million increased cash flows from financing activities.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based

Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

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

- For grants of restricted stock and restricted stock units (RSUs), NU continues to record compensation expense over the vesting period based upon the fair value of NU's common stock at the date of grant, but records this expense net of estimated forfeitures. Previously, forfeitures were recorded as they occurred. Dividend equivalents on RSUs, previously included in compensation expense, are charged to retained earnings net of estimated forfeitures.

- For shares granted under the ESPP, an immaterial amount of compensation expense was recorded in the first quarter of 2006, and no future compensation expense was recorded in the second and third quarters of 2006 or will be recorded in future periods as a result of a plan amendment that was effective on February 1, 2006.

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

Incentive Plans: Under the Incentive Plan, NU is authorized to grant new shares for various types of awards, including restricted shares, restricted share units, performance units, and stock options to eligible employees and board members. The number of shares that may be utilized for grants and awards during a given calendar year may not exceed the aggregate of one percent of the total number of NU common shares outstanding as of the first day of that calendar year plus the shares not utilized in previous years.

Restricted Shares and Restricted Share Units: NU has granted restricted shares under the 2002, 2003 and 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004, 2005 and 2006 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares plus cash sufficient to satisfy withholdings subsequent to vesting. A summary of restricted shares and RSUs for the nine months ended September 30, 2006 is as follows:

Restricted Shares	**Restricted Shares**	**Weighted Average Grant - Date Fair Value**	**Total Weighted Average Grant - Date Fair Value (Millions)**	**Remaining Compensation Cost (Millions)**	**Weighted Average Remaining Period (Years)**
Outstanding at December 31, 2005	152,901	N/A			
Granted	-	-			
Vested	(74,243)	$14.52	$1.1		
Forfeited	(1,388)	$14.17			
Outstanding at March 31, 2006	77,270	$14.87	$1.1	$1.0	1.0
Granted	-	-	-		
Vested	-	-	-		
Forfeited	(3,405)	$14.14			
Outstanding at June 30, 2006	73,865	$14.90	$1.1	$0.7	0.8
Granted	-	-			
Vested	-	-			
Forfeited	(3,952)	$14.14			
Outstanding at September 30, 2006	69,913	$14.95	$1.0	$0.4	0.6

The per share and total weighted average grant date fair value for restricted shares vested was $14.60 and $1.4 million, respectively, for the nine months ended September 30, 2005. No shares vested during the three months ended September 30, 2005.

The total compensation cost recognized during the three and nine months ended September 30, 2006 was $0.1 million and $0.4 million, net of taxes of approximately $0.1 million and $0.3 million, respectively. The total compensation cost recognized during the three and nine months ended September 30, 2005 was $0.2 million and $0.5 million, net of taxes of approximately $0.1 million and $0.3 million, respectively.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Weighted Average Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2005	521,273	N/A			
Granted	352,783	$19.66			
Issued	(109,579)	$18.43	$ 2.0		
Forfeited	(5,604)	$18.93			
Outstanding at March 31, 2006	758,873	$19.27	$14.6	$11.6	2.4
Granted	6,244	$20.67			
Issued	(2,516)	$19.11	-		
Forfeited	(18,870)	$19.19			
Outstanding at June 30, 2006	743,731	$19.40	$14.4	$10.0	2.1
Granted	5,876	$23.27			
Issued	(2,693)	$19.19	$ 0.1		
Forfeited	(9,713)	$19.37			
Outstanding at September 30, 2006	737,201	$19.33	$14.3	$ 8.1	2.0

The weighted average grant date fair value per share for RSUs granted during the three and nine months ended September 30, 2005 was $19.95 and $18.81, respectively. The weighted average grant date fair value per share for RSUs paid during the three and nine months ended September 30, 2005 was $19.02 and $19.06, respectively. The total weighted average fair value of RSUs paid during the three and nine months ended September 30, 2005 was approximately $48 thousand and $1.9 million, respectively.

The total compensation cost recognized for the three and nine months ended September 30, 2006 was $0.7 million and $2.1 million, respectively, net of taxes of approximately $0.5 million and $1.4 million, respectively. The total compensation cost recognized during the three and nine months ended September 30, 2005 was $0.3 million and $1.4 million, net of taxes of approximately $0.2 million and $0.9 million, respectively.

Stock Options: Prior to 2003, NU granted stock options to certain employees. These options were fully vested as of December 31, 2005. The fair value of each stock option grant was estimated on the date of grant using the

Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding at September 30, 2006 is 4 years.

A summary of stock option transactions is as follows:

		Exercise Price Per Share			
	Options	**Range**			**Weighted Average**
Outstanding - December 31, 2005	**1,122,541**	**$14.9375**	-	**$22.2500**	**$18.4484**
Exercised	(8,166)	$16.3100	-	$19.5000	$17.7861
Forfeited and cancelled	(18,750)	$21.0300	-	$21.0300	$21.0300
Outstanding and Exercisable - March 31, 2006	**1,095,625**	**$14.9375**	-	**$22.2500**	**$18.4091**
Exercised	(51,817)	$14.9375	-	$19.5000	$17.9485
Forfeited and cancelled	-	N/A	-	N/A	$ -
Outstanding and Exercisable - June 30, 2006	**1,043,808**	**$14.9375**	-	**$22.2500**	**$18.4320**
Exercised	(106,338)	$14.9375	-	$19.8700	$17.7315
Forfeited and cancelled	(6,600)	$21.0300	-	$21.0300	$21.0300
Outstanding and Exercisable - September 30, 2006	**930,870**	**$14.9375**	-	**$22.2500**	**$18.4936**

Cash received for options exercised during the three and nine months ended September 30, 2006 totaled $2 million and $3.2 million, respectively.

Employee Share Purchase Plan: NU maintains an ESPP for all eligible employees. Prior to February 1, 2006, NU common shares were purchased by employees at six-month intervals at 85 percent of the lower of the price on the first or last day of each six-month period. Employees were permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the purchase period. Effective February 1, 2006, the ESPP was amended to change the discount rate to 5 percent of the closing market price on the last day of the purchase period. As a result, the ESPP qualifies as a non-compensatory plan under SFAS No. 123(R), and no compensation expense will be recorded for ESPP purchases.

Pro Forma Impact: The following table illustrates the pro forma effect if NU had applied the recognition provisions of SFAS No. 123 to share-based compensation:

	For the Three Months Ended September 30, 2005		For the Nine Months Ended September 30, 2005	
Net loss, as reported	$	(94.5)	$	(239.9)
Add: Share-based payments included in reported net loss, net of related tax effects		0.5		1.9
Net loss before share-based payments		(94.0)		(238.0)
Deduct: Total share-based payments determined under the fair value-based method for all awards, net of related tax effects		(0.7)		(2.5)
Pro forma net loss	$	(94.7)	$	(240.5)
Loss Per Share:				
Basic and fully diluted - as reported	$	(0.73)	$	(1.85)
Basic and fully diluted - pro forma	$	(0.73)	$	(1.86)

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards.

F.

Sale of Customer Receivables

At September 30, 2006 and December 31, 2005, CL&P had sold an undivided interest in its accounts receivable of $100 million and $80 million, respectively, to a financial institution with limited recourse through the CRC, a consolidated, wholly-owned subsidiary of CL&P. CRC can sell up to $100 million of an undivided interest in its accounts receivable and unbilled revenues. At September 30, 2006 and December 31, 2005, the reserve requirements calculated in accordance with the Receivables Purchase and Sale Agreement were $20.6 million and $21 million, respectively. These reserve amounts are deducted from the amount of receivables eligible for sale. At their present levels, these reserve amounts do not limit CL&P's ability to access the full amount of the facility. Concentrations of credit risk to the purchaser under this agreement with respect to the receivables are limited due to CL&P's diverse customer base.

At September 30, 2006 and December 31, 2005, amounts sold to CRC by CL&P but not sold to the financial institution totaling $273.1 million and $252.8 million, respectively, are included in investments in securitizable assets on the accompanying condensed consolidated balance sheets. These amounts would be excluded from CL&P's assets in the event of CL&P's bankruptcy. On July 5, 2006, CRC renewed the bank commitment for the Receivables Purchase and Sale Agreement with CL&P and the financial institution through July 3, 2007 to coincide with the date this agreement terminates, unless otherwise extended. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to servicing those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities - A Replacement of SFAS No. 125." See Note 1B, "Accounting Standards Issued But Not Yet Adopted," for further information.

G.

Investment in CYAPC

The operating subsidiaries of NU collectively own 49 percent of the common stock of Connecticut Yankee Atomic Power Company (CYAPC) with a carrying value of $20.8 million at September 30, 2006 and $22.7 million at December 31, 2005. These amounts are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. On August 15, 2006, a settlement agreement was filed with the FERC that, if approved, would allow for the recovery of CYAPC's decommissioning and plant closure costs. For further information, see Note 7D, "Commitments and Contingencies - Deferred Contractual Obligations," Note 1C, "Summary of Significant Accounting Policies - Regulatory Accounting," and Note 1K, "Summary of Significant Accounting Policies - Other Income, Net."

H.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, overdraft amounts are reclassified from cash and cash equivalents to accounts payable.

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I.

Special Deposits

Special deposits represent amounts Select Energy, Inc. (Select Energy) has on deposit with unaffiliated counterparties and brokerage firms in the amount of $34.4 million and $103.8 million at September 30, 2006 and December 31, 2005, respectively. SESI special deposits totaling $10.2 million at December 31, 2005 are included in assets held for sale on the accompanying condensed consolidated balance sheets. SESI was sold in the second quarter of 2006.

J.

Counterparty Deposits

Balances collected from counterparties resulting from Select Energy's credit management activities totaled $0.2 million at September 30, 2006 and $28.9 million at December 31, 2005. These amounts are recorded as current liabilities and included as counterparty deposits on the accompanying condensed consolidated balance sheets. To the extent Select Energy requires collateral from counterparties, cash is received as a part of the total collateral required. The right to use such cash collateral in an unrestricted manner is determined by the terms of Select Energy's agreements. Key factors affecting the unrestricted status of a portion of this cash collateral include the financial standing of Select Energy and of NU as its credit supporter.

K.

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, 2006**	**September 30, 2005**	**September 30, 2006**	**September 30, 2005**
Other Income:				
Investment income	$ 6.5	$ 4.3	$ 19.0	$ 12.9
CL&P procurement fee	3.0	3.1	8.5	9.0

AFUDC - equity funds		4.2		3.7		10.5		7.9
Gain on sale of investment in Globix		-		-		3.1		-
Other		3.1		3.0		10.1		9.1
Total Other Income	$	16.8	$	14.1	$	51.2	$	38.9
Other Loss:								
Charitable donations	$	(0.8)	$	(0.4)	$	(2.2)	$	(2.1)
Lobbying costs		(1.0)		(0.7)		(3.5)		(2.7)
Loss on investments in securitizable assets		(0.6)		(0.3)		(1.7)		(1.1)
Other		(0.5)		(0.9)		(1.8)		(5.0)
Total Other Loss	$	(2.9)	$	(2.3)	$	(9.2)	$	(10.9)
Total Other Income, Net	$	13.9	$	11.8	$	42.0	$	28.0

CL&P	**For the Three Months Ended**				**For the Nine Months Ended**			
(Millions of Dollars)	**September 30, 2006**		**September 30, 2005**		**September 30, 2006**		**September 30, 2005**	
Other Income:								
Investment income	$	4.1	$	2.8	$	11.8	$	7.7
CL&P procurement fee		3.0		3.1		8.5		9.0
AFUDC - equity funds		2.6		3.2		6.1		6.7
Energy Independence Act incentives		1.0		-		3.5		-
Other		1.5		2.0		3.9		4.2
Total Other Income	$	12.2	$	11.1	$	33.8	$	27.6
Other Loss:								
Charitable donations	$	(0.5)	$	(0.3)	$	(1.3)	$	(1.2)
Lobbying costs		(0.6)		(0.3)		(2.4)		(1.4)
Loss on investments in securitizable assets		(0.6)		(0.3)		(1.7)		(1.1)
Other		(0.3)		(0.2)		(0.8)		(1.8)
Total Other Loss	$	(2.0)	$	(1.1)	$	(6.2)	$	(5.5)
Total Other Income, Net	$	10.2	$	10.0	$	27.6	$	22.1

PSNH	**For the Three Months Ended**				**For the Nine Months Ended**			
(Millions of Dollars)	**September 30, 2006**		**September 30, 2005**		**September 30, 2006**		**September 30, 2005**	
Other Income:								
Investment income	$	0.1	$	0.1	$	0.6	$	0.5
AFUDC - equity funds		1.1		0.2		3.4		0.7
Conservation and load management incentive		-		-		-		0.6
Gain on disposition of property		-		0.6		-		0.6
Other		0.1		0.1		0.2		0.2
Total Other Income	$	1.3	$	1.0	$	4.2	$	2.6
Other Loss:								
Charitable donations	$	(0.2)	$	(0.1)	$	(0.5)	$	(0.4)
Lobbying costs		(0.1)		(0.1)		(0.5)		(0.5)
Other		(0.1)		(0.7)		(0.3)		(0.6)
Total Other Loss	$	(0.4)	$	(0.9)	$	(1.3)	$	(1.5)
Total Other Income, Net	$	0.9	$	0.1	$	2.9	$	1.1

WMECO	**For the Three Months Ended**				**For the Nine Months Ended**			
(Millions of Dollars)	**September 30, 2006**		**September 30, 2005**		**September 30, 2006**		**September 30, 2005**	
Other Income:								
Investment income	$	0.3	$	0.2	$	0.4	$	0.4
Conservation and load management incentive		0.2		0.4		0.8		0.6
Millstone 1 recovery amortization		0.2		0.2		0.7		0.7
Other		0.1		0.3		0.4		0.5
Total Other Income	$	0.8	$	1.1	$	2.3	$	2.2
Other Loss:								
Charitable donations	$	(0.1)	$	-	$	(0.2)	$	(0.2)
Lobbying costs		(0.1)		(0.1)		(0.4)		(0.4)
Other		-		-		(0.1)		(0.2)
Total Other Loss	$	(0.2)	$	(0.1)	$	(0.7)	$	(0.8)
Total Other Income, Net	$	0.6	$	1.0	$	1.6	$	1.4

Investment income for NU includes equity in earnings/(losses) of regional nuclear generating and transmission companies of $0.8 million and $0.6 million for the three months ended September 30, 2006 and 2005, respectively, and $(0.4) million and $2.5 million for the nine months ended September 30, 2006 and 2005, respectively. Equity in earnings relates to NU, CL&P, PSNH and WMECO's investment in CYAPC, Maine Yankee Atomic Power Company (MYAPC), Yankee Atomic Electric Company (YAEC) (Yankee companies) and the Hydro-Quebec transmission system.

Based on developments in July of 2006, CYAPC management concluded that $10 million of CYAPC's regulatory assets were no longer probable of recovery and should be written off. Because the contingency surrounding these regulatory assets existed at June 30, 2006, the write-off was recorded in the second quarter. NU recorded a total after-tax write-off of $3 million ($2.1 million, $0.3 million and $0.6 million for CL&P, PSNH and WMECO, respectively) for its ownership share of this charge, which is included in investment income for the nine months ended September 30, 2006 in the tables above. For further information regarding CYAPC, see Note 7D, "Commitments and Contingencies - Deferred Contractual Obligations," and Note 1C, "Summary of Significant Accounting Policies - Regulatory Accounting."

None of the amounts in either other income - other or other loss - other are individually significant.

2.

WHOLESALE CONTRACT MARKET CHANGES (NU, NU Enterprises)

NU recorded a pre-tax benefit of $4.8 million and a pre-tax charge of $101.2 million for wholesale contract market changes in the three months ended September 30, 2006 and 2005, respectively, and charges of $14.9 million and $359.7 million for the nine months ended September 30, 2006 and 2005, respectively. Wholesale contract market changes are changes in the fair value of wholesale contracts being divested. These changes are comprised of the following items:

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A benefit of $4.6 million and charges of $14.1 million for the three and nine months ended September 30, 2006 and charges of $80.6 million and $439.1 million for the three and nine months ended September 30, 2005, respectively, associated with the mark-to-market on certain long-dated wholesale electricity contracts in New England, New York and PJM and contracts to purchase generation products in New England and New York. The decision in March of 2005 to exit the wholesale marketing business changed management's conclusion regarding the likelihood that these wholesale marketing contracts would result in

physical delivery to customers. This in turn resulted in a change in the first quarter of 2005 from accrual accounting to mark-to-market accounting for the wholesale marketing contracts. Included in the third quarter 2005 charge of $80.6 million is a pre-tax charge of $11.7 million related to a portfolio of contracts that Select Energy assigned to a third-party wholesale power marketer, obligating that marketer to assume responsibility for those contracts that Select Energy had in New England, beginning on January 1, 2006, in exchange for a $15 million payment Select Energy made in December of 2005.

- A benefit of $0.2 million and charges of $0.8 million, respectively, for the three and nine months ended September 30, 2006 related to the fair value of certain asset-specific sales and forward sales of electricity at hub points for generation contracts.

- A benefit of $79.4 million in the first nine months of 2005 comprised of a positive mark-to-market of $100 million in the first half of 2005, partially offset by a charge of $20.6 million in the third quarter of 2005. The $20.6 million charge in the third quarter of 2005 includes approximately $37 million relating to certain wholesale contracts in the PJM power pool where NU Enterprises increased its estimates of customer load above its original expectations and $3.1 million of other charges related to contract assignments. Offsetting these charges is a net pre-tax benefit of $19.5 million associated with the marking-to-market of the supply contracts that previously were held to serve certain retail electric load and other mark-to-market impacts.

Included in the mark-to-market on long-term wholesale electricity contracts is a $44 million and $114.2 million pre-tax mark-to-market charge for the three and nine months ended September 30, 2005, respectively, related to an intercompany contract between Select Energy and CL&P. This contract was included in the portfolio of contracts Select Energy assigned to a third party wholesale power marketer, and Select Energy stopped serving CL&P on December 31, 2005. This contract was part of CL&P's stranded costs, and benefits received by CL&P under this contract were provided to CL&P's ratepayers in the form of lower-than-market standard offer service rates. A $2.8 million pre-tax mark-to-market charge in the first quarter of 2005 was recorded as wholesale contract market changes by Select Energy for the intercompany contract between Select Energy and WMECO for default service from April to June of 2005. There were no wholesale contract market changes in the second or third quarter of 2005, as this contract expired on June 30, 2005. WMECO's benefits under this contract were provided to its ratepayers in the form of lower-than-market default service rates. These charges were not eliminated in consolidation because on a consolidated basis NU retained the over-market obligation to its ratepayers of CL&P and WMECO.

For further information regarding derivative assets and liabilities, see Note 5, "Derivative Instruments."

3.

RESTRUCTURING AND IMPAIRMENT CHARGES (NU, NU Enterprises)

The company evaluates long-lived assets such as property, plant and equipment to determine if these assets are impaired when events or changes in circumstances occur, such as the 2005 announced decisions to exit the NU Enterprises businesses.

When the company believes one of these events has occurred, a determination needs to be made whether a long-lived asset should be classified as an asset to be held and used or whether that asset should be classified as held for sale. For assets classified as held and used, the company estimates the undiscounted future cash flows associated with the long-lived asset or asset group, and an impairment loss is recognized if the carrying amount of an asset is not recoverable. The carrying amount is not recoverable if it exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. For assets held for sale, a long-lived asset or disposal group is measured at the lower of its carrying amount or fair value less cost to sell.

NU Enterprises recorded $10.4 million and $5.3 million of pre-tax restructuring and impairment charges for the three months ended September 30, 2006 and 2005, respectively, and $26 million and $53.2 million for the nine months ended September 30, 2006 and 2005, respectively, related to exiting the merchant energy businesses and the energy services businesses. The amounts related to continuing operations are included as restructuring and impairment charges on the condensed consolidated statements of income/(loss) with the remainder included in discontinued operations. These charges are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." A summary of these pre-tax charges is as follows:

(Millions of Dollars)	For the Three Months Ended September 30, 2006	For the Three Months Ended September 30, 2005	For the Nine Months Ended September 30, 2006	For the Nine Months Ended September 30, 2005
Merchant Energy:				
Wholesale Marketing:				
Restructuring charges	$ 0.1	$ 4.2	$ 0.3	$ 5.2
Retail Marketing:				
Impairment charges	$ -	$ -	$ -	$ 7.2
Restructuring charges	0.6	-	6.4	-
Subtotal	$ 0.6	$ -	$ 6.4	$ 7.2
Competitive Generation:				
Impairment charges	$ -	$ -	$ 0.3	$ -
Restructuring charges	6.8	-	9.5	-
Subtotal	$ 6.8	$ -	$ 9.8	$ -
Subtotal - Merchant Energy	$ 7.5	$ 4.2	$ 16.5	$ 12.4
Energy Services and Other:				
Impairment charges	$ -	$ -	$ 0.1	$ 39.1
Restructuring charges	2.9	1.1	9.4	1.7
Subtotal - Energy Services and Other	$ 2.9	$ 1.1	$ 9.5	$ 40.8
Total restructuring and impairment charges	$ 10.4	$ 5.3	$ 26.0	$ 53.2
Restructuring and impairment charges included in discontinued operations	$ 9.1	$ 0.5	$ 16.3	$ 24.7
Total restructuring and impairment charges included in continuing operations	$ 1.3	$ 4.8	$ 9.7	$ 28.5

For segment reporting purposes, $0.1 million and $0.1 million of wholesale marketing restructuring charges, $0.3 million and $3.2 million of retail marketing restructuring charges and $6.8 million and $9.5 million of competitive generation restructuring charges for the three and nine months ended September 30, 2006, respectively, are included in the NU Enterprises - Services and Other reportable segment, as these amounts were recorded by NU Enterprises parent.

Wholesale Marketing: For the three and nine months ended September 30, 2006, $0.1 million and $0.3 million, respectively, of restructuring charges were recorded in the wholesale marketing segment for consulting fees, legal fees, employee-related and other costs. Similar amounts for the three and nine months ended September 30, 2005 were $4.2 million and $5.2 million, respectively.

Retail Marketing: On June 1, 2006, NU Enterprises completed the sale of Select Energy New York, Inc. (SENY) to Hess Corporation (Hess). In connection with the closing of this transaction, NU Enterprises recorded restructuring charges in the second quarter of $0.3 million in the retail marketing segment, which is included in restructuring and impairment charges on the accompanying condensed consolidated statements of income/(loss) for the nine months ended September 30, 2006. In addition to the $0.3 million charge, restructuring charges of $0.6 million and $6.1 million, respectively, were recorded for the three and nine months ended September 30, 2006, respectively, for consulting fees, legal fees, employee-related costs and other costs. There were no restructuring charges for the three and nine months ended September 30, 2005.

In the first quarter of 2005, an exclusivity agreement intangible asset included in the retail marketing segment totaling $7.2 million was written off.

Competitive Generation: In the second quarter of 2006, $0.3 million of impairments were recorded in the competitive generation segment related to certain long lived assets of Northeast Generation Services Company (NGS) that were no longer recoverable. Additional restructuring charges of $6.8 million and $9.5 million, respectively, were recorded for the three and nine months ended September 30, 2006 for consulting fees, legal fees, sale-related environmental fees, employee-related and other costs. There were no restructuring charges related to competitive generation for the three and nine months ended September 30, 2005.

Energy Services and Other: On May 5, 2006, NU Enterprises completed the sale of SESI to Ameresco, Inc. (Ameresco). In connection with the closing of this transaction, NU Enterprises paid Ameresco approximately $7.7 million and recorded a pre-tax restructuring charge of $6.5 million. In the third quarter of 2006, an additional restructuring charge of $1.6 million was recorded related to additional charges incurred for the sale of SESI to Ameresco. These charges are included in loss from sale of discontinued operations on the accompanying condensed consolidated statements of income/(loss).

For the three and nine months ended September 30, 2006, restructuring charges included $0.3 million and $2 million in charges related to consulting fees, legal fees, employee-related costs, and other costs and $1 million of charges related to NU's guarantee of SESI's performance under government contracts. These guarantee-related charges represent estimated purchase and refinancing costs for two projects' contract payments. See Note 7F, "Commitments and Contingencies - Guarantees and Indemnifications," for further information.

Offsetting the charges for the first nine month of 2006 is a benefit of $1.7 million from the gain on the sale of Massachusetts service location of Select Energy Contracting, Inc. - Connecticut (SECI-CT) recorded in the first quarter of 2006.

The amounts described above are included in the Services and Other reportable segment. See Note 12, "Segment Information," for further information.

In 2005, the company concluded that $29.1 million of goodwill associated with the energy services businesses and $9.2 million of intangible assets were impaired as of March 31, 2005. In the second quarter of 2005, the energy services businesses and NU Enterprises parent recorded an additional impairment charge of $0.8 million due to the impairment of certain fixed assets resulting in a total impairment charge of $39.1 million for the first half of 2005, included in the Energy Services and Other segment.

For the three and nine months ended September 30, 2005, restructuring costs totaling $1.1 million and $1.7 million were recorded for the energy services business related to professional fees, employee-related and other costs.

The following table summarizes the liabilities related to restructuring costs which are recorded in accounts payable and other current liabilities on the accompanying condensed consolidated balance sheets at September 30, 2006 and December 31, 2005:

(Millions of Dollars)	**Employee - Related Costs**	**Professional and Other Fees**	**Net (Gain)/ Loss on Sale**	**Total**
Restructuring liability as of January 1, 2005	$ -	$ -	$ -	$ -
Costs incurred	2.3	7.4	-	9.7
Cash payments and other deductions	(0.5)	(2.1)	-	(2.6)

Restructuring liability as of December 31, 2005	$ 1.8	$ 5.3	$ -	$ 7.1
Costs incurred/gain on sale	0.3	6.5	(0.7)	6.1
Cash payments and other deductions	(0.3)	(4.6)	0.7	(4.2)
Restructuring liability as of March 31, 2006	$ 1.8	$ 7.2	$ -	$ 9.0
Costs incurred/loss on sale	2.0	1.2	5.9	9.1
Cash payments and other deductions	(0.6)	(3.4)	(5.9)	(9.9)
Restructuring liability as of June 30, 2006	$ 3.2	$ 5.0	$ -	$ 8.2
Costs incurred/loss on sale	0.6	8.2	1.6	10.4
Cash payments and other deductions	(0.1)	(11.6)	-	(11.7)
Restructuring liability as of September 30, 2006	$ 3.7	$ 1.6	$ 1.6	$ 6.9

In addition to the $0.6 million of retail marketing severance costs included in restructuring charges above, $3.7 million of other retail marketing severance costs and other employee benefits were recorded in other operating expenses on the accompanying condensed consolidated statements of income/(loss) for the nine months ended September 30, 2006 because these amounts are for severance under an existing benefit arrangement. For further information, see Note 11, "Pension Benefits and Postretirement Benefits Other Than Pensions."

4.

ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS (NU, NU Enterprises)

A summary of the NU Enterprises businesses held for sale status as of September 30, 2006 and December 31, 2005, as well as the discontinued operations status for all periods presented including date sold, is as follows:

	Held for Sale Status as of			
	September 30, 2006	**December 31, 2005**	**Discontinued Operations**	**Sale Date**
Wholesale Marketing	No	No	No	Not Sold
Retail Marketing	Sold	No	No	June 2006
NGC (including certain components of NGS)	Yes	No	Yes	November 2006
Mt. Tom	Yes	No	Yes	November 2006
SESI	Sold	Yes	Yes	May 2006
Woods Electrical - non-industrial division	Sold	Yes	Yes	April 2006
Woods Electrical - industrial division	No	No	No	Not Sold
SECI-NH	Sold	Sold	Yes	November 2005
Woods Network	Sold	Sold	Yes	November 2005
E.S. Boulos Company	No	No	No	Not Sold
SECI-CT	No	No	No	Not Sold

Assets Held for Sale: In November of 2005, NU decided to exit NU Enterprises' retail marketing and competitive generation businesses. At December 31, 2005, management determined that the wholesale and retail marketing businesses did not meet the held for sale criteria under applicable accounting guidance.

In the first quarter of 2006, management determined that the retail marketing and competitive generation businesses met held for sale criteria under applicable accounting guidance, and should therefore be recorded at the lower of carrying amount or fair value less cost to sell. The retail marketing business was reduced to its fair value less cost to sell in the first half of 2006 through a $53.9 million pre-tax charge, which was recorded in other operating expenses. On July 24, 2006, NU reached an agreement with various affiliates of Energy Capital Partners (ECP) to sell its 100 percent ownership in NGC and HWP's 146 megawatt (MW) Mt. Tom coal-fired plant. The competitive generation assets remain carried at their historical carrying value, which is less than their fair value less cost to sell. For further information see Note 13, "Subsequent Events."

At September 30, 2006, management continues to believe the wholesale marketing business, E.S. Boulos Company (Boulos), and SECI-CT do not meet the held for sale criteria under applicable accounting guidance and therefore continue to be held and used and included in continuing operations.

Remaining contracts not yet assigned but subject to back-to-back agreements of Select Energy's retail marketing business that will be assigned or transferred to Hess are recorded at fair value less cost to sell and are included in assets held for sale and liabilities of assets held for sale.

The businesses above are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." The major classes of assets and liabilities that are held for sale at September 30, 2006 and December 31, 2005 are as follows (amounts at December 31, 2005 are not comparable to amounts at September 30, 2006 as the assets held for sale portfolio has changed):

(Millions of Dollars)	**At September 30, 2006**		**At December 31, 2005**	
Property, plant and equipment	$	838.3	$	-
Derivative contracts		0.9		-
Long-term contract receivables		-		79.5
Other assets		22.7		22.3
Total assets		861.9		101.8
Long-term debt		318.3		86.3
Derivative contracts		5.5		-
Other liabilities		25.3		15.2
Total liabilities		349.1		101.5
Net assets	$	512.8	$	0.3

Discontinued Operations: NU's condensed consolidated statements of income/(loss) for all periods presented classify NGC and Mt. Tom in discontinued operations. SESI and a portion of Woods Electrical are included in discontinued operations for the nine months ended September 30, 2006 and for the three and nine months ended September 30, 2005. These businesses were sold in May and April of 2006, respectively. In addition, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the three and nine months ended September 30, 2005, as these businesses were sold in November of 2005.

Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified net of tax in income from discontinued operations on the condensed consolidated statements of income/(loss), and all prior periods have been reclassified. These businesses are included as part of the NU Enterprises reportable segment in Note 12, "Segment Information." Summarized financial information for the discontinued operations is as follows:

	For the Three Months Ended		For the Nine Months Ended	
	September 30, 2006	**September 30, 2005**	**September 30, 2006**	**September 30, 2005**
Operating revenue	$ 46.4	$ 77.6	$ 157.6	$ 249.2
Income before income tax expense	15.9	8.9	54.8	20.4
Income tax expense	5.5	3.7	19.4	8.9
Net income	8.8	5.2	27.3	11.5

Included in discontinued operations are $46.3 million and $144.6 million for the three and nine months ended September 30, 2006, respectively, and $50 million and $163.4 million for the three and nine ended September 30, 2005, respectively, of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of these amounts, $46.3 million and $144.4 million for the three and nine months ended September 30, 2006, respectively, and $48.3 million and $153.3 million for the three and nine months ended September 30, 2005, respectively, represent revenues on intercompany contracts between the generation operations of NGC and Mt. Tom and Select Energy. NGC's and Mt. Tom's revenues and earnings related to these contracts are included in discontinued operations while Select Energy's related expenses and losses are included in continuing operations. Included in the net income from discontinued operations is a pre-tax $5.8 million related to the resolution of contingencies for businesses sold.

At September 30, 2006, NU does not expect that after disposal it will have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations. In addition, the intercompany contracts between the generation operations of NGC and Mt. Tom and Select Energy will be terminated at time of sale.

The retail marketing business is not presented as discontinued operations because separate financial information is not available for this business for periods prior to the first quarter of 2006.

5.

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

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchases or normal sales 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 changes in the fair value of the effective portion of those contracts are generally recognized in accumulated other comprehensive income. Cash flow hedges impact net income when the forecasted transaction being hedged occurs, when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is no longer probable of occurring, or when there is accumulated other comprehensive loss and the hedge and the forecasted transaction being hedged are in a loss position on a combined basis. The ineffective portion of contracts that meet the cash flow hedge requirements is recognized currently in earnings. 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 currently 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 change in fair value of a normal purchase or sale contract is not included in earnings.

The tables below summarize current and long-term derivative assets and liabilities at September 30, 2006 and December 31, 2005. At September 30, 2006 and December 31, 2005, derivative assets and liabilities of NU Enterprises have been segregated between wholesale, retail and generation amounts. The fair value of these contracts may not represent amounts that will be realized.

	At September 30, 2006				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises:					
Wholesale	$ 58.2	$ 26.3	$ (116.4)	$ (114.4)	$ (146.3)
Retail	0.9	-	(2.6)	(0.3)	(2.0)
Generation	4.1	-	(3.9)	(2.5)	(2.3)
Utility Group - Gas:					
Non-trading	0.1	-	(0.3)	-	(0.2)
Utility Group - Electric:					
Non-trading	42.2	248.0	(6.0)	(32.3)	251.9
NU Parent:					
Hedging	-	-	-	(6.5)	(6.5)
	105.5	274.3	(129.2)	(156.0)	94.6
Derivative assets and liabilities held for sale	0.9	-	(2.7)	(2.8)	(4.6)
Totals	$ 104.6	$ 274.3	$ (126.5)	$ (153.2)	$ 99.2

	At December 31, 2005				
	Assets		Liabilities		
	Current	Long-Term	Current	Long-Term	Net Totals
(Millions of Dollars)					
NU Enterprises:					
Wholesale	$ 256.6	$ 103.5	$ (369.3)	$ (220.9)	$ (230.1)
Retail	55.0	12.9	(27.2)	0.4	41.1
Generation	9.2	-	(5.1)	(15.5)	(11.4)
Utility Group - Gas:					
Non-trading	0.1	-	(0.4)	-	(0.3)

Utility Group - Electric:					
Non-trading	82.6	308.6	(0.5)	(31.8)	358.9
NU Parent:					
Hedging	-	-	-	(5.2)	(5.2)
Totals	$ 403.5	$ 425.0	$ (402.5)	$ (273.0)	$ 153.0

The business activities of NU Enterprises that result in the recognition of derivative assets result in exposures to credit risk to energy marketing and trading counterparties. At September 30, 2006 and December 31, 2005, Select Energy had derivative assets from wholesale, retail and generation activities that are exposed to counterparty credit risk. However, a significant portion of these assets is contracted with investment grade rated counterparties or collateralized with cash.

NU Enterprises - Wholesale: Certain electricity and natural gas derivative contracts are part of Select Energy's wholesale marketing business that the company is in the process of exiting. These contracts include wholesale short-term and long-term electricity supply and sales contracts, which include contracts to sell electricity to utilities under full requirements contracts, a contract to sell electricity to a municipality with a term of seven remaining years, and two contracts to purchase the output of generating plants. The fair value of electricity contracts was determined by prices from external sources for years through 2010 and by models based on natural gas prices and a heat-rate conversion factor to electricity for subsequent periods.

Derivatives used in wholesale activities are recorded at fair value and included in the condensed consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recorded in the period of change, mostly in wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss).

NU Enterprises - Retail: On June 1, 2006, Select Energy closed on the sale of its retail marketing business to Hess, and the related derivative assets and liabilities were transferred to Hess, except in cases where a customer has not yet consented to assignment. These remaining retail derivative assets and liabilities are recorded at fair value on the accompanying condensed consolidated balance sheet, which is determined using information from available external sources. At September 30, 2006, Select Energy had no derivatives under hedge accounting. As of September 30, 2006, Select Energy had derivative assets and liabilities totaling $0.9 million and $2.9

million, respectively, related to back-to-back agreements for electric and gas sourcing contracts for which Select Energy has not yet received consent from the customers or suppliers to assign the contracts to Hess.

At December 31, 2005, Select Energy maintained natural gas service agreements with certain retail customers to supply gas at fixed prices for terms extending through 2010. New York Mercantile Exchange (NYMEX) futures contracts acquired to meet these commitments were recorded at fair value as derivative assets totaling $8.2 million and derivative liabilities of $0.3 million. Select Energy also maintained various financial instruments to hedge its electric and gas purchases and sales which included forwards, futures and swaps. At December 31, 2005, these hedging contracts, which were valued at the mid-point of bid and ask market prices, were recorded as derivative assets of $24.4 million and derivative liabilities of $4.8 million. These amounts were zero at September 30, 2006 because the contracts expired or were assigned to Hess.

Select Energy hedged certain amounts of natural gas inventory with gas futures that were accounted for as fair value hedges. Changes in the fair value of hedging instruments and natural gas inventory were recorded in fuel, purchased, and net interchange power. The change in fair value of the futures were included in derivative liabilities and amounted to $3.4 million at December 31, 2005. These amounts were zero at September 30, 2006 because the contracts expired or were assigned to Hess.

NU Enterprises - Generation: Derivative contracts include generation asset-specific sales and forward sales of electricity at hub trading points. The fair value of these contracts was determined by prices from external sources for the period of the contracts. Certain of these short-term forward purchase and sales contracts have been recorded at fair value in revenues since inception. They represent market transactions at liquid points, while other generation-asset-specific sales and forward sales of electricity qualified for accrual accounting until the fourth quarter of 2005 when Select Energy marked them to market because the probability of physical delivery and the normal election could no longer be asserted. Changes in fair value of generation contracts formerly accounted for on an accrual basis are recorded in wholesale contract market changes, net for those contracts that are part of continuing operations. Changes in fair value of generation contracts that are held for sale are included in discontinued operations. These contracts extend through 2008.

Utility Group - Gas - Non-Trading: Yankee Gas's non-trading 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 purchase and sales because of the optionality in the contract terms. Non-trading derivatives at September 30, 2006 included assets of $0.1 million and liabilities of $0.3 million. At December 31, 2005, non-trading derivatives included assets of $0.1 million and liabilities of $0.4 million.

Utility Group - Electric - Non-Trading: CL&P has contracts with two independent power producers (IPP) 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 IPP non-trading derivatives at September 30, 2006 include a derivative asset with a fair value of $290.2 million and a derivative liability with a fair value of $35.7 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of the stranded costs, and management believes that these costs will continue to be recovered or refunded in cost of service, regulated rates. At December 31, 2005, the fair values of these IPP non-trading derivatives included a derivative asset with a fair value of $391.2 million and a derivative liability with a fair value of $32.3 million.

CL&P has entered into Financial Transmission Rights (FTR) contracts to limit the congestion costs associated with its transitional standard offer (TSO) contracts. An offsetting regulatory asset has been recorded as this contract is part of the stranded costs, and management believes that these costs will be recovered in rates. At September 30, 2006, the fair value of these contracts is recorded as a derivative liability of $2.6 million on the accompanying condensed consolidated balance sheets. The fair value of CL&P's FTRs at December 31, 2005 was equal to the value when acquired as there were no changes in fair value of the FTRs through December 31, 2005.

NU Parent - Hedging: In March of 2003, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate note that matures on April 1, 2012. The changes in fair value of the swap and the hedged debt instrument are recorded on the condensed consolidated balance sheets and are equal and offsetting in the condensed consolidated statements of income/(loss). The cumulative change in the fair value of the hedged debt of $6.5 million is included as a decrease to long-term debt on the condensed consolidated balance sheets. The hedge is recorded as a derivative liability of $6.5 million at September 30, 2006, and $5.2 million at December 31, 2005. The resulting changes in interest payments made are recorded as adjustments to interest expense.

6.

GOODWILL AND OTHER INTANGIBLE ASSETS (Yankee Gas, NU Enterprises)

The only NU reporting unit that currently maintains goodwill is the Yankee Gas reporting unit, which is classified under the Utility Group - gas reportable segment. The goodwill recorded related to the acquisition of Yankee Gas is not being recovered from the customers of Yankee Gas. The goodwill balance was $287.6 million at both September 30, 2006 and December 31, 2005. The company is currently in the process of performing the annual impairment test of the Yankee Gas goodwill for impairment.

As a result of NU's 2005 announcements to exit all of NU Enterprises' businesses, certain goodwill balances and intangible assets were deemed to be impaired. During the nine months ended September 30, 2005, goodwill and intangible asset balances at the NU Enterprises energy services businesses were determined to be impaired, and $38.3 million in write-offs were recorded. In addition, $7.2 million of intangible assets, related to an exclusivity agreement held by the retail marketing business, were written off.

NU recorded amortization expense of $0.3 million and $1.4 million for the three and nine months ended September 30, 2005, respectively, related to intangible assets subject to amortization.

7.

COMMITMENTS AND CONTINGENCIES

A.

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

Connecticut:

Income Taxes: In 2000, CL&P requested from the Internal Revenue Service (IRS) a private letter ruling (PLR) regarding the treatment of unamortized investment tax credits (UITC) and excess investment tax credits (EDIT) related to generation assets that were sold. On April 18, 2006, the IRS issued a PLR to CL&P regarding the treatment of UITC and EDIT. EDIT are temporary differences between book and taxable income that were recorded when the federal statutory tax rate was higher than it is now or when those differences were expected to be resolved. The PLR holds that it would be a violation of tax regulations if the EDIT or UITC is used to reduce customers' rates following the sale of the generation assets. CL&P's UITC and EDIT balances related to generation assets that have been sold totaled $59 million and $15 million, respectively, and $74 million combined. CL&P was ordered by the DPUC to submit the PLR to the DPUC within 10 days of issuance and retain the UITC and EDIT in their existing accounts pending its receipt and review of the PLR. On July 27, 2006, the DPUC determined that the UITC and EDIT amounts were no longer required to be held in their existing accounts. As a result of this determination, the $74 million balance was reflected as a reduction to CL&P's third quarter 2006 income tax expense with an increase to CL&P's earnings by the same amount.

Purchased Gas Adjustment: On September 9, 2005, the DPUC issued a draft decision regarding Yankee Gas Purchased Gas Adjustment (PGA) clause charges for the period of September 1, 2003 through August 31, 2004. The draft decision disallowed approximately $9 million in previously recovered PGA revenues associated with two separate Yankee Gas unbilled sales and revenue adjustments. At the request of Yankee Gas, the DPUC reopened the PGA hearings on September 20, 2005 and requested that Yankee Gas file supplemental information regarding the two adjustments. Yankee Gas complied with this request. The DPUC issued a new decision on April 20, 2006 requiring an audit of Yankee Gas' PGA accounting methods and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. In a recent draft decision regarding Yankee Gas PGA charges for the period September 1, 2004 through August 31, 2005, an additional $2 million related to previously recovered revenues was also identified, bringing the total maximum amount at issue with regard to PGA clause charges under audit to $11 million.

The DPUC has hired a consulting firm who has begun an audit of Yankee Gas' PGA accounting methods. The company expects that the audit will be completed by the end of 2006. Management believes the unbilled sales and revenue adjustments and resultant charges to customers through the PGA clause for both periods were appropriate. Based on the facts of the case and the supplemental information provided to the DPUC, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved, and has not reserved for any loss.

New Hampshire:

SCRC Reconciliation: On May 1, 2006, PSNH filed its 2005 SCRC reconciliation with the New Hampshire Public Utilities Commission (NHPUC). On October 25, 2006, PSNH, the NHPUC staff and the Office of Consumer Advocate (OCA) filed a settlement agreement with the NHPUC which resolved all outstanding issues associated with the 2005 SCRC reconciliation. Management believes that this settlement agreement will not have a material effect on PSNH's financial statements. The NHPUC held hearings on October 26, 2006, and currently management does not have a specific date when the NHPUC's order will be issued.

Coal Procurement Docket: During the second quarter of 2006, the NHPUC opened a docket to review PSNH's coal procurement and coal transportation policies and procedures. PSNH is responding to data requests from the NHPUC's outside consultant. While management believes its coal procurement and transportation policies and procedures are prudent and consistent with industry practice, it is unable to determine the impact, if any, of the NHPUC's review on PSNH's earnings or financial position.

Northern Wood Power Project: Construction of the conversion of PSNH's 50-MW coal-fired unit at Schiller Station in Portsmouth, New Hampshire to burn wood (Northern Wood Power Project) started in 2004. The new boiler is operating under coal and/or wood at various times as part of its start-up compliance adjustment and testing, with testing expected to be completed by the end of 2006. Under the terms of the order issued by the NHPUC approving the project, the costs of the project are subject to a prudence review by the NHPUC and the cost of the project was capped at $75 million. In the event the project's cost exceeds the $75 million cap, PSNH and its customers would each absorb half of the costs in excess of $75 million. While management currently believes that the project's cost will not exceed the $75 million cap and that PSNH's actions during the construction of the project have been prudent and consistent with industry practices, PSNH is unable to determine the impact, if any, of the NHPUC's prudence review of the project on PSNH's earnings or financial position.

Massachusetts:

Transition Cost Reconciliation: On October 24, 2006, the Massachusetts Department of Telecommunications and Energy (DTE) issued its decision in WMECO's 2003 and 2004 transition cost reconciliation filing. The DTE decision in this combined docket resolves all outstanding issues through 2004 for transition, retail transmission, standard offer and default service costs/revenues and did not have a significant impact on WMECO's earnings or financial position.

WMECO filed its 2005 transition cost reconciliation with DTE on March 31, 2006. The DTE has not yet reviewed this filing or issued a schedule for review and the timing of a decision is uncertain. Management does not expect the outcome of the DTE's review to have a significant adverse impact on WMECO's earnings or financial position.

B.

NRG Energy, Inc. Exposures (CL&P, Yankee Gas)

Certain subsidiaries of NU, including CL&P and Yankee Gas, entered into transactions with NRG Energy, Inc. (NRG) and certain of its subsidiaries. On May 14, 2003, NRG and certain subsidiaries of NRG filed voluntary bankruptcy petitions, and on December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions relate to 1) the refunding of approximately $30 million of congestion charges previously withheld from NRG prior to the implementation of standard market design on March 1, 2003, which is still pending before the court, 2) the recovery of approximately $23.8 million of CL&P's station service billings from NRG, which is currently the subject of an arbitration, and 3) the recovery of, among other claimed damages, approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased. While it is unable to determine the ultimate outcome of these issues, management does not expect their resolution will have a material adverse effect on NU's consolidated earnings or financial position.

C.

Long-Term Contractual Arrangements (CL&P, Merchant Energy)

CL&P: These amounts represent commitments for various services and materials associated primarily with the Bethel, Connecticut to Norwalk, Connecticut, the Middletown, Connecticut to Norwalk, and the Norwalk to Northport-Long Island, New York transmission projects as of September 30, 2006.

(Millions of Dollars)	2006	2007	2008	2009	2010	Thereafter	Total
Transmission business							
project commitments	$168.2	$238.3	$150.7	$9.7	$2.9	$ -	$569.8

Yankee Companies FERC-Approved Billings, Subject to Refund: NU has significant decommissioning and plant closure cost obligations to the Yankee Companies. Each plant has been shut down and is undergoing decommissioning. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including NU's electric utility companies. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. In the third quarter of 2006, the decommissioning periods for YAEC and CYAPC were extended to 2014 and 2015, respectively. As a result, the amounts for the future obligations have changed. The table below includes the estimated decommissioning and closure costs for YAEC, MYAPC and CYAPC:

(Millions of Dollars)	2006	2007	2008	2009	2010	Thereafter	Total
FERC-approved billings	$19.0	$43.4	$35.1	$28.4	$31.7	$132.4	$290.0

PSNH Electricity Procurement Obligations: PSNH has entered into various arrangements for the purchase of electricity. These amounts relate to IPP obligations that PSNH entered into pursuant to rate orders issued by the NHPUC and do not include PSNH's short-term power supply management. The future amounts under these obligations are as follows:

(Millions of Dollars)	2006	2007	2008	2009	2010	Thereafter	Total
Electricity procurement obligations	$28.6	$73.0	$38.9	$32.2	$32.5	$248.0	$453.2

Merchant Energy: Select Energy maintains long-term agreements to purchase energy as part of its portfolio of resources to meet its actual or expected sales commitments. The majority of these purchase commitments are being actively marketed. Certain purchase commitments are accounted for on the accrual basis, while the remaining commitments are recorded at their mark-to-market value. These purchase commitments at September 30, 2006 are as follows:

(Millions of Dollars)	2006	2007	2008	2009	2010	Thereafter	Total
Select Energy purchase commitments	$442.0	$613.6	$193.2	$29.7	$32.1	$46.0	$1,356.6

Select Energy's purchase commitment amounts exceed the amount expected to be reported in fuel, purchased and net interchange power because many wholesale sales transactions are also classified in fuel, purchased and net interchange power, and certain purchases are included in revenues. Select Energy also maintains certain wholesale, retail and generation energy commitments whose mark-to-market values have been recorded on the condensed consolidated balance sheets as derivative assets and liabilities, a portion of which is included in assets held for sale and liabilities of assets held for sale. These contracts are included in the table above.

The amounts and timing of the costs associated with Select Energy's purchase agreements will be impacted by the exit from the NU Enterprises' businesses.

D.

Deferred Contractual Obligations (NU, CL&P, PSNH, WMECO)

CYAPC: On July 1, 2004, CYAPC filed with the FERC for recovery seeking to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection by CYAPC beginning on February 1, 2005, subject to refund.

On June 10, 2004, the DPUC and the Connecticut Office of Consumer Counsel (OCC) filed a petition with the FERC seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. The FERC rejected the DPUC's and OCC's petition, whereupon the DPUC filed an appeal of the FERC's decision with the D.C. Circuit Court of Appeals (Court of Appeals).

On August 15, 2006, CYAPC, the DPUC, the OCC and Maine state regulators filed a settlement agreement with the FERC. The settlement agreement, if approved, disposes of the pending litigation at the FERC and the Court of Appeals, among other issues.

Under the terms of the settlement agreement, the parties have agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars), taking into account actual spending through 2005 and the current estimate for completing decommissioning and long-term storage of spent fuel, a gross domestic product escalator of 2.5 percent for costs incurred after 2006, and a 10 percent contingency factor for all decommissioning costs. Annual collections at the revised level would begin in 2007, and are reduced from the $93 million originally requested for years 2007 through 2010. Revised annual collections begin at $37 million in 2007 and reach $46 million in 2015.

The reduction to annual collections is achieved by extending the collection period by 5 years through 2015, reflecting the proceeds from a settlement agreement with Bechtel Power Corporation (Bechtel) by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. Additionally, the settlement agreement includes an incentive that reduces collections up to $10 million during years 2007 to 2010, but allows CYAPC to recoup up to $5 million of these collections, depending on the date that the Nuclear Regulatory Commission amends CYAPC's license permitting fuel storage-only operations. The settlement agreement also contains various mechanisms for true-ups and adjustments related to decommissioning and allows CYAPC to resume reasonable payment of dividends to its shareholders. The FERC staff has filed in support of the settlement agreement and no party has objected to the settlement agreement. Management expects that the FERC will rule on the settlement agreement by the end of 2006.

The settlement agreement also required CYAPC to forego collection of a $10 million regulatory asset and write this amount off. Because the contingency surrounding this regulatory asset existed at June 30, 2006, the write-off was recorded in the second quarter.

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NU recorded a total after-tax write-off of $3 million ($2.1 million, $0.3 million and $0.6 million for CL&P, PSNH and WMECO, respectively) for its 49 percent ownership share of this charge.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal no later than January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In 2004, a trial was conducted in the Court of Federal Claims in which 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 Yankee Companies had claimed actual damages for the same period as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed wet pool operating expenses. The Court of Federal Claims found that Yankee Companies would have incurred the disallowed expenses notwithstanding the DOE breach given the DOE's probable rate of acceptance of spent nuclear fuel had a depository been available.

The Court of Federal Claims, following precedent set in another case, also did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. The Yankee Companies believe they will have the opportunity in future lawsuits to seek recovery of actual damages incurred in the years following 2001/2002. The Yankee Companies expect the DOE to appeal the decision. 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 collectively own 49 percent of CYAPC, 38.5 percent of YAEC and 20 percent of MYAPC, and their aggregate share of these damages would be $44.7 million. Their respective shares of these damages would be as follows: CL&P: $29 million; PSNH: $7.8 million; and WMECO: $7.9 million. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery or the credit to future storage costs that may be realized in connection with this matter.

E.

Consolidated Edison, Inc. Merger Litigation

Certain gain and loss contingencies exist with regard to the merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation.

On March 5, 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the parties' 1999 merger agreement (Merger Agreement). On March 12, 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In an opinion dated October 12, 2005, a panel of three judges at the Second Circuit held that the shareholders of NU had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. NU's request for a rehearing was denied on January 3, 2006. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of "at least $314 million." NU opted not to seek review of this ruling by the United States Supreme Court. On April 7, 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to judgment in its favor with respect to this claim based on the undisputed material facts and applicable law. The matter is fully briefed and awaiting a decision. At this stage, NU cannot predict the outcome of this matter or its ultimate effect on NU.

F.

Guarantees and Indemnifications

NU provides credit assurances on behalf of subsidiaries in the form of guarantees and letters of credit (LOCs) in the normal course of business. In addition, NU has provided guarantees and various indemnifications on behalf of external parties as a result of the second quarter sales of SESI to Ameresco and the retail marketing business to Hess. The following table summarizes NU's maximum exposure at September 30, 2006, 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	Performance guarantees under government contracts.	$79.1	2019 - 2026 (1)	$ -
	General indemnifications in connection with the sale of SESI including environmental issues, general product claims, compliance with laws, and other claims.	Not Specified (2)	None	-
	Specific indemnification in connection with the sale of SESI for payment of shortfalls in the event of early termination of government contracts.	1.4	2008	-
	Specific indemnifications in connection with the sale of SESI for estimated costs to complete or modify specific projects above specified levels.	Not Specified (2)	Through project completion	0.2
Hess (Retail Marketing)	Performance guarantee for retail marketing contracts assigned to Hess for the sale of energy.	1.1	2006	-
	General indemnifications in connection with the sale including compliance with laws, validity of contract information, absence of default on contracts, and other claims.	Not Specified (2)	None	-

Subsidiary	Description	Maximum Exposure (in millions)	Expiration Date(s)	Fair Value of Amounts Recorded (in millions)
On behalf of subsidiaries:				
Utility Group	Surety bonds	$11.0	None	N/A
	Letters of credit	45.5	2006 - 2007	N/A
Rocky River Realty Company	Lease payments	11.7	2024	N/A
Energy Services Businesses	Performance and payment guarantees	73.0	2006 - 2007	N/A
Northeast Generation Company	Debt obligations	14.1	2026 (3)	N/A
Northeast Generation Services	Performance and payment guarantees	2.1	2006 - 2007	N/A
Select Energy	Performance guarantees for retail marketing contracts not yet assigned to Hess.	16.6 (4)	2006 - None (5)	N/A
	Performance guarantees for wholesale marketing contracts.	275.2 (4)	None	N/A
	Letters of credit	32.0	2006	N/A

(1)

As of September 30, 2006, NU guaranteed SESI's performance under five government contracts financed by one investor. In the third quarter of 2006, NU gave notice that it would not renew these guarantees. On October 27, 2006, NU closed on a settlement agreement with the investor and paid approximately $1 million to eliminate its obligations under the guarantees. This amount was recorded in the third quarter. In connection with the settlement agreement, NU indemnified SESI's new lender for payment shortfalls in the event of early termination of two government contracts. The maximum exposure under this indemnification is $1.6 million and decreases monthly through 2020.

On July 7, 2006, the investor notified SESI that pursuant to financing terms it would require SESI to repurchase contract payments relating to the only guaranteed project that was behind schedule. SESI did not satisfy this requirement and on July 26, 2006, the contract payments were assigned to NU and NU paid the investor $10.4 million, $0.6 million of which was also recorded as a pre-tax third quarter loss related to the refinancing of the project. In addition, NU recorded a $0.2 million pre-tax loss to reflect the fair value of this guarantee in the second quarter of 2006. Upon SESI's completion of the project, NU expects to sell the contract payments to SESI through financing from SESI's committed lender. NU may record additional losses associated with this transaction, the amount of which will depend on changes in interest rates used to determine SESI's refinancing proceeds, the amount of project cash available to offset NU's costs, and other factors.

(2)

There is no specified maximum exposure included in the related sale agreements. The estimated maximum exposure on the specific indemnifications associated with the SESI sale is $1.1 million. Hess may not assert an indemnification claim based on unintentional data errors unless and until damages exceed a $5 million aggregate threshold, at which point Hess may assert a claim for all damages. All other claims are subject to a $0.3 million threshold.

(3)

The guarantee was terminated upon the sale of NGC on November 1, 2006.

(4)

Maximum exposure is as of September 30, 2006; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

(5)

NU is working with counterparties to terminate these guarantees as the retail marketing contracts are assigned to Hess and does not currently anticipate that these guarantees on behalf of Select Energy will result in significant guarantees of the performance of Hess.

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

8.

MARKETABLE SECURITIES

The following is a summary of NU's available-for-sale securities related to NU's Supplemental Executive Retirement Plan (SERP) assets, WMECO's prior spent nuclear fuel trust assets and NU's investment in Globix Corporation (Globix), which are recorded at their fair values and are included in current and long-term marketable securities on the accompanying condensed consolidated balance sheets. Changes in the fair value of these securities are recorded as unrealized gains and losses in accumulated other comprehensive income:

(Millions of Dollars)	**At September 30, 2006**	**At December 31, 2005**
SERP assets	$ 61.1	$ 58.1
WMECO prior spent nuclear fuel trust assets	52.6	50.8
Globix investment	-	3.7
Totals	$ 113.7	$ 112.6

NU had an investment in the common stock of NEON Communications, Inc. (NEON), a provider of optical networking services. On March 8, 2005, NEON merged with Globix. In connection with the closing of the merger, a $0.1 million after-tax loss was recognized in the first quarter of 2005 and a pre-tax positive $0.4 million change in fair value subsequent to March 8, 2005 was included in accumulated other comprehensive income. On April 6, 2006, NU sold its investment in Globix. This sale resulted in net proceeds of $6.7 million and a pre-tax gain of $3.1 million.

At September 30, 2006 and December 31, 2005, marketable securities are comprised of the following:

	At September 30, 2006			
(Millions of Dollars)	**Amortized Cost**	**Pre-Tax Gross Unrealized Gains**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**
United States equity securities	$ 20.3	$ 4.6	$ (0.3)	$ 24.6
Non-United States equity securities	5.7	1.6	-	7.3
Fixed income securities	82.1	0.3	(0.6)	81.8
Totals	$ 108.1	$ 6.5	$ (0.9)	$ 113.7

	At December 31, 2005			
(Millions of Dollars)	**Amortized Cost**	**Pre-Tax Gross Unrealized Gains**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**
United States equity securities	$ 23.2	$ 3.9	$ (0.3)	$ 26.8
Non-United States equity securities	6.3	0.9	-	7.2

Fixed income securities		79.3		0.2		(0.9)		78.6
Totals	$	108.8	$	5.0	$	(1.2)	$	112.6

At September 30, 2006 and December 31, 2005, NU evaluated the securities in an unrealized loss position and has determined that none of the related unrealized losses are deemed to be other-than-temporary in nature. At September 30, 2006 and December 31, 2005, the gross unrealized losses and fair value of NU's investments that have been in a continuous unrealized loss position for less than 12 months and 12 months or greater were as follows:

	Less than 12 Months		**12 Months or Greater**		**Total**	
(Millions of Dollars) **At September 30, 2006**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**
United States equity securities	$ 3.0	$ (0.3)	$ 0.1	$ (0.1)	$ 3.1	$ (0.4)
Fixed income securities	26.5	(0.4)	4.8	(0.1)	31.3	(0.5)
Totals	$ 29.5	$ (0.7)	$ 4.9	$ (0.2)	$ 34.4	$ (0.9)

	Less than 12 Months		**12 Months or Greater**		**Total**	
(Millions of Dollars) **At December 31, 2005**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**	**Estimated Fair Value**	**Pre-Tax Gross Unrealized Losses**
United States equity securities	$ 2.9	$ (0.2)	$ 0.4	$ (0.1)	$ 3.3	$ (0.3)
Fixed income securities	39.8	(0.7)	5.7	(0.2)	45.5	(0.9)
Totals	$ 42.7	$ (0.9)	$ 6.1	$ (0.3)	$ 48.8	$ (1.2)

For information related to the change in net unrealized holding gains and losses included in shareholders' equity, see Note 9, "Comprehensive Income," to the condensed consolidated financial statements.

For the three and nine months ended September 30, 2006 and 2005, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

(Millions of Dollars)	Three Months Ended September 30, Realized Gains	Realized Losses	Net Realized Gains/(Losses)	Nine Months Ended September 30, Realized Gains	Realized Losses	Net Realized Gains/(Losses)
2006	$ 0.3	$ (0.5)	$ (0.2)	$ 1.1	$ (1.1)	$ -
2005	$ 0.2	$ (0.3)	$ (0.1)	$ 0.8	$ (0.5)	$ 0.3

Net realized losses of $0.1 million and gains of $0.4 million for the three and nine months ended September 30, 2006, respectively, and gains of $0.1 million and $0.5 million for the three and nine months ended September 30, 2005, respectively, are included in other income, net on the accompanying condensed consolidated statements of income/(loss). Net realized losses of $0.1 million and $0.4 million for the three and nine months ended September 30, 2006, respectively, and $0.2 million and $0.2 million for the three and nine months ended September 30, 2005, respectively, relating to the WMECO spent nuclear fuel trust are included in fuel, purchased and net interchange power on the accompanying condensed consolidated statements of income/(loss).

NU utilizes the specific identification basis method for the SERP securities and the average cost basis method for the WMECO prior spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $42.3 million and $127 million for the three and nine months ended September 30, 2006, respectively. Of these amounts, $6.7 million relates to the proceeds from the sale of NU's investment in Globix. These amounts totaled $41.9 million and $96.5 million for the three and nine months ended September 30, 2005, respectively.

At September 30, 2006, the contractual maturities of the available-for-sale securities are as follows:

(Millions of Dollars)	Amortized Cost	Estimated Fair Value
Less than one year	$ 30.6	$ 30.3
One to five years	26.6	26.5
Six to ten years	6.7	6.6
Greater than ten years	18.6	18.4
Subtotal	82.5	81.8
Equity securities	25.6	31.9
Total	$ 108.1	$ 113.7

9.

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

Total comprehensive income, which includes all comprehensive income/(loss) items by category, for the three and nine months ended September 30, 2006 and 2005 is as follows:

	Three Months Ended September 30, 2006						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net income/(loss)	$ 111.5	$ 99.6	$ 7.9	$ 3.7	$ 3.2	$ (5.3)	$ 2.4
Comprehensive income/(loss) items:							
Unrealized gains/(losses) on securities	(0.9)	-	(0.1)	(0.1)	-	-	(0.7)
Net change in comprehensive income items	(0.9)	-	(0.1)	(0.1)	-	-	(0.7)
Total comprehensive income/(loss)	$ 110.6	$ 99.6	$ 7.8	$ 3.6	$ 3.2	$ (5.3)	$ 1.7

	Three Months Ended September 30, 2005						
(Millions of Dollars)	NU*	CL&P	PSNH	WMECO	NU Enterprises	Yankee Gas	Other
Net (loss)/income	$ (94.5)	$ 26.1	$ 12.0	$ 4.8	$ (129.6)	$ (4.2)	$ (3.6)
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	17.0	-	-	1.0	15.7	0.2	0.1
Unrealized gains/(losses) on securities	-	-	-	0.1	(0.9)	-	0.8
Net change in comprehensive income items	17.0	-	-	1.1	14.8	0.2	0.9

Total comprehensive (loss)/income	$ (77.5)	$ 26.1	$ 12.0	$ 5.9	$ (114.8)	$ (4.0)	$ (2.7)

	Nine Months Ended September 30, 2006						
(Millions of Dollars)	**NU***	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**Other**
Net income/(loss)	$ 123.6	$ 148.2	$ 27.9	$ 11.5	$ (73.7)	$ 6.4	$ 3.3
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	13.2	(4.6)	-	0.1	17.8	-	(0.1)
Unrealized losses on securities	(1.0)	-	(0.1)	(0.2)	-	-	(0.7)
Other	2.3	-	-	-	-	-	2.3
Net change in comprehensive income items	14.5	(4.6)	(0.1)	(0.1)	17.8	-	1.5
Total comprehensive income/(loss)	$ 138.1	$ 143.6	$ 27.8	$ 11.4	$ (55.9)	$ 6.4	$ 4.8

	Nine Months Ended September 30, 2005						
(Millions of Dollars)	**NU***	**CL&P**	**PSNH**	**WMECO**	**NU Enterprises**	**Yankee Gas**	**Other**
Net (loss)/income	$ (239.9)	$ 62.3	$ 29.8	$ 11.9	$ (344.1)	$ 10.3	$ (10.1)
Comprehensive income/(loss) items:							
Qualified cash flow hedging instruments	22.4	-	-	1.0	22.1	(0.8)	0.1
Unrealized losses on securities	(3.1)	-	-	(0.2)	(2.8)	-	(0.1)
Net change in comprehensive income items	19.3	-	-	0.8	19.3	(0.8)	-
Total comprehensive (loss)/income	$ (220.6)	$ 62.3	$ 29.8	$ 12.7	$ (324.8)	$ 9.5	$ (10.1)

*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 cash flow hedging instruments for the nine months ended September 30, 2006 and the twelve months ended December 31, 2005 are as follows:

(Millions of Dollars, Net of Tax)	**Nine Months Ended September 30, 2006**	**Twelve Months Ended December 31, 2005**
Balance at beginning of period	$ 18.2	$ (3.5)
Hedged transactions recognized into earnings	1.4	5.6
Amount reclassified into earnings due to discontinuation of cash flow hedges	(14.1)	-
Change in fair value	(1.7)	11.0
Cash flow transactions entered into for the period	1.2	5.1
Net change associated with the current period hedging transactions	(13.2)	21.7
Total fair value adjustments included in accumulated other comprehensive income	$ 5.0	$ 18.2

For the nine months ended September 30, 2006, $1.3 million, net of tax, was reclassified from accumulated other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized into earnings in revenues and fuel, purchased, and net interchange power and $0.1 million was reclassified into earnings related to the amortization of interest rate hedges. In the first quarter of 2006, $14.1 million was reclassified from accumulated other comprehensive income into earnings (specifically included in other operation expenses) due to discontinuing cash flow hedge accounting and concluding that the retail marketing contracts hedged beyond June 1, 2006 were no longer probable of physical delivery due to the retail business being sold.

In March of 2006, CL&P entered into a forward lock agreement to hedge the interest rate associated with $125 million of its planned $250 million, 30-year fixed rate debt issuance. Under the agreement, CL&P locked in a LIBOR swap rate of 5.322 percent based on the notional amount of $125 million in debt that was issued in June of 2006. On June 1, 2006, the hedged transaction was settled and as a result $4.6 million, net of tax ($7.8 million pre-tax), which was previously recorded in accumulated other comprehensive income to be amortized into earnings over the life of the debt.

At September 30, 2006, it is estimated that $45 thousand included in the accumulated other comprehensive income balance will be reclassified as an increase to earnings in the next year.

Accumulated other comprehensive income items unrelated to NU's cash flow hedging instruments totaled $0.5 million of losses and $1.8 million of gains at September 30, 2006 and December 31, 2005, respectively. These amounts relate to unrealized gains on investments in marketable debt and equity securities and minimum pension liability adjustments, net of related income taxes.

10.

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. Dilutive shares in the following table excludes 1,224,834 options for the three months ended September 30, 2005, and 152,050 options and 1,224,834 options for the nine months ended September 30, 2006 and 2005, as these options were antidilutive. The weighted average common shares outstanding at September 30, 2006 include the impact of the issuance of 23 million common shares on December 12, 2005. 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)	**2006**	**2005**	**2006**	**2005**
Income/(loss) from continuing operations	$ 102.7	$ (99.7)	$ 96.3	$ (251.4)
Income from discontinued operations	8.8	5.2	27.3	11.5
Net income/(loss)	111.5	(94.5)	123.6	(239.9)
Basic EPS common shares outstanding (average)	153,883,480	129,957,408	153,651,610	129,585,519
Dilutive effect	437,195	-	385,160	-
Fully diluted EPS common shares outstanding (average)	154,320,675	129,957,408	154,036,770	129,585,519
Basic and Fully Diluted EPS:				
Income/(loss) from continuing operations	0.67	(0.77)	0.63	(1.94)
Income from discontinued operations	0.05	0.04	0.17	0.09
Basic and fully diluted EPS	$ 0.72	$ (0.73)	$ 0.80	$ (1.85)

11.

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 (PBOP Plan). The components of net periodic benefit expense for the Pension Plan and the PBOP Plan for the three and nine months ended September 30, 2006 and 2005 are estimated as follows:

NU	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
(Millions of Dollars)								
Service cost	$ 12.4	$ 12.1	$ 2.1	$ 2.2	$ 37.0	$ 36.4	$ 6.2	$ 6.0
Interest cost	33.1	31.3	6.8	6.3	96.6	94.0	20.5	18.9
Expected return on plan assets	(43.8)	(42.9)	(3.5)	(3.3)	(130.2)	(128.8)	(10.5)	(8.9)
Amortization of unrecognized net transition (asset)/obligation	-	-	3.1	2.9	(0.1)	(0.2)	8.6	8.9
Amortization of prior service cost	1.8	1.8	(0.1)	(0.1)	4.8	5.3	(0.2)	(0.3)
Amortization of actuarial loss	10.9	8.3	-	-	30.3	24.8	-	-
Other amortization, net	-	-	4.4	4.6	-	-	13.4	13.2
Net periodic expense - before								

curtailments and termination benefits	14.4	10.6	12.8	12.6	38.4	31.5	38.0	37.8
Curtailment income	(4.2)	-	(1.5)	-	(4.9)	-	(2.1)	-
Termination benefit (income)/expense	(0.7)	-	(0.2)	-	-	-	0.3	-
Total curtailments and termination benefits	(4.9)	-	(1.7)	-	(4.9)	-	(1.8)	-
Total - net periodic expense	$ 9.5	$ 10.6	$ 11.1	$ 12.6	$ 33.5	$ 31.5	$ 36.2	$ 37.8

A portion of these pension amounts is capitalized related to current employees that are working on capital projects. Amounts capitalized were approximately $7.7 million and $12.9 million for the three and nine months ended September 30, 2006, respectively, and $2.3 million and $7 million for the three and nine months ended September 30, 2005, respectively.

CL&P	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
(Millions of Dollars)								
Service cost	$ 4.2	$ 4.3	$ 0.7	$ 0.7	$ 12.8	$ 12.8	$ 2.1	$ 2.1
Interest cost	12.1	11.7	2.8	2.6	35.9	35.0	8.3	7.7
Expected return on plan assets	(20.4)	(20.0)	(1.4)	(1.3)	(61.0)	(59.9)	(4.1)	(3.5)
Amortization of unrecognized net transition obligation	-	-	1.7	1.6	-	-	4.6	4.7
Amortization of prior service cost	0.8	0.7	-	-	2.0	2.2	-	-
Amortization of actuarial loss	4.1	3.1	-	-	11.9	9.4	-	-
Other amortization, net	-	-	1.7	1.8	-	-	5.3	5.3
Net periodic expense - before curtailments termination benefits	0.8	(0.2)	5.5	5.4	1.6	(0.5)	16.2	16.3

Curtailment income	(1.0)	-	(0.8)	-	(1.3)	-	(1.4)	-
Termination benefit income	(0.4)	-	-	-	(0.8)	-	(0.1)	-
Total curtailments and termination benefits	(1.4)	-	(0.8)	-	(2.1)	-	(1.5)	-
Total - net periodic (income)/expense	$ (0.6)	$ (0.2)	$ 4.7	$ 5.4	$ (0.5)	$ (0.5)	$ 14.7	$ 16.3

Not included in the pension and postretirement benefits expense amounts above are intercompany allocations totaling $2.7 million and $1.7 million, respectively, for the three months ended September 30, 2006 and $2 million and $1.9 million, respectively, for the three months ended September 30, 2005. Amounts for pension and postretirement benefits totaled $8.8 million and $5.6 million, respectively, for the nine months ended September 30, 2006 and $6.1 million and $5.4 million, respectively, for the nine months ended September 30, 2005.

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 $3 million and $4.4 million for the three and nine months ended September 30, 2006, respectively, and $0.7 million and $2.1 million for the three and nine months ended September 30, 2005, respectively.

PSNH	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
(Millions of Dollars)								
Service cost	$ 2.4	$ 2.2	$ 0.5	$ 0.4	$ 7.2	$ 6.6	$ 1.3	$ 1.2
Interest cost	5.2	4.8	1.2	1.1	15.2	14.4	3.7	3.3
Expected return on plan assets	(4.2)	(4.1)	(0.6)	(0.5)	(12.3)	(12.4)	(1.9)	(1.5)
Amortization of unrecognized net transition obligation	0.1	0.1	0.6	0.6	0.2	0.3	1.9	1.9
Amortization of prior service cost	0.4	0.3	-	-	1.0	1.1	-	-
Amortization of actuarial loss	1.7	1.2	-	-	4.6	3.6	-	-
Other amortization, net	-	-	0.8	0.8	-	-	2.5	2.2
Net periodic expense - before termination benefits	5.6	4.5	2.5	2.4	15.9	13.6	7.5	7.1
Curtailment (income)/expense	(0.7)	-	(0.1)	-	(0.6)	-	0.1	-
Termination benefit income	(0.1)	-	-	-	-	-	-	-
Total curtailment and termination benefits	(0.8)	-	(0.1)	-	(0.6)	-	0.1	-
Total - net periodic expense	$ 4.8	$ 4.5	$ 2.4	$ 2.4	$ 15.3	$ 13.6	$ 7.6	$ 7.1

Not included in the pension and postretirement benefits expense amounts above are intercompany allocations totaling $0.4 million and $0.3 million, respectively, for the three months ended September 30, 2006 and $0.5 million and $0.4 million, respectively, for the three months ended September 30, 2005. Amounts for pension and postretirement benefits totaled $1.3 million and $1 million, respectively, for the nine months ended September 30, 2006 and $1.4 million and $1 million, respectively, for the nine months ended September 30, 2005.

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 $3.9 million and $7.3 million for the three and nine months ended September 30, 2006, respectively, and $1.3 million and $3.9 million for the three and nine months ended September 30, 2005, respectively.

WMECO	**For the Three Months Ended September 30,**				**For the Nine Months Ended September 30,**			
	Pension Benefits		**Postretirement Benefits**		**Pension Benefits**		**Postretirement Benefits**	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
(Millions of Dollars)								
Service cost	$ 0.8	$ 0.8	$ 0.1	$ 0.2	$ 2.6	$ 2.5	$ 0.5	$ 0.5
Interest cost	2.4	2.3	0.6	0.5	7.2	7.0	1.8	1.6
Expected return on plan assets	(4.4)	(4.3)	(0.4)	(0.3)	(13.4)	(13.0)	(1.1)	(0.9)
Amortization of unrecognized net transition obligation	-	-	0.4	0.3	-	-	1.0	1.0
Amortization of prior service cost	0.2	0.2	-	-	0.5	0.5	-	-
Amortization of actuarial loss	0.8	0.6	-	-	2.4	1.8	-	-
Other amortization, net	-	-	0.4	0.4	-	-	1.1	1.0
Net periodic expense - before termination benefits	(0.2)	(0.4)	1.1	1.1	(0.7)	(1.2)	3.3	3.2
Curtailment income	(0.2)	-	(0.1)	-	(0.2)	-	(0.3)	-
Termination benefit income	(0.1)	-	-	-	(0.2)	-	-	-
Total curtailment and termination benefits	(0.3)	-	(0.1)	-	(0.4)	-	(0.3)	-
Total - net periodic (income)/expense	$ (0.5)	$ (0.4)	$ 1.0	$ 1.1	$ (1.1)	$ (1.2)	$ 3.0	$ 3.2

Not included in the pension income and postretirement benefits expense amounts above are intercompany allocations totaling $0.6 million and $0.3 million, respectively, for the three months ended September 30, 2006 and $0.4 million and $0.3 million, respectively, for the three months ended September 30, 2005. Amounts for pension and postretirement benefits totaled $1.6 million and $0.9 million, respectively, for the nine months ended September 30, 2006 and $1.2 million and $1 million, respectively, for the nine months ended September 30, 2005.

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 $0.2 million and $0.1 million for the three and nine months ended September 30, 2006, respectively, and $0.1 million for nine months ended September 30, 2005. A de minimus amount was capitalized during the three months ended September 30, 2005. The capitalized amounts for 2005 offset capital project costs, as pension income was recorded for those periods.

NU does not currently expect to make any contributions to the Pension Plan in 2006. NU contributed and anticipates contributing approximately $12.4 million quarterly totaling approximately $50 million in 2006 to fund its PBOP Plan.

Curtailment and Termination Benefits Adjustments: In December of 2005, a new program was approved providing a benefit for certain employees hired on and after January 1, 2006 allowing these employees to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. The approval of the new plan resulted in the recording of an estimated pre-capitalization, pre-tax curtailment expense of $6.2 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Management estimated the amount of the curtailment expense associated with this change based upon actuarial calculations and certain assumptions, including the expected level of transfers to the new 401(k) benefit. Because the predicted level of elections of the new benefit did not occur, NU recorded an adjustment to this curtailment in the third quarter of 2006. This adjustment resulted in a pre-capitalization, pre-tax reduction in the curtailment expense of $3.6 million.

In addition, as a result of its corporate reorganization, NU recorded a combined pre-capitalization, pre-tax curtailment expense and related termination benefits for the Pension Plan totaling $5.5 million in 2005. Based on a revised estimate of expected head count reductions, NU recorded an adjustment to the curtailment and related termination benefits in the first nine months of 2006. This adjustment resulted in a combined pre-capitalization, pre-tax reduction in the curtailment expense and termination benefits of $1.3 million.

Severance Benefits: As a result of its corporate reorganization, in 2005 NU recorded severance and termination benefits totaling $14.4 million relating to expected terminations of Utility Group and NUSCO employees. These severance benefits were recorded in other operating expenses because these amounts were for severance benefits under an existing benefit arrangement. In the second and third quarters of 2006, NU updated its prior estimates of Utility Group and NUSCO severance benefits based upon actual termination data and updated its estimates of expected head count reductions. A total reduction in severance and related expenses of $2.4 million was recorded and is included in other operating expenses on the accompanying condensed consolidated statements of income/(loss) for the nine months ended September 30, 2006, primarily due to a reduction in the expected number of terminated Utility Group and NUSCO employees.

Severance benefits for employees in the retail marketing and competitive generation businesses were not recorded in 2005 or in the first quarter of 2006 as management expected to sell these businesses as going concerns with the employees being transferred to the buyers. In the first nine months of 2006, NU recorded $4.1 million for severance and other employee benefits, as these benefits became probable and estimable as a result of the sale of the retail marketing business to Hess. Of this amount, $0.6 million was for enhanced minimum benefits and was included in restructuring charges, with the remaining $3.5 million included in other operating expenses on the accompanying condensed consolidated statements of income/(loss) for the nine months ended September 30, 2006 because these amounts were for severance benefits under an existing benefit arrangement.

12.

SEGMENT INFORMATION (All Companies)

Presentation: NU is organized between the Utility Group 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 operates. Effective on January 1, 2005, the portion of NGS's business that supports NGC's and HWP's generation assets has been reclassified from the services and other segment to the merchant energy segment within the NU Enterprises segment. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include 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.

Effective in the first quarter of 2006, separate financial information was prepared and used by management for each of the NU Enterprises merchant energy businesses it is exiting. Accordingly, separate detailed information is presented below for the wholesale and retail marketing and competitive generation businesses for the three and nine months ended September 30, 2006. It is not practicable to prepare comparable detailed information for any periods prior to the first quarter of 2006 due to the manner in which the merchant energy business operated prior to the first quarter of 2006.

The Utility Group segment, including the regulated electric, distribution, generation and transmission businesses, as well as the gas distribution business comprised of Yankee Gas, represents approximately 95 percent and 85 percent for the three and nine months ended September 30, 2006, respectively, and 81 percent and 74 percent for the three and nine months ended September 30, 2005, respectively, of NU's total revenues and includes the operations of the regulated electric utilities, CL&P, PSNH and WMECO, whose complete condensed consolidated financial statements (net of eliminations) are included in this combined report on Form 10-Q. PSNH's distribution segment includes generation activities. Also included in this combined report on Form 10-Q is detailed information regarding CL&P's, PSNH's, and WMECO's transmission businesses. Utility Group revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

The NU Enterprises merchant energy business segment includes: 1) Select Energy, consisting of the wholesale and retail marketing businesses; and 2) NGC, NGS, and Mt. Tom, collectively referred to as the competitive generation business. The NU Enterprises services and other business segment includes E. S. Boulos Company, Woods Electrical, and NGS Mechanical, Inc., (which are subsidiaries of NGS), SESI, SECI, HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC, and intercompany eliminations between the energy services businesses and merchant energy businesses. The results of NU Enterprises parent are also included within services and other.

Other in the tables includes the results for Mode 1, the results of the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, Yankee Energy Financial Services Company, and NorConn Properties, Inc.), the non-generation operations of HWP, and the results of NU's parent and service companies. Interest expense included in other primarily relates to the debt of NU parent.

Intercompany Transactions: Total Select Energy revenues from CL&P represented $0.7 million and $4.5 million for the three and nine months ended September 30, 2006, respectively, and $14.3 million and $41 million for the three and nine months ended September 30, 2005, respectively, of total NU Enterprises' revenues. Total Select Energy revenues from CL&P related to nontraditional standard offer contracts are eliminated in consolidation.

Total Select Energy revenues from transactions with WMECO represented $0.1 million and $0.6 million of total NU Enterprises' revenues for the three and nine months ended September 30, 2006, respectively, and $2.1 million and $35.9 million for the three and nine months ended September 30, 2005, respectively. Total Select Energy revenues from WMECO are eliminated in consolidation.

Select Energy purchases from NGC and Mt. Tom represented $46.3 million and $144.4 million for the three and nine months ended September 30, 2006, respectively. These amounts totaled $48.3 million and $153.3 million for NGC and Mt. Tom for the three and nine months ended September 30, 2005, respectively.

Customer Concentrations: Select Energy revenues related to contracts with NSTAR companies represented $6 million and $294.6 million of total NU Enterprises' revenues for the three and nine months ended September 30, 2005, respectively. There were no sales to NSTAR for the three and nine months ended September 30, 2006. Select Energy also provides basic generation service in the New Jersey and Maryland markets. Select Energy revenues related to these contracts represented $96.1 million and $346.6 million for the three and nine months ended September 30, 2006, respectively, and $84.8 million and $228 million for the three and nine months ended September 30, 2005, respectively. Select Energy revenues from Constellation Energy Commodities Group, Inc., represented $5.9 million and $45.3 million for three and nine months ended September 30, 2006 and $124.9 million and $282.2 million for the three and nine months ended September 30, 2005. No other individual customer represented in excess of 10 percent of NU Enterprises' revenues for the three and nine months ended September 30, 2006 and 2005.

Select Energy reported the settlement of all derivative contracts of the wholesale business, including full requirements sales contracts and intercompany revenues, in fuel, purchased and net interchange power. This presentation is a result of applying mark-to-market accounting to those contracts due to the decision to exit the wholesale marketing business.

NU's segment information for the three and nine months ended September 30, 2006 and 2005 is as follows (some amounts between the financial statements and between segment schedules may not agree due to rounding):

	For the Three Months Ended September 30, 2006						
	Utility Group						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,397.3	$ 62.6	$ 58.0	$ 80.4	$ 91.8	$ (96.0)	$ 1,594.1
Depreciation and amortization	(87.1)	(5.7)	(7.6)	(0.1)	(4.8)	3.6	(101.7)
Wholesale contract market changes, net	-	-	-	4.8	-	-	4.8
Restructuring and impairment charges	-	-	-	(1.3)	-	-	(1.3)
Other operating expenses	(1,242.0)	(61.4)	(23.9)	(98.6)	(84.9)	92.2	(1,418.6)
Operating income/(loss)	68.2	(4.5)	26.5	(14.8)	2.1	(0.2)	77.3
Interest expense, net of AFUDC	(41.4)	(4.2)	(6.5)	(5.3)	(9.7)	4.3	(62.8)
Interest income	1.7	-	0.1	0.4	5.6	(6.1)	1.7
Other income/(loss), net	8.1	0.1	1.8	-	18.8	(16.6)	12.2
Income tax (expense)/benefit	57.5	3.3	(3.4)	14.1	4.8	(0.6)	75.7
Preferred dividends	(1.1)	-	(0.3)	-	-	-	(1.4)
Income/(loss) from continuing operations	$ 93.0	$ (5.3)	$ 18.2	$ (5.6)	$ 21.6	$ (19.2)	$ 102.7
Income/(loss) from discontinued operations	-	-	-	8.8	-	-	8.8
Net income/(loss)	$ 93.0	$ (5.3)	$ 18.2	$ 3.2	$ 21.6	$ (19.2)	$ 111.5

	For the Nine Months Ended September 30, 2006						
	Utility Group						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 4,082.5	$ 335.1	$ 155.2	$ 854.0	$ 263.6	$ (287.9)	$ 5,402.5
Depreciation and amortization	(327.3)	(17.0)	(22.0)	(0.5)	(14.0)	10.5	(370.3)
Wholesale contract market changes, net	-	-	-	(14.9)	-	-	(14.9)
Restructuring and impairment charges	-	-	-	(9.7)	-	-	(9.7)
Other operating expenses	(3,531.6)	(297.0)	(66.8)	(981.4)	(246.5)	276.9	(4,846.4)
Operating income/(loss)	223.6	21.1	66.4	(152.5)	3.1	(0.5)	161.2
Interest expense, net of AFUDC	(127.0)	(12.7)	(16.0)	(22.7)	(28.5)	19.1	(187.8)
Interest income	7.1	-	0.2	4.0	20.1	(21.6)	9.8
Other income/(loss), net	20.5	0.3	4.4	0.2	106.5	(99.7)	32.2
Income tax (expense)/benefit	23.1	(2.3)	(10.5)	70.0	6.5	(1.7)	85.1
Preferred dividends	(3.3)	-	(0.9)	-	-	-	(4.2)
Income/(loss) from continuing operations	$ 144.0	$ 6.4	$ 43.6	$ (101.0)	$ 107.7	$ (104.4)	$ 96.3
Income/(loss) from discontinued operations	-	-	-	27.3	-	-	27.3
Net income/(loss)	$ 144.0	$ 6.4	$ 43.6	$ (73.7)	$ 107.7	$ (104.4)	$ 123.6
Total Assets (2)	$ 8,898.4	$ 1,189.0	$ -	$ 1,295.1	$ 4,627.2	$ (4,517.2)	$ 11,492.5
Cash flows for total investments in plant	$ 217.9	$ 62.3	$ 285.2	$ 17.2	$ 17.7	$ -	$ 600.3

	For the Three Months Ended September 30, 2005						
	Utility Group						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 1,321.4	$ 59.9	$ 42.8	$ 338.2	$ 84.9	$ (92.3)	$ 1,754.9
Depreciation and amortization	(168.8)	(5.6)	(6.1)	(0.5)	(4.5)	3.5	(182.0)
Wholesale contract market changes, net	-	-	-	(101.2)	-	-	(101.2)
Restructuring and impairment charges	-	-	-	(4.8)	-	-	(4.8)
Other operating expenses	(1,071.0)	(45.8)	(20.9)	(410.4)	(91.6)	87.1	(1,552.6)
Operating income/(loss)	81.6	8.5	15.8	(178.7)	(11.2)	(1.7)	(85.7)
Interest expense, net of AFUDC	(41.7)	(4.3)	(3.9)	(3.8)	(9.0)	3.4	(59.3)
Interest income	1.2	0.1	0.1	0.8	3.5	(4.3)	1.4
Other income/(loss), net	7.6	-	2.3	(0.5)	16.0	(15.0)	10.4
Income tax (expense)/benefit	(16.6)	(8.5)	(2.1)	47.4	14.8	(0.1)	34.9
Preferred dividends	(1.0)	-	(0.4)	-	-	-	(1.4)
Income/(loss) from continuing operations	$ 31.1	$ (4.2)	$ 11.8	$ (134.8)	$ 14.1	$ (17.7)	$ (99.7)
Income/(loss) from discontinued operations	-	-	-	5.2	-	-	5.2
Net income/(loss)	$ 31.1	$ (4.2)	$ 11.8	$ (129.6)	$ 14.1	$ (17.7)	$ (94.5)

For the Nine Months Ended September 30, 2005

(Millions of Dollars)	Utility Group Distribution (1) Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$ 3,602.1	$ 343.1	$ 124.7	$ 1,512.9	$ 253.5	$ (316.8)	$ 5,519.5
Depreciation and amortization	(386.4)	(16.5)	(17.6)	(2.6)	(13.2)	10.1	(426.2)
Wholesale contract market changes, net	-	-	-	(359.7)	-	-	(359.7)
Restructuring and impairment charges	-	-	-	(28.5)	-	-	(28.5)
Other operating expenses	(2,993.2)	(300.4)	(57.4)	(1,644.4)	(239.7)	302.0	(4,933.1)
Operating income/(loss)	222.5	26.2	49.7	(522.3)	0.6	(4.7)	(228.0)
Interest expense, net of AFUDC	(129.4)	(12.7)	(11.3)	(11.2)	(25.3)	11.0	(178.9)
Interest income	3.0	0.3	0.4	3.0	11.6	(13.5)	4.8
Other income/(loss), net	17.4	(0.2)	3.9	(0.9)	89.6	(86.6)	23.2
Income tax (expense)/benefit	(36.9)	(3.3)	(11.1)	175.8	7.1	0.1	131.7
Preferred dividends	(3.1)	-	(1.1)	-	-	-	(4.2)
Income/(loss) from continuing operations	$ 73.5	$ 10.3	$ 30.5	$ (355.6)	$ 83.6	$ (93.7)	$ (251.4)
Loss from discontinued operations	-	-	-	11.5	-	-	11.5
Net income/(loss)	$ 73.5	$ 10.3	$ 30.5	$ (344.1)	$ 83.6	$ (93.7)	$ (239.9)
Total assets (2)	$ 8,645.3	$ 1,117.8	$ -	$ 3,097.3	$ 4,225.2	$ (4,156.2)	$ 12,929.4
Cash flows for total investments in plant	$ 287.1	$ 46.6	$ 166.2	$ 13.4	$ 8.2	$ -	$ 521.5

(1)

Includes PSNH's generation activities.

(2)

Information for segmenting total assets between electric distribution and transmission is not available at September 30, 2006. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution column above.

Utility Group segment information related to the regulated electric distribution and transmission businesses for CL&P, PSNH and WMECO for the three and nine months ended September 30, 2006 and 2005 is as follows:

	CL& P - For the Three Months Ended September 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 1,040.5	$ 42.8	$ 1,083.3
Depreciation and amortization	(63.9)	(5.7)	(69.6)
Other operating expenses	(941.2)	(16.8)	(958.0)
Operating income	35.4	20.3	55.7
Interest expense, net of AFUDC	(26.6)	(5.2)	(31.8)
Interest income	1.1	0.1	1.2
Other income/(loss), net	7.1	1.8	8.9
Income tax benefit/(expense)	68.5	(1.5)	67.0
Preferred dividends	(1.1)	(0.3)	(1.4)
Net income	$ 84.4	$ 15.2	$ 99.6

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	CL& P - For the Nine Months Ended September 30, 2006		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 2,918.1	$ 109.7	$ 3,027.8
Depreciation and amortization	(183.9)	(16.3)	(200.2)
Other operating expenses	(2,615.2)	(45.7)	(2,660.9)
Operating income	119.0	47.7	166.7
Interest expense, net of AFUDC	(82.3)	(12.2)	(94.5)
Interest income	5.6	0.2	5.8
Other income/(loss), net	17.7	4.1	21.8
Income tax expense	57.4	(4.9)	52.5
Preferred dividends	(3.2)	(0.9)	(4.1)
Net income	$ 114.2	$ 34.0	$ 148.2
Cash flows for total investments in plant	$ 129.6	$ 258.8	$ 388.4

	CL& P - For the Three Months Ended September 30, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 923.4	$ 29.0	$ 952.4
Depreciation and amortization	(83.6)	(4.4)	(88.0)
Other operating expenses	(790.9)	(13.7)	(804.6)
Operating income	48.9	10.9	59.8
Interest expense, net of AFUDC	(26.6)	(3.0)	(29.6)
Interest income	0.9	0.1	1.0
Other income/(loss), net	7.0	2.0	9.0
Income tax expense	(12.3)	(0.4)	(12.7)
Preferred dividends	(1.0)	(0.4)	(1.4)
Net income	$ 16.9	$ 9.2	$ 26.1

	CL&P - For the Nine Months Ended September 30, 2005		
(Millions of Dollars)	**Distribution**	**Transmission**	**Totals**
Operating revenues	$ 2,505.3	$ 83.6	$ 2,588.9

Depreciation and amortization		(204.0)		(13.1)		(217.1)
Other operating expenses		(2,169.1)		(37.4)		(2,206.5)
Operating income		132.2		33.1		165.3
Interest expense, net of AFUDC		(83.7)		(8.8)		(92.5)
Interest income		2.4		0.4		2.8
Other income/(loss), net		15.8		3.6		19.4
Income tax expense		(22.7)		(5.8)		(28.5)
Preferred dividends		(3.1)		(1.1)		(4.2)
Net income	$	40.9	$	21.4	$	62.3
Cash flows for total investments in plant	$	171.1	$	137.9	$	309.0

	PSNH - For the Three Months Ended September 30, 2006					
(Millions of Dollars)	**Distribution (1)**		**Transmission**		**Totals**	
Operating revenues	$	256.6	$	10.5	$	267.1
Depreciation and amortization		(18.2)		(1.3)		(19.5)
Other operating expenses		(214.5)		(4.7)		(219.2)
Operating income		23.9		4.5		28.4
Interest expense, net of AFUDC		(10.5)		(0.9)		(11.4)
Interest income		0.2		-		0.2
Other income/(loss), net		0.7		-		0.7
Income tax expense		(8.5)		(1.5)		(10.0)
Net income	$	5.8	$	2.1	$	7.9

	PSNH - For the Nine Months Ended September 30, 2006		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$ 845.8	$ 31.2	$ 877.0
Depreciation and amortization	(130.4)	(3.9)	(134.3)
Other operating expenses	(638.0)	(14.3)	(652.3)
Operating income	77.4	13.0	90.4
Interest expense, net of AFUDC	(31.9)	(2.5)	(34.4)
Interest income	0.9	-	0.9
Other income/(loss), net	1.7	0.3	2.0
Income tax expense	(26.9)	(4.1)	(31.0)
Net income	$ 21.2	$ 6.7	$ 27.9
Cash flows for total investments in plant	$ 65.0	$ 16.9	$ 81.9

	PSNH - For the Three Months Ended September 30, 2005		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$ 298.0	$ 9.3	$ 307.3
Depreciation and amortization	(78.8)	(1.1)	(79.9)
Other operating expenses	(197.0)	(4.9)	(201.9)
Operating income	22.2	3.3	25.5
Interest expense, net of AFUDC	(10.8)	(0.6)	(11.4)
Interest income	0.2	-	0.2
Income tax expense	(1.1)	(1.2)	(2.3)
Net income	$ 10.5	$ 1.5	$ 12.0

	PSNH - For the Nine Months Ended September 30, 2005		
(Millions of Dollars)	**Distribution (1)**	**Transmission**	**Totals**
Operating revenues	$ 808.6	$ 27.2	$ 835.8
Depreciation and amortization	(166.1)	(3.2)	(169.3)
Other operating expenses	(579.6)	(13.2)	(592.8)
Operating income	62.9	10.8	73.7
Interest expense, net of AFUDC	(32.9)	(1.7)	(34.6)
Interest income	0.4	0.1	0.5
Other loss, net	0.4	0.1	0.5
Income tax expense	(6.8)	(3.5)	(10.3)

Net income	$	24.0	$	5.8	$	29.8
Cash flows for total investments in plant	$	101.9	$	22.6	$	124.5

(1)

Includes PSNH's generation activities.

	WMECO - For the Three Months Ended September 30, 2006					
(Millions of Dollars)	**Distribution**		**Transmission**		**Totals**	
Operating revenues	$	100.3	$	4.7	$	105.0
Depreciation and amortization		(5.0)		(0.6)		(5.6)
Other operating expenses		(86.4)		(2.4)		(88.8)
Operating income		8.9		1.7		10.6
Interest expense, net of AFUDC		(4.2)		(0.4)		(4.6)
Interest income		0.3		-		0.3
Other income, net		0.3		-		0.3
Income tax expense		(2.5)		(0.4)		(2.9)
Net income	$	2.8	$	0.9	$	3.7

	WMECO - For the Nine Months Ended September 30, 2006		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 318.7	$ 14.3	$ 333.0
Depreciation and amortization	(12.9)	(1.8)	(14.7)
Other operating expenses	(278.5)	(6.9)	(285.4)
Operating income	27.3	5.6	32.9
Interest expense, net of AFUDC	(12.8)	(1.3)	(14.1)
Interest income	0.6	0.1	0.7
Other income, net	0.9	-	0.9
Income tax expense	(7.4)	(1.5)	(8.9)
Net income	8.6	2.9	11.5
Cash flows for total investments in plant	$ 23.2	$ 9.1	$ 32.3

	WMECO - For the Three Months Ended September 30, 2005		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 100.0	$ 4.6	$ 104.6
Depreciation and amortization	(6.5)	(0.5)	(7.0)
Other operating expenses	(83.3)	(2.2)	(85.5)
Operating income	10.2	1.9	12.1
Interest expense, net of AFUDC	(4.3)	(0.3)	(4.6)
Interest income	0.2	-	0.2
Other income, net	0.7	-	0.7
Income tax expense	(3.1)	(0.5)	(3.6)
Net income	$ 3.7	$ 1.1	$ 4.8

	WMECO - For the Nine Months Ended September 30, 2005		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 288.4	$ 13.9	$ 302.3
Depreciation and amortization	(16.3)	(1.4)	(17.7)
Other operating expenses	(244.7)	(6.6)	(251.3)
Operating income	27.4	5.9	33.3
Interest expense, net of AFUDC	(12.8)	(0.8)	(13.6)
Interest income	0.2	-	0.2
Other income, net	1.2	-	1.2

Income tax expense		(7.4)		(1.8)		(9.2)
Net income	$	8.6	$	3.3	$	11.9
Cash flows for total investments in plant	$	22.8	$	8.0	$	30.8

NU Enterprises' segment information for the three and nine months ended September 30, 2006 and 2005 is as follows. The services and other column includes eliminations relating to the total merchant energy business and the energy services businesses.

	NU Enterprises	For the Three Months Ended September 30, 2006				
(Millions of Dollars)	Wholesale	Retail	Generation	Total Merchant Energy	Services and Other	Totals
Operating revenues	$ (7.9)	$ 5.8	$ 73.3	$ 71.2	$ 9.2	$ 80.4
Depreciation and amortization	-	-	-	-	(0.1)	(0.1)
Wholesale contract market changes, net	4.6	-	0.2	4.8	-	4.8
Restructuring and impairment charges	-	(0.3)	-	(0.3)	(1.0)	(1.3)
Other operating expenses	(2.4)	1.4	(83.7)	(84.7)	(13.9)	(98.6)
Operating (loss)/income	(5.7)	6.9	(10.2)	(9.0)	(5.8)	(14.8)
Interest expense	(2.2)	(1.4)	(1.5)	(5.1)	(0.2)	(5.3)
Interest income	0.1	0.1	0.2	0.4	-	0.4
Income tax benefit	14.8	(4.2)	1.1	11.7	2.4	14.1
Loss from continuing operations	7.0	1.4	(10.4)	(2.0)	(3.6)	(5.6)
Income/(loss) from discontinued operations	-	-	12.4	12.4	(3.6)	8.8
Net (loss)/income	$ 7.0	$ 1.4	$ 2.0	$ 10.4	$ (7.2)	$ 3.2

	NU Enterprises	For the Nine Months Ended September 30, 2006				
(Millions of Dollars)	Wholesale	Retail	Generation	Total Merchant Energy	Services and Other	Totals
Operating revenues	$ 2.2	$ 583.1	$ 234.3	$ 819.6	$ 34.4	$ 854.0
Depreciation and amortization	-	-	(0.2)	(0.2)	(0.3)	(0.5)
Wholesale contract market changes, net	(14.1)	-	(0.8)	(14.9)	-	(14.9)
Restructuring and impairment charges	(0.2)	(3.2)	(0.3)	(3.7)	(6.0)	(9.7)

Other operating expenses	0.8	(682.7)	(256.3)	(938.2)	(43.2)	(981.4)
Operating loss	(11.3)	(102.8)	(23.3)	(137.4)	(15.1)	(152.5)
Interest expense	(8.5)	(6.6)	(7.4)	(22.5)	(0.2)	(22.7)
Interest income	0.8	1.4	1.4	3.6	0.4	4.0
Other income/(loss), net	(0.4)	(0.1)	0.2	(0.3)	0.5	0.2
Income tax benefit	19.2	36.8	9.7	65.7	4.3	70.0
Loss from continuing operations	(0.2)	(71.3)	(19.4)	(90.9)	(10.1)	(101.0)
Income/(loss) from discontinued operations	-	-	36.3	36.3	(9.0)	27.3
Net (loss)/income	$ (0.2)	$ (71.3)	$ 16.9	$ (54.6)	$ (19.1)	$ (73.7)

	NU Enterprises - For the Three Months Ended September 30, 2005		
(Millions of Dollars)	**Total Merchant Energy**	**Services and Other**	**Totals**
Operating revenues	$ 311.7	$ 26.5	$ 338.2
Depreciation and amortization	(0.4)	(0.1)	(0.5)
Wholesale contract market changes, net	(101.2)	-	(101.2)
Restructuring and impairment charges	(4.2)	(0.6)	(4.8)
Other operating expenses	(384.2)	(26.2)	(410.4)
Operating loss	(178.3)	(0.4)	(178.7)
Interest expense	(3.7)	(0.1)	(3.8)
Interest income	0.8	-	0.8
Other income, net	(0.7)	0.2	(0.5)
Income tax benefit	47.0	0.4	47.4
Loss from continuing operations	(134.9)	0.1	(134.8)
Income/(loss) from discontinued operations	7.7	(2.5)	5.2
Net loss	$ (127.2)	$ (2.4)	$ (129.6)

	NU Enterprises - For the Nine Months Ended September 30, 2005		
(Millions of Dollars)	Total Merchant Energy	Services and Other	Totals
Operating revenues	$ 1,435.8	$ 77.1	$ 1,512.9
Depreciation and amortization	(2.0)	(0.6)	(2.6)
Wholesale contract market changes, net	(359.7)	-	(359.7)
Restructuring and impairment charges	(19.8)	(8.7)	(28.5)
Other operating expenses	(1,557.5)	(86.9)	(1,644.4)
Operating loss	(503.2)	(19.1)	(522.3)
Interest expense	(10.8)	(0.4)	(11.2)
Interest income	2.3	0.7	3.0
Other loss, net	(1.1)	0.2	(0.9)
Income tax benefit	170.3	5.5	175.8
Loss from continuing operations	(342.5)	(13.1)	(355.6)
Loss from discontinued operations	32.9	(21.4)	11.5
Net loss	$ (309.6)	$ (34.5)	$ (344.1)

13.

SUBSEQUENT EVENTS

FERC ROE Decision: On October 31, 2006, the FERC issued its decision on the ROE and incentives for the New England transmission owners. The FERC set the base ROE (before incentives) at 10.2 percent for the historical locked-in period of February 1, 2005 (when the New England RTO was activated) to October 31, 2006. The FERC also added 74 basis points for the true up of the 10-year treasury rate, bringing the going forward base ROE to 10.94 percent, effective on November 1, 2006. In addition, the FERC approved a 50 basis point adder for joining an RTO and approved a 100 basis point adder for all new transmission investment where the projects have been identified as necessary by the ISO-NE regional planning process. Both ROE adders for certain projects are retroactive to February 1, 2005.

Prior to this decision, the base ROE being utilized in the calculation of LNS transmission wholesale rates was 12.8 percent. The ROE being utilized in the calculation of RNS transmission wholesale rates was 12.8 percent base plus a 50 basis point adder for joining an RTO, or a total of 13.3 percent, plus an additional 100 basis point adder on new regional transmission investment.

For purposes of revenue recognition, prior to this ROE decision, the transmission business assumed an ROE of 11.5 percent after the implementation of the RTO on February 1, 2005. As a result of the difference in the 12.8 percent base ROE and the 13.3 percent ROE being billed to LNS and RNS customers, respectively, and the 11.5 percent ROE assumed for earnings accruals and estimates through September 30, 2006, a $14.1 million liability for refunds has been accumulated and recorded.

The final amount of refunds and the impact on 2006 earnings will be determined and recorded when the calculation of the ROE for the historical locked-in period of February 1, 2005 to October 31, 2006 is completed in the fourth quarter of 2006. NU and the other RTO members are currently evaluating the FERC's decision to quantify its financial impacts and determine their next course of action. Management believes that any increase to the $14.1 million liability already recorded for the locked-in period will not be material to NU's financial statements.

Competitive Generation Business: On November 1, 2006, NU completed the sale of its 100 percent ownership in NGC and HWP's 146-MW Mt. Tom plant to ECP. NU will record an after-tax gain of approximately $300 million in the fourth quarter of 2006 related to this sale.

SESI Guarantees: On October 27, 2006, NU closed on a settlement agreement with an investor and paid approximately $1 million to eliminate its obligations under the guarantee. For further information regarding the status of this issue, see Note 7A, "Commitments and Contingencies - Guarantees and Indemnifications."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of
Northeast Utilities
Berlin, Connecticut

We have reviewed the accompanying condensed consolidated balance sheet of Northeast Utilities and subsidiaries (the Company) as of September 30, 2006, and the related condensed consolidated statements of income/(loss) for the three-month and nine-month periods ended September 30, 2006 and 2005, and of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 2 and 3, the Company recorded significant charges in the three-month and nine-month periods ended September 30, 2006 and 2005 in connection with its decision to exit certain business lines. Also, as discussed in Note 4, the presentation of the prior period financial statements has been revised to present certain components of the Company s generation business as discontinued operations.

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, 2005, and the related consolidated statements of loss, comprehensive loss, shareholders equity, and cash flows for the year then ended (not presented herein); and in our report dated March 7, 2006 (June 7, 2006 as to Notes 1B, 1H, 1P, 1V, 2, 4, 12, 16, 17, and 18) (which report included an explanatory paragraph related to the recording of significant charges in connection with the Company s decision to exit certain business lines and the presentation of certain components of the Company s energy service businesses as discontinued operations), 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, 2005 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 8, 2006

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 6,734	$ 2,301
Investments in securitizable assets	273,085	252,801
Receivables, less provision for uncollectible accounts of $2,087 in 2006 and $1,982 in 2005	77,977	80,883
Accounts receivable from affiliated companies	106	17,214
Unbilled revenues	6,648	7,888
Materials and supplies	38,771	32,929
Derivative assets - current	42,250	82,578
Prepayments and other	31,278	18,003
	476,849	494,597
Property, Plant and Equipment:		
Electric utility	4,449,400	3,997,652
Less: Accumulated depreciation	1,242,314	1,175,164
	3,207,086	2,822,488
Construction work in progress	295,059	344,204
	3,502,145	3,166,692
Deferred Debits and Other Assets:		
Regulatory assets	1,367,953	1,357,985
Prepaid pension	315,985	315,532
Derivative assets - long-term	247,979	308,648
Other	170,653	121,618

		2,102,570	2,103,783
Total Assets	$	6,081,564	$ 5,765,072

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, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 130,000	$ -
Notes payable to affiliated companies	11,125	26,825
Accounts payable	306,464	253,974
Accounts payable to affiliated companies	42,593	39,755
Accrued taxes	2,919	60,531
Accrued interest	32,062	16,947
Derivative liabilities - current	6,064	477
Other	66,944	70,025
	598,171	468,534
Rate Reduction Bonds	783,262	856,479
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	918,481	774,190
Accumulated deferred investment tax credits	24,671	85,970
Deferred contractual obligations	197,811	243,279
Regulatory liabilities	539,772	742,993
Derivative liabilities - long-term	32,269	31,774
Other	134,885	131,253
	1,847,889	2,009,459

Capitalization:			
Long-Term Debt		1,516,541	1,258,883
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 2006 and 2005		60,352	60,352
Capital surplus, paid in		671,827	612,815
Retained earnings		482,996	382,628
Accumulated other comprehensive income/(loss)		4,326	(278)
Common Stockholder's Equity		1,219,501	1,055,517
Total Capitalization		2,852,242	2,430,600
Commitments and Contingencies (Note 7)			
Total Liabilities and Capitalization	$	6,081,564	$ 5,765,072

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,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 1,083,299	$ 952,444	$ 3,027,779	$ 2,588,913
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	726,271	590,091	1,992,936	1,613,087
Other	157,626	145,576	469,701	403,720
Maintenance	31,246	28,341	74,803	70,820
Depreciation	37,798	33,509	110,224	98,966
Amortization of regulatory (liabilities)/assets, net	(1,811)	23,046	(6,132)	28,254
Amortization of rate reduction bonds	33,614	31,477	96,137	89,855
Taxes other than income taxes	42,847	40,608	123,385	118,910
Total operating expenses	1,027,591	892,648	2,861,054	2,423,612
Operating Income	55,708	59,796	166,725	165,301
Interest Expense:				
Interest on long-term debt	20,634	15,548	54,287	43,505
Interest on rate reduction bonds	11,459	13,707	36,025	42,677
Other interest	(254)	327	4,170	6,271
Interest expense, net	31,839	29,582	94,482	92,453
Other Income, Net	10,182	10,037	27,574	22,091
Income Before Income Tax Expense	34,051	40,251	99,817	94,939

Income Tax (Benefit)/Expense	(66,982)	12,788	(52,518)	28,500
Net Income	$ 101,033	$ 27,463	$ 152,335	$ 66,439

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, 2006	2005
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 152,335	$ 66,439
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	12,651	9,871
Depreciation	110,224	98,966
Deferred income taxes	10,391	7,574
Amortization of regulatory (liabilities)/assets, net	(6,132)	28,254
Amortization of rate reduction bonds	96,137	89,855
(Deferral)/amortization of recoverable energy costs	(3,937)	15,008
Pension (income)/expense	(2,480)	548
Regulatory refunds	(117,670)	(75,020)
Deferred contractual obligations	(48,657)	(45,436)
Other non-cash adjustments	(13,718)	4,537
Other sources of cash	14,171	3,184
Other uses of cash	(4,462)	(16,092)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	8,603	42,165
Materials and supplies	(5,842)	788
Investments in securitizable assets	(20,284)	(81,551)
Other current assets	(13,179)	(11,976)
Accounts payable	26,853	(28,676)
(Taxes receivable)/accrued taxes	(57,612)	44,056
Other current liabilities	11,464	6,747

Net cash flows provided by operating activities		148,856		159,241
Investing Activities:				
Investments in plant		(388,365)		(308,955)
Proceeds from sales of investment securities		1,524		1,289
Purchases of investment securities		(1,566)		(1,331)
Net proceeds from sale of land		-		21,993
Rate reduction bond escrow		(52,020)		(4,806)
Other investing activities		(1,620)		5,264
Net cash flows used in investing activities		(442,047)		(286,546)
Financing Activities:				
Issuance of long-term debt		250,000		200,000
Retirement of rate reduction bonds		(73,217)		(105,224)
Capital contributions from Northeast Utilities		60,000		140,009
Increase in short-term debt		130,000		15,000
Decrease in NU Money Pool borrowing		(15,700)		(80,200)
Cash dividends on preferred stock		(4,169)		(4,169)
Cash dividends on common stock		(47,798)		(40,376)
Other financing activities		(1,492)		(1,797)
Net cash flows provided by financing activities		297,624		123,243
Net increase/(decrease) in cash		4,433		(4,062)
Cash - beginning of period		2,301		5,608
Cash - end of period	$	6,734	$	1,546

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

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PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 3,227	$ 27
Receivables, less provision for uncollectible accounts of $2,492 in 2006 and $2,362 in 2005	86,731	95,599
Accounts receivable from affiliated companies	634	20,348
Unbilled revenues	34,198	47,705
Taxes receivable	14,426	-
Fuel, materials and supplies	78,485	72,820
Prepayments and other	3,760	11,987
	221,461	248,486
Property, Plant and Equipment:		
Electric utility	1,812,307	1,732,716
Other	5,816	5,816
	1,818,123	1,738,532
Less: Accumulated depreciation	730,295	698,480
	1,087,828	1,040,052
Construction work in progress	119,577	115,371
	1,207,405	1,155,423
Deferred Debits and Other Assets:		
Regulatory assets	418,748	821,951
Other	73,383	68,723
	492,131	890,674

Total Assets	$ 1,920,997	$ 2,294,583

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, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to affiliated companies	$ 7,500	$ 15,900
Accounts payable	59,446	63,320
Accounts payable to affiliated companies	22,377	16,738
Accrued taxes	-	5,186
Accrued interest	12,394	8,202
Other	15,455	15,733
	117,172	125,079
Rate Reduction Bonds	346,909	382,692
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	199,836	242,590
Accumulated deferred investment tax credits	965	1,230
Deferred contractual obligations	37,993	48,262
Regulatory liabilities	124,379	414,558
Accrued pension	91,656	76,446
Other	44,842	44,136
	499,671	827,222
Capitalization:		
Long-Term Debt	507,096	507,086
Common Stockholder's Equity:		
Common stock, $1 par value - authorized 100,000,000 shares; 301 shares outstanding		

in 2006 and 2005	-	-
Capital surplus, paid in	214,948	209,788
Retained earnings	235,065	242,633
Accumulated other comprehensive income	136	83
Common Stockholder's Equity	450,149	452,504
Total Capitalization	957,245	959,590
Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$ 1,920,997	$ 2,294,583

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 INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 267,092	$ 307,305	$ 877,046	$ 835,782
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	148,908	134,569	439,110	383,056
Other	42,729	44,184	130,887	132,974
Maintenance	17,807	13,758	53,544	48,868
Depreciation	12,568	11,755	37,021	34,596
Amortization of regulatory (liabilities)/assets, net	(5,690)	56,199	60,530	99,907
Amortization of rate reduction bonds	12,622	11,907	36,788	34,820
Taxes other than income taxes	9,737	9,434	28,755	27,911
Total operating expenses	238,681	281,806	786,635	762,132
Operating Income	28,411	25,499	90,411	73,650
Interest Expense:				
Interest on long-term debt	6,206	4,886	17,889	14,760
Interest on rate reduction bonds	5,083	5,928	15,912	18,346
Other interest	132	597	577	1,506
Interest expense, net	11,421	11,411	34,378	34,612
Other Income, Net	897	92	2,927	1,072
Income Before Income Tax Expense	17,887	14,180	58,960	40,110

Income Tax Expense	9,997	2,259	31,034	10,338
Net Income	$ 7,890	$ 11,921	$ 27,926	$ 29,772

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, 2006	Nine Months Ended September 30, 2005
	(Thousands of Dollars)	
Operating activities:		
Net income	$ 27,926	$ 29,772
Adjustments to reconcile to net cash flows provided by operating activities:		
Bad debt expense	3,119	3,147
Depreciation	37,021	34,596
Deferred income taxes	(20,392)	(49,238)
Amortization of regulatory assets, net	60,530	99,907
Amortization of rate reduction bonds	36,788	34,820
Pension expense	8,114	9,837
Regulatory (underrecoveries)/overrecoveries	(4,243)	5,444
Deferred contractual obligations	(10,219)	(9,417)
Other non-cash adjustments	(8,473)	(17)
Other sources of cash	434	9
Other uses of cash	(6,385)	(11,960)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	38,970	(572)
Fuel, materials and supplies	(5,665)	(8,800)
Other current assets	8,390	8,575
Accounts payable	10,617	(11,574)
(Taxes receivable)/accrued taxes	(19,612)	45,531
Other current liabilities	3,910	3,957
Net cash flows provided by operating activities	160,830	184,017
Investing Activities:		
Investments in plant	(81,874)	(124,489)

Proceeds from sales of investment securities	2,613	2,208
Purchases of investment securities	(2,683)	(2,282)
Net proceeds from sale of land	-	857
Increase in NU Money Pool Lending	-	(12,100)
Other investing activities	(1,267)	(4,515)
Net cash flows used in investing activities	(83,211)	(140,321)
Financing Activities:		
Retirement of rate reduction bonds	(35,783)	(33,734)
Increase in short-term debt	-	10,000
Decrease in NU Money Pool borrowing	(8,400)	(20,400)
Capital contributions from Northeast Utilities	5,500	18,644
Cash dividends on common stock	(35,494)	(18,383)
Other financing activities	(242)	128
Net cash flows used in financing activities	(74,419)	(43,745)
Net increase/(decrease) in cash	3,200	(49)
Cash - beginning of period	27	4,855
Cash - end of period	$ 3,227	$ 4,806

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

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WESTERN MASSACHUSETTS ELECTRIC COMPANY

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WESTERN MASSACHUSETTS ELECTRIC COMPANY AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006	December 31, 2005
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash	$ 776	$ 1
Receivables, less provision for uncollectible accounts of $5,014 in 2006 and $3,653 in 2005	43,392	43,490
Accounts receivable from affiliated companies	191	5,752
Unbilled revenues	13,091	16,411
Taxes receivable	4,298	-
Materials and supplies	1,597	1,414
Marketable securities - current	24,346	20,905
Prepayments and other	827	897
	88,518	88,870
Property, Plant and Equipment:		
Electric utility	692,007	671,292
Less: Accumulated depreciation	199,638	193,151
	492,369	478,141
Construction work in progress	27,130	21,176
	519,499	499,317
Deferred Debits and Other Assets:		
Regulatory assets	236,798	223,174
Prepaid pension	81,759	80,618
Marketable securities - long-term	28,842	30,434

Other		21,896		23,583
		369,295		357,809
Total Assets	$	977,312	$	945,996

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, 2006	December 31, 2005
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 30,000	$ -
Notes payable to affiliated companies	3,600	14,900
Accounts payable	21,817	31,333
Accounts payable to affiliated companies	7,446	9,015
Accrued taxes	466	1,620
Accrued interest	1,639	4,517
Other	8,920	9,364
	73,888	70,749
Rate Reduction Bonds	102,384	111,331
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	233,570	219,992
Accumulated deferred investment tax credits	2,403	2,655
Deferred contractual obligations	54,140	66,633
Regulatory liabilities	23,914	23,836
Other	13,237	11,977
	327,264	325,093
Capitalization:		
Long-Term Debt	261,016	259,487
Common Stockholder's Equity:		
Common stock, $25 par value - authorized 1,072,471 shares; 434,653 shares outstanding		

in 2006 and 2005		10,866		10,866
Capital surplus, paid in		110,587		82,811
Retained earnings		90,484		84,965
Accumulated other comprehensive income		823		694
Common Stockholder's Equity		212,760		179,336
Total Capitalization		473,776		438,823
Commitments and Contingencies (Note 7)				
Total Liabilities and Capitalization	$	977,312	$	945,996

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,	
	2006	2005	2006	2005
	(Thousands of Dollars)			
Operating Revenues	$ 104,959	$ 104,611	$ 333,035	$ 302,263
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	66,171	62,698	216,463	179,756
Other	15,268	16,583	48,221	50,963
Maintenance	4,400	3,742	11,753	11,777
Depreciation	4,315	4,079	12,842	12,147
Amortization of regulatory (liabilities)/assets, net	(1,614)	182	(7,071)	(2,753)
Amortization of rate reduction bonds	2,924	2,739	8,911	8,354
Taxes other than income taxes	2,902	2,475	9,026	8,767
Total operating expenses	94,366	92,498	300,145	269,011
Operating Income	10,593	12,113	32,890	33,252
Interest Expense:				
Interest on long-term debt	2,644	2,468	8,066	6,794
Interest on rate reduction bonds	1,654	1,867	5,123	5,752
Other interest	304	265	946	1,012
Interest expense, net	4,602	4,600	14,135	13,558
Other Income, Net	582	957	1,588	1,416
Income Before Income Tax Expense	6,573	8,470	20,343	21,110
Income Tax Expense	2,901	3,613	8,865	9,158

Net Income	$ 3,672	$ 4,857	$ 11,478	$ 11,952

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,	
	2006	2005
	(Thousands of Dollars)	
Operating Activities:		
Net income	$ 11,478	$ 11,952
Adjustments to reconcile to net cash flows		
provided by operating activities:		
Bad debt expense	4,309	2,933
Depreciation	12,842	12,147
Deferred income taxes	13,976	(110)
Amortization of regulatory liabilities, net	(7,071)	(2,753)
Amortization of rate reduction bonds	8,911	8,354
Pension income	(882)	(521)
Regulatory (underrecoveries)/overrecoveries	(15,704)	7,334
Deferred contractual obligations	(13,378)	(12,394)
Other non-cash adjustments	56	(463)
Other sources of cash	2,559	-
Other uses of cash	-	(5,035)
Changes in current assets and liabilities:		
Receivables and unbilled revenues, net	4,670	310
Materials and supplies	(183)	213
Other current assets	161	261
Accounts payable	(10,017)	(12,183)
Accrued taxes	(5,452)	10,754
Other current liabilities	(2,865)	(2,089)
Net cash flows provided by operating activities	3,410	18,710

Investing Activities:		
Investments in plant	(32,323)	(30,792)
Proceeds from sales of investment securities	76,428	59,413
Purchases of investment securities	(78,282)	(60,606)
Net proceeds from sale of land	-	1,599
Other investing activities	(69)	1,458
Net cash flows used in investing activities	(34,246)	(28,928)
Financing Activities:		
Issuance of long-term debt	-	50,000
Retirement of rate reduction bonds	(8,947)	(8,391)
Increase/(decrease) in short-term debt	30,000	(18,000)
Decrease in NU Money Pool borrowing	(11,300)	(14,500)
Capital contributions from Northeast Utilities	28,000	6,920
Cash dividends on common stock	(5,959)	(5,763)
Other financing activities	(183)	(318)
Net cash flows provided by financing activities	31,611	9,948
Net increase/(decrease) in cash	775	(270)
Cash - beginning of period	1	1,678
Cash - end of period	$ 776	$ 1,408

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

This discussion should be read in conjunction with the condensed consolidated financial statements and footnotes in this Form 10-Q, the First and Second Quarter 2006 reports on Form 10-Q and the NU 2005 Form 10-K as amended by NU's report on Form 8-K dated June 7, 2006 to classify certain businesses as discontinued operations. All per share amounts are reported on a fully diluted basis.

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:

- Northeast Utilities (NU or the company) earned $111.5 million, or $0.72 per share, in the third quarter of 2006, compared with a loss of $94.5 million, or $0.73 per share, in the third quarter of 2005. The results for the third quarter of 2006 included Utility Group net income of $105.9 million, or $0.69 per share, after payment of preferred dividends, NU Enterprises, Inc. (NU Enterprises) net income of $3.2 million, or $0.02 per share, and parent company and other income of $2.4 million, or $0.01 per share. In the first nine months of 2006, NU earned $123.6 million, or $0.80 per share, compared with a loss of $239.9 million, or $1.85 per share, in the first nine months of 2005. Results in the third quarter and the first nine months of 2006 included a reduction in income tax expense at The Connecticut Light and Power Company's (CL&P) distribution business totaling $74 million pursuant to a private letter ruling (PLR) received from the Internal Revenue Service (IRS). Excluding the impact of the PLR, NU earned $37.5 million, or $0.23 per share in the third quarter of 2006 and $49.6 million, or $0.32 per share for the first nine months of 2006. The losses in 2005 resulted from wholesale contract market changes and restructuring and impairment charges at NU Enterprises associated with the decision to exit the wholesale marketing business and the energy services businesses.

- Earnings at the distribution businesses of CL&P, Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO) and Yankee Gas Services Company (Yankee Gas) and the regulated generation business of PSNH totaled $87.7 million in the third quarter of 2006 and $150.4 million in the first nine months of 2006, compared with $26.9 million in the third quarter of 2005 and $83.8 million in the first nine months of 2005.

- The transmission businesses of CL&P, PSNH and WMECO earned $18.2 million in the third quarter of 2006 and $43.6 million in the first nine months of 2006, compared with $11.8 million in the third quarter of 2005 and $30.5 million in the first nine months of 2005.

- Losses in the first nine months of 2006 for the NU Enterprises businesses were related primarily to the retail marketing business that was sold to Hess Corporation (Hess) on June 1, 2006. The retail marketing business lost $71.3 million for the first nine months of 2006 which includes a charge related to the sale of the retail marketing business.

- On July 24, 2006, NU reached an agreement with various affiliates of Energy Capital Partners (ECP) to sell its 100 percent ownership in Northeast Generation Company (NGC) and Holyoke Water Power Company's (HWP) 146 megawatt (MW) Mt. Tom coal-fired plant (Mt. Tom) for $1.34 billion, which includes the assumption of $320 million of NGC debt. After receiving Federal Energy Regulatory Commission (FERC) and other approvals, the sale closed on November 1, 2006. NU will record an after-tax gain of approximately $300 million in the fourth quarter of 2006.

- On October 12, 2006, CL&P energized a 21-mile 115 kilovolt (kV)/345 kV line project between Bethel, Connecticut and Norwalk, Connecticut. The final cost of the project is expected to be approximately $340 million compared to a budget of $350 million.

- Construction of the $75 million conversion of PSNH's 50 megawatt (MW) coal-fired unit at Schiller Station in Portsmouth, New Hampshire to burn wood (Northern Wood Power Project) started in 2004. The new boiler is operating under coal and/or wood at various times as part of its start-up compliance adjustment and testing, with testing expected to be completed by the end of 2006.

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NU continues to project 2006 combined earnings for the Utility Group and parent and affiliates of between $1.57 per share and $1.70 per share, including a gain in CL&P's third quarter distribution results as a result of the PLR. NU projects earnings at its regulated distribution and generating businesses to be at the low end of or slightly below its previously announced range of between $1.23 per share and $1.33 per share, transmission business earnings to be within its previously announced earnings range of between $0.34 per share and $0.37 per share and parent and affiliates results to be at or above breakeven results for 2006. NU is not providing consolidated earnings guidance or earnings guidance for NU Enterprises for 2006.

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NU projects 2007 combined earnings for the Utility Group and parent and affiliates of between $1.30 per share and $1.55 per share, which includes earnings of between $0.80 per share and $0.90 per share at the regulated distribution and generation businesses, between $0.50 per share and $0.60 per share at the transmission business and parent and affiliates results of between breakeven and earnings of $0.05 per share. NU projects approximately breakeven results at NU Enterprises for 2007, excluding mark-to-market impacts.

Regulatory and Other Items:

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In 2000, CL&P requested from the IRS a PLR regarding the treatment of unamortized investment tax credits (UITC) and excess deferred income taxes (EDIT) related to generation assets that were sold. On July 27, 2006, the Connecticut Department of Public Utility Control (DPUC) determined that the UITC and EDIT amounts were no longer required to be held in their existing accounts. The $74 million balance reduced CL&P's third quarter 2006 income tax expense and increased CL&P's earnings by the same amount.

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On August 4, 2006, CL&P notified Governor Rell and the DPUC that it intends to postpone filing a distribution rate case until mid-2007 for rates effective on January 1, 2008.

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On August 15, 2006, the Connecticut Yankee Atomic Power Company (CYAPC), the DPUC, the Connecticut Office of Consumer Counsel (OCC) and Maine state regulators filed a settlement agreement with the FERC which, if approved, disposes of the pending litigation at the FERC and the D.C. Circuit Court of Appeals (Court of Appeals) related to CYAPC's decommissioning costs, among other issues.

- In 1998, CYAPC, the Yankee Atomic Electric Company (YAEC) and the Maine Yankee Atomic Power Company (MYAPC) (collectively, the Yankee Companies) filed separate complaints against the United States Department of Energy (DOE) in the United States Court of Federal Claims (Court of Federal Claims) seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel. In a ruling released 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. CL&P, PSNH and WMECO collectively own 49 percent of CYAPC, 38.5 percent of YAEC and 20 percent of MYAPC. 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. As such, no earnings are expected to result from the court decision.

- On October 19, 2006, WMECO filed with the Massachusetts Department of Telecommunications and Energy (DTE) a settlement agreement among WMECO, the Massachusetts Attorney General and two other parties that included distribution rate increases of $1 million beginning on January 1, 2007 and an additional $3 million distribution rate increase beginning on January 1, 2008. Also included in the settlement agreement are cost tracking mechanisms for pension and other postretirement benefit costs, uncollectible amounts related to energy costs, and recovery of certain capital improvements needed for system reliability. Under this settlement agreement, management expects that a return on capital investment of between 9 percent and 10 percent annually is achievable for WMECO.

- On October 31, 2006, the FERC issued its decision on the ROE and incentives for the New England transmission owners. The FERC set the base ROE (before incentives) at 10.2 percent for the historical locked-in period of February 1, 2005 (when the New England RTO was activated) to October 31, 2006. The FERC also added 74 basis points for the true up of the 10-year treasury rate, bringing the going forward base ROE to 10.94 percent, effective on November 1, 2006. In addition, the FERC approved a 50 basis point adder for joining an RTO and approved a 100 basis point adder for all new transmission investment where the projects have been identified as necessary by the ISO-NE regional planning process. Both ROE adders for certain projects are retroactive to February 1, 2005.

Liquidity:

- NU's capital expenditures totaled $600.3 million in the first nine months of 2006, compared with $521.5 million in the first nine months of 2005. The increase in NU's capital expenditures was primarily the result of higher transmission capital expenditures, particularly at CL&P.

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Cash flows from operations increased by $27.5 million from $352.8 million for the first nine months of 2005 to $380.3 million for the first nine months of 2006. The increase in operating cash flows is primarily due to the sale of the retail marketing business resulting in cash collections of accounts receivable in excess of cash payments on accounts payable and the absence in 2006 of $145.2 million of buyout payments made by NU Enterprises in 2005 related to long-term wholesale power contracts that were terminated. Offsetting these items are higher regulatory refunds in 2006 as CL&P refunded amounts to its ratepayers to moderate the increase in CL&P's transitional standard offer (TSO) rates that became effective on January 1, 2006 and a federal income tax payment of approximately $55 million related to NU's 2005 tax return which was made in the first quarter of 2006.

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NU's liquidity will be significantly enhanced in the fourth quarter of 2006 as a result of the sale of NGC and Mt. Tom. NU received approximately $1 billion upon closing of the sale on November 1, 2006. The company expects to pay approximately $490 million in taxes in the first quarter of 2007, net of tax benefits arising from other activities. NU expects to use the remaining approximately $510 million to fund Utility Group capital expenditures and reduce short-term debt.

Overview

Consolidated: NU earned $111.5 million, or $0.72 per share, in the third quarter of 2006, compared with a loss of $94.5 million, or $0.73 per share, in the third quarter of 2005. NU earned $123.6 million, or $0.80 per share, in the first nine months of 2006, compared with a loss of $239.9 million, or $1.85 per share, in the first nine months of 2005. Earnings per share (EPS) results in 2006 include the impact of the issuance of 23 million NU common shares on December 12, 2005. A summary of NU's earnings/(losses) by major business line, which do not reflect aggregations of specific subsidiaries, for the third quarter and first nine months of 2006 and 2005 is as follows:

	For the Three Months Ended September 30,				**For the Nine Months Ended September 30,**			
(Millions of Dollars, except per share amounts)	**2006**		**2005**		**2006**		**2005**	
	Amount	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Utility Group	$ 105.9	$ 0.69	$ 38.7	$ 0.30	$ 194.0	$ 1.26	$ 114.3	$ 0.88
NU Enterprises	3.2	0.02	(129.6)	(1.00)	(73.7)	(0.48)	(344.1)	(2.65)
Parent and affiliates	2.4	0.01	(3.6)	(0.03)	3.3	0.02	(10.1)	(0.08)

Net Income/(Loss)	$ 111.5	$ 0.72	$ (94.5)	$ (0.73)	$ 123.6	$ 0.80	$ (239.9)	$ (1.85)

The only equity securities that are publicly traded are common shares of NU. The EPS of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct interest in NU's assets and liabilities as a whole. A portion of NU Enterprises results are included in discontinued operations. See the Overview - NU Enterprises section included in this management's discussion and analysis for further information.

Within the Utility Group, NU segments its electric earnings between its electric transmission and distribution businesses with generation included with the distribution business. The transmission business earned $18.2 million in the third quarter of 2006 and $43.6 million in the first nine months of 2006, compared with $11.8 million in the third quarter of 2005 and $30.5 million in the first nine months of 2005.

In the third quarter of 2006, the distribution and generation businesses, including Yankee Gas, earned $87.7 million, compared with $26.9 million in the third quarter of 2005. Those businesses earned $150.4 million in the first nine months of 2006, compared with $83.8 million in the same period of 2005.

Losses in the first nine months of 2006 for the NU Enterprises businesses were related primarily to the retail marketing business that was sold to Hess on June 1, 2006. The retail marketing business lost $71.3 million for the first nine months of 2006 reflecting losses from both electricity sales and natural gas sales and an after-tax loss of $33.3 million recorded related to the sale of the retail marketing business.

Utility Group: The Utility Group is comprised of CL&P, PSNH, WMECO and Yankee Gas, and is comprised of their applicable transmission, distribution and generation businesses. A summary of Utility Group earnings by company and business segment for the three and nine months ended September 30, 2006 and 2005 is as follows:

(Millions of Dollars)	For the Three Months Ended September 30, 2006	2005	For the Nine Months Ended September 30, 2006	2005
CL&P Distribution	$ 84.4	$ 16.9	$ 114.2	$ 40.9
CL&P Transmission	15.2	9.2	34.0	21.4
Total CL&P*	99.6	26.1	148.2	62.3
PSNH Distribution and Generation	5.8	10.5	21.2	24.0
PSNH Transmission	2.1	1.5	6.7	5.8
Total PSNH	7.9	12.0	27.9	29.8
WMECO Distribution	2.8	3.7	8.6	8.6
WMECO Transmission	0.9	1.1	2.9	3.3
Total WMECO	3.7	4.8	11.5	11.9
Yankee Gas	(5.3)	(4.2)	6.4	10.3
Total Distribution and Generation	87.7	26.9	150.4	83.8
Total Transmission	18.2	11.8	43.6	30.5
Total Utility Group Net Income	$ 105.9	$ 38.7	$ 194.0	$ 114.3

*After preferred dividends in all periods.

CL&P's distribution earnings in the third quarter of 2006 were higher than the same period of 2005 as a result of a PLR that reduced CL&P's 2006 income tax expense by $74 million. Excluding the impact of the PLR, CL&P's third quarter 2006 distribution earnings were lower than 2005 due to lower sales that offset CL&P's distribution rate increase effective January 1, 2006, and higher storm-related operating costs. For the first nine months of 2006, CL&P's distribution earnings were higher than the first nine months of 2005 as a result of the PLR. Excluding the $74 million impact of the PLR, CL&P's distribution earnings were essentially the same for the first nine months of 2006 and 2005. CL&P's 2006 earnings benefited from an approximate $12 million distribution rate increase effective January 1, 2006 and from the settlement of a tax case with the State of Connecticut, but these items were offset by lower sales, increased storm-related costs, and higher depreciation and interest expenses. CL&P's Regulatory return on equity (ROE) on a trailing 12-month basis is approximately 7 percent compared with its allowed ROE of 9.85 percent.

For the three and nine months ended September 30, 2006, CL&P transmission earnings were higher due to a higher level of investment in its transmission system as compared with similar periods in 2005.

PSNH's distribution and generation earnings in the third quarter and first nine months of 2006 were lower as compared with similar periods in 2005 primarily due to a higher effective tax rate, partially offset by the distribution rate increases which were effective on June 1, 2005 and July 1, 2006. The higher effective tax rate is primarily due to two items; higher unitary taxes resulting from the sale of NU's competitive generation assets and full recovery in the second quarter of 2006 of a deferred tax expense in PSNH's non-securitized Part 3 stranded costs. The deferred tax expense is being recorded pro rata throughout 2006 even though the associated pre-tax income impacts were recorded entirely in the second quarter. PSNH's Regulatory ROE on a trailing 12-month basis is approximately 7 percent.

PSNH's transmission earnings for the third quarter and first nine months of 2006 were higher as compared with similar periods in 2005 due to higher earnings resulting from a higher rate base, partially offset by the increase of certain expenses as allowed by the annual local network service (LNS) tariff that provides for a true-up to actual costs.

WMECO's distribution results in the third quarter of 2006 were lower than 2005 primarily due to higher operating expenses, and a 5.7 percent decrease in retail sales partially offset by a $3 million distribution rate increase that took effect on January 1, 2006. WMECO's distribution results for the first nine months of 2006 were comparable to 2005 as a result of the January 1, 2006 rate increase being offset by lower sales and higher operating and interest expenses. WMECO's Regulatory ROE on a trailing 12-month basis is approximately 10 percent.

WMECO's transmission earnings for the third quarter and first nine months of 2006 were lower due to the increase of certain expenses as allowed by the annual LNS tariff that provides for a true-up to actual costs, partially offset by higher rate base earnings.

Yankee Gas' results in the third quarter and first nine months of 2006 were lower as compared with similar periods in 2005. Yankee Gas' results for the third quarter of 2006 were lower primarily due to higher sales taxes and a higher effective tax rate, and for the first nine months of 2006, earnings were lower primarily due to a 9.3 percent decline in firm natural gas retail sales, mostly caused by milder weather in the first quarter of 2006. Yankee Gas' Regulatory ROE on a trailing 12-month basis is approximately 7 percent compared with its allowed ROE of 9.9 percent.

The Utility Group's retail electric sales in the first nine months of 2006 were negatively affected by weather impacts in each quarter of 2006 as compared with 2005 and by price elasticity driven by higher energy prices in 2006. Retail kilowatt-hour (kWh) electric sales decreased by 4.5 percent in the third quarter of 2006 as compared with the third quarter of 2005 (a 1.8 percent decrease on a weather-normalized basis). Retail electric sales decreased by 3.6 percent in the first nine months of 2006 (a 1.1 percent decrease on a weather-normalized basis) compared with the first nine months of 2005. Residential electric sales in the first nine months of 2006 decreased by 4.9 percent from 2005; commercial electric sales decreased by 2 percent; and industrial sales decreased by 4 percent. Absent the impacts of the weather, the decline in sales is due primarily to higher prices driven by the higher fuel and purchased power costs.

NU Enterprises: At September 30, 2006, NU Enterprises was the parent of Select Energy, Inc. (Select Energy), NGC, Northeast Generation Services Company (NGS) and its subsidiary, E.S. Boulos Company (Boulos), Select Energy Contracting, Inc. - Connecticut (SECI-CT), which is a division of Select Energy Contracting, Inc. (SECI), all of which are collectively referred to as "NU Enterprises." Along with NGC, the generation operations of HWP's Mt. Tom plant were included in the results of NU Enterprises until they were sold on November 1, 2006.

At September 30, 2006, the merchant energy business included Select Energy's wholesale marketing business, 1,442 MW of generation assets, including 1,296 MW of primarily pumped storage and hydroelectric generation assets at NGC and 146 MW of coal-fired generation assets at HWP related to Mt. Tom, and NGS. At September 30, 2006, the energy services businesses included the operations of Boulos and SECI-CT.

NU's condensed consolidated statements of income/(loss) for the three and nine months ended September 30, 2006 and 2005 present the operations for the following companies as discontinued operations:

- NGC, which was sold on November 1, 2006 to ECP,
- Mt. Tom, which was sold on November 1, 2006 to ECP,
- Select Energy Services, Inc. (SESI), which was sold in May of 2006 to Ameresco, Inc. (Ameresco),
- A portion of Woods Electrical Co., Inc. (Woods Electrical), which was sold in April of 2006 to WESDAC, LLC.

- Select Energy Contracting, Inc. - New Hampshire (SECI-NH) (including Reeds Ferry Supply Co., Inc. (Reeds Ferry)), which was sold in November of 2005 to Denron Plumbing & HVAC, LLC., and

- Woods Network Services, Inc. (Woods Network), which was sold in November of 2005 to Barn Systems, Inc.

A summary of NU Enterprises' earnings/(losses) for the three and nine months ended September 30, 2006 and 2005 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**
Merchant Energy	$ 10.4	$ (127.2)	$ (54.6)	$ (309.6)
Energy Services, Parent and Other	(7.2)	(2.4)	(19.1)	(34.5)
Net Income/(Loss)	$ 3.2	$ (129.6)	$ (73.7)	$ (344.1)

A summary of NU Enterprises' earnings/(losses) from continuing operations and discontinued operations for the three and nine months ended September 30, 2006 and 2005 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	**2006**	**2005**	**2006**	**2005**
Continuing Operations:				
Merchant Energy	$ (2.0)	$ (134.9)	$ (90.9)	$ (342.5)
Energy Services, Parent and Other	(3.6)	0.1	(10.1)	(13.1)
	(5.6)	(134.8)	(101.0)	(355.6)
Discontinued Operations:				
Merchant Energy	12.4	7.7	36.3	32.9
Energy Services, Parent and Other	(3.6)	(2.5)	(9.0)	(21.4)
	8.8	5.2	27.3	11.5
Net Income/(Loss)	$ 3.2	$ (129.6)	$ (73.7)	$ (344.1)

The merchant energy earnings included in discontinued operations relate to NGC's and Mt. Tom's contracts with Select Energy. NU Enterprises' wholesale and retail marketing businesses are not included in discontinued operations because they do not meet the accounting criteria for this presentation. Retail marketing business results are included as continuing operations, as separate financial information for the retail marketing business is not available due to the manner in which the merchant energy business operated prior to January 1, 2006.

The retail marketing business lost $71.3 million for the first nine months of 2006 reflecting losses from both electricity sales and natural gas sales and an after-tax loss of $33.3 million recorded related to the sale of the retail marketing business.

The losses on electricity sales were caused primarily by replacing the electricity supply at current prices. When the decision to exit the competitive generation and retail marketing businesses was announced, the resources of the competitive generation business that were previously dedicated to the retail marketing business at a fixed price were separated from the retail marketing business, exposing the portfolio of retail sales to current market prices. Market prices have generally been higher than those that would have been charged by the competitive generation business (with the competitive generation business receiving a partially offsetting benefit). The retail marketing business losses on natural gas were primarily the result of mild weather which lowered demand and created a surplus of supply which was either sold at a loss or remained in storage with a reduced fair value.

The combined wholesale marketing and competitive generation businesses recorded earnings of $9 million in the third quarter of 2006 and earnings of $16.7 million in the first nine months of 2006. Included in these results were higher 2006 competitive generation business earnings as compared with 2005. Competitive generation business earnings were higher in 2006 than 2005 as this business is selling its products into a market that is generally higher than sales to the retail marketing business. However, short-term energy prices have continued to decrease during 2006 reducing the value received from sales of generation products. Also included in the competitive generation business earnings are $7.8 million of tax related impacts associated with the sale of its generation assets.

The combined wholesale marketing and competitive generation businesses operations in the third quarter of 2005 and the first nine months of 2005 reflect the impacts of NU's March 2005 decision to exit the wholesale marketing business. As a result of that decision, third party sales contracts and the majority of contracts intended to source a combination of retail and wholesale loads were marked-to-market.

The losses at the energy services businesses, parent and other for the third quarter of 2006 and the first nine months of 2006 are due to charges recorded in the third quarter of 2006. These charges related to the following:

- Collectibility of accounts receivable and other assets;
- Contingencies and costs related to ongoing projects that have been retained, including litigation, warranty and other contingencies;

- Costs related to the valuation and termination of guarantees; and
- Adjustments under various purchase and sale agreements.

As a result of this review, the energy services businesses recorded an after-tax loss totaling approximately $6 million in the third quarter of 2006. The energy services businesses may record additional losses as these contingencies are resolved.

Losses on the sale of these businesses also contributed to the loss for the first nine months of 2006. However, the improved results in the first nine months of 2006 are due to the absence in 2006 of $25.3 million in after-tax of restructuring and impairment charges that were recorded in the first quarter of 2005.

For information regarding the current status of the exit from the wholesale marketing, retail marketing, competitive generation and energy services businesses, see "NU Enterprises Divestitures," included in this management's discussion and analysis.

Parent and Affiliates: Parent company and affiliates after-tax income totaled $2.4 million in the third quarter of 2006 and $3.3 million in the first nine months of 2006, compared with expenses of $3.6 million in the third quarter of 2005 and $10.1 million in the first nine months of 2005. The third quarter and first nine months of 2006 improved results as compared to the same periods in 2005 primarily related to an increase in investment income generated by parent company investments in the NU money pool (pool), which are eliminated in consolidation along with the corresponding interest expense for the pool borrowers. In 2006, in addition to the higher investment income, a $2 million after-tax gain associated with the sale of NU's 2.7 million shares of Globix Corporation, a telecommunications company also contributed to the increase from 2005. Improved results for the first nine months of 2006 were negatively impacted by additional environmental reserves totaling $1.3 million which were recorded by HWP associated with its manufactured gas plant coal tar site.

Future Outlook

NU continues to project 2006 combined earnings for the Utility Group and parent company of between $1.57 per share and $1.70 per share, including CL&P's one-time $74 million reduction of distribution income tax expense pursuant to the PLR. NU projects 2007 combined earnings for the Utility Group and parent company of between $1.30 per share and $1.55 per share.

Utility Group Distribution: NU projects earnings at its regulated distribution and generating businesses to be at the low end of or slightly below its previously announced range of between $1.23 per share and $1.33 per share, including the reduction in CL&P s income tax expense as a result of the PLR. NU projects 2007 earnings at its distribution and regulated generation businesses of between $0.80 per share and $0.90 per share.

Utility Group Transmission: NU projects transmission business earnings to within previously announced earnings range of between $0.34 per share and $0.37 per share. NU projects transmission business earnings of between $0.50 per share and $0.60 per share in 2007.

Parent and Affiliates: NU expects parent and affiliates results to be at or above breakeven results for 2006 and to be between breakeven and earnings of $0.05 per share in 2007.

Management believes that the company can achieve earnings growth of between 10 percent and 14 percent from 2007 through 2011, excluding the impact of the PLR in 2006. NU assumes that an ROE of between 9 percent and 10 percent is achievable for all of its distribution and generation businesses after PSNH, CL&P and Yankee Gas receive rate relief effective on January 1, 2008 and July 1, 2007, respectively.

NU Enterprises: NU is not providing 2006 earnings guidance for NU Enterprises, which the company continues to exit. NU projects approximately breakeven results at NU Enterprises in 2007, excluding mark-to-market impacts.

Liquidity

Consolidated: NU continues to maintain an ample level of liquidity. At September 30, 2006, NU's total unused borrowing capacity through its $700 million revolving credit agreement, the Utility Group's $400 million revolving credit agreement and CL&P's $100 million accounts receivable facility totaled approximately $745 million. At September 30, 2006, NU also had $50.5 million of cash and cash equivalents on hand, compared with $45.8 million at December 31, 2005.

Cash flows from operations increased by $27.5 million from $352.8 million for the first nine months of 2005 to $380.3 million for the first nine months of 2006. The increase in operating cash flows is primarily due to the absence in 2006 of $145.2 million of buyout payments made by NU Enterprises in 2005 related to long-term wholesale power contracts that were terminated. Offsetting these items are higher regulatory refunds in 2006 as CL&P refunded amounts to its ratepayers to moderate the increase in CL&P's TSO rates that became effective on January 1, 2006 and a federal income tax payment of approximately $55 million related to NU's 2005 tax return which was made in the first quarter of 2006. No such federal income tax payment was made in the first quarter of 2005 related to NU's 2004 tax year. Other working capital items also contributed to this decrease.

The company expects net cash flows to increase and CL&P refunds to decline in the last quarter of 2006 as a result of a DPUC decision to terminate a $0.009 per kWh credit on customer bills to refund previous Competitive Transition Assessment (CTA) overrecoveries.

PSNH's operating cash flows are expected to decline in the last quarter of 2006 and thereafter as a result of a significant reduction in approved stranded cost recovery charge (SCRC) rates effective July 1, 2006 to an average rate of $0.0155 per kWh from the previous average rate of $0.0335 per kWh. That decline, which amounts to approximately $170 million annually, is the result of the completion of PSNH's recovery of its Part 3 non-securitized stranded costs as of June 30, 2006.

In November of 2005, NU entered into an amended revolving credit agreement that increased NU's credit line from $500 million to $700 million and extended the maturity date of the agreement to November 6, 2010. There were $81 million of borrowings outstanding under that agreement at September 30, 2006.

In the third quarter of 2006, NU Enterprises had additional cash inflows of approximately $100 million relating to the retail marketing business accounts receivable that were collected. The sale of the retail marketing business, which closed on June 1, 2006, will result in NU making three payments to Hess totaling $44 million. The first of those payments totaling approximately $11.5 million was made on June 1, 2006. The remaining payments of approximately $17.5 million and $15 million are scheduled to be made by December of 2006 and 2007, respectively.

On November 1, 2006, NU completed the sale of the competitive generation business to ECP. The sale resulted in cash inflows of approximately $1 billion. Taxes on the sale are expected to be approximately $490 million and will be paid in the first quarter of 2007, net of tax benefits arising from other activities. NU expects approximately $510 million of after-tax proceeds and will use the proceeds primarily to fund Utility Group capital expenditures and reduce short-term debt. The company expects that interest on the proceeds will continue to benefit earnings and liquidity for the remainder of 2006 and the first half of 2007.

Early in 2006, management indicated that it did not expect to issue equity before 2008. As a result of the $510 million of net proceeds from the sale of the competitive generation business noted above and new capital expenditure projections from 2007 through 2011, the company has reassessed its liquidity needs for the next five years. It expects that it will require approximately $5.5 billion through 2011 to fund its capital program and pay common and preferred dividends. The company projects that approximately $2.5 billion of those requirements will be funded through operating cash flows with the $3 billion balance funded through proceeds from the sale of the competitive generation business and external financings. Management expects that the vast majority of those financings will be debt issuances by the regulated utilities. To maintain 55 percent debt levels at the regulated utilities, the parent company will need to invest a considerable amount of additional equity into those businesses. Most of those funds will come from equity that has been returned to the parent company as a result of the November 1, 2006 sale of the competitive generation business. Management does not expect that the parent company will issue new equity in 2007 or 2008. A modest equity issuance in 2009 is possible, depending on the company's capital program and the company's future debt to equity targets. In the first nine months of 2006, NU invested $60 million of equity into CL&P, $5.5 million into PSNH, $28 million into WMECO, and $35 million into Yankee Gas.

NU's senior unsecured debt is rated Baa2, BBB- and BBB with a stable outlook by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch). If NU were to be downgraded to a sub-investment grade level by either Moody's or S&P, a number of Select Energy's contracts would require the posting of additional collateral in the form of cash or letters of credit (LOCs). Were NU's senior unsecured ratings to be reduced to sub-investment grade by either Moody's or S&P, Select Energy could, under its present contracts, be asked to provide approximately $152.3 million of collateral or LOCs to various unaffiliated counterparties and approximately $65.1 million to several independent system operators and unaffiliated local distribution companies (LDCs) at September 30, 2006. If such a downgrade were to occur, management believes NU would currently be able to provide this collateral.

On August 1, 2006, Moody's downgraded PSNH securities by one notch and changed the outlook to stable from under review - negative. The downgrade resulted from the lower cash flows Moody's forecast for PSNH following PSNH's full recovery of Part 3 stranded costs and resulting July 1, 2006 overall rate reduction. At Moody's new rating of Baa1, PSNH bonds continue to be at an investment grade level.

NU paid common dividends of $83.6 million in the first nine months of 2006, compared with $64.8 million in the first nine months of 2005. The higher level of dividend payments reflects a 7.7 percent increase in the NU quarterly dividend to $0.175 per share that was effective with the September 30, 2005 dividend and an increase in the number of outstanding shares as a result of the issuance of 23 million common shares in December of 2005. The higher level of dividend payments also reflects a 7.1 percent increase in the quarterly rate to $0.1875, effective with the September 29, 2006 common dividend. Management expects to continue its current policy of dividend increases, subject to the approval of the NU Board of Trustees and the company's future earnings and cash requirements.

Cash capital expenditures included on the condensed consolidated statements of cash flows and described in the liquidity section of this management's discussion and analysis do not include cost of removal, the allowance for funds used during construction (AFUDC), and the capitalized portion of pension expense or income. The increase in NU's cash capital expenditures for the nine months ended September 30, 2006, which totaled $600.3 million as compared to $521.5 million for the nine months ended September 30, 2005 was primarily the result of higher transmission capital expenditures, particularly at CL&P. For further information regarding capital expenditures reported by transmission, distribution and generation segments, see Note 12, "Segment Information."

Utility Group: In November of 2005, the Utility Group companies entered into an amended revolving credit agreement that maintained its $400 million credit line and extended the maturity date of their agreement to November 6, 2010. There were $197 million of borrowings outstanding under that agreement at September 30, 2006.

In addition to its revolving credit line, CL&P has an arrangement with a financial institution under which CL&P can sell up to $100 million of accounts receivable and unbilled revenues. At September 30, 2006, CL&P had sold $100 million to that financial institution. For more information regarding the sale of receivables, see Note 1F, "Summary of Significant Accounting Policies - Sale of Customer Receivables," to the condensed consolidated financial statements.

NU Enterprises: Currently, NU Enterprises' liquidity is impacted by both the amount of collateral it receives from other counterparties and the amount of collateral it is required to deposit with counterparties. From December 31, 2005 to September 30, 2006, the net positive impact on NU Enterprises' liquidity related to these items was approximately $50 million.

Most of the working capital and LOCs required by NU Enterprises are currently used to support the wholesale marketing business. As NU Enterprises' wholesale contracts expire or are exited, its liquidity requirements are expected to decline. However, the sale or assignment of additional long-term below market wholesale power contracts would likely require NU Enterprises to make significant payments to the counterparties in such transactions.

NU Enterprises Divestitures

NU has made significant progress in its strategic initiative to exit all of its competitive businesses. With the completion of the sale of its competitive generation business to ECP, NU has divested or sold a substantial portion of NU Enterprises' assets. As a result of these divestitures, NU's annual revenues are projected to decrease by approximately $2 billion from 2005 levels. NU will use sale proceeds to invest in its regulated businesses, reduce short-term debt and pay taxes related to the sale of the competitive generation business. An overview of this process is as follows:

Wholesale Marketing Business: Select Energy continues to serve its remaining PJM and New York wholesale sales contract obligations. By the end of 2006, if none of these obligations are divested, the remaining sales obligations are projected to be approximately 8 million megawatt-hours (MWh), down from approximately 22 million MWh as of March of 2005 when NU Enterprises announced it was exiting the wholesale marketing business. Select Energy has also taken steps to reduce the volatility of these obligations by hedging a portion of them. At this time, management cannot estimate at what value the obligations may be divested compared to the mark-to-market value currently recorded.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business to Hess, including all of its retail sales obligations and supply contracts. Under the terms of the agreement, Select Energy paid Hess approximately $11.5 million at closing and will pay an additional $32.5 million by the end of 2007, which is included in other current liabilities on the accompanying condensed consolidated balance sheet.

At September 30, 2006, Select Energy has net accounts receivable of approximately $6 million for services provided to customers prior to the June 1, 2006 sale of the retail marketing business, compared to approximately $70 million of net accounts receivable at June 30, 2006.

Select Energy is in the process of obtaining consents from its retail customers to assign contracts to Hess. Those contracts that have not been assigned are subject to administrative or back-to-back arrangements with Hess that mirror Select Energy's obligations.

In connection with the sale of the retail marketing business, NU has provided various indemnifications to Hess. Management does not expect that these indemnification obligations will have a significant impact on NU, and no liability has been recorded at September 30, 2006. See Note 7F, "Guarantees and Indemnifications," for further information regarding these indemnifications.

Competitive Generation Business: On July 24, 2006, NU reached an agreement with ECP to sell its 100 percent ownership in NGC and HWP's 146-MW Mt. Tom plant for $1.34 billion, which includes the assumption of $320 million of NGC debt. After receiving FERC and other approvals, the sale closed on November 1, 2006. NU will record an after-tax gain of approximately $300 million in the fourth quarter of 2006.

Energy Services Businesses: SECI-NH, including Reeds Ferry, and Woods Network were sold in November of 2005. In January of 2006, the Massachusetts service location of SECI-CT was sold. In April of 2006, NU Enterprises sold a portion of Woods Electrical. In May of 2006, SESI was sold.

NU Enterprises Items Retained: Items that have not yet either been sold or placed under contract to be sold by NU Enterprises are as follows:

- Five wholesale sales contracts in PJM (four of which expire in 2007 and one of which expires in 2008) and numerous related supply contracts which expire in 2007 and 2008;
- A long-term wholesale sales contract in New York which expires in 2013;
- Three power purchase contracts (two in New England and one in New York). Two contracts expire in 2007, and one expires in 2012;
- Remaining amounts and contingencies associated with a contract to complete a cogeneration facility; and
- Boulos and other contracts associated with the wind down of the energy services businesses.

In addition, provisions of the SESI purchase agreement require NU to indemnify the purchaser, Ameresco, for estimated costs to complete or modify specific construction projects above specified levels. See Note 7F, "Guarantees and Indemnifications," for further information regarding these guarantees.

See Note 4, "Assets Held for Sale and Discontinued Operations," for information regarding what businesses are held for sale and discontinued operations.

At September 30, 2006, $29.6 million in total assets and $24.3 million in total liabilities of SECI-NH, SECI-CT, Woods Network, Woods Electrical and SESI are retained by NU Enterprises. These assets and liabilities are primarily comprised of accounts receivable and unbilled revenues, accounts payable, long-term and short-term claims and debt.

Business Development and Capital Expenditures

Consolidated: NU's capital expenditures including cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $664.6 million in the first nine months of 2006, compared with $564.8 million in the first nine months of 2005. Included in these amounts are $636.1 million and $541.6 million related to the Utility Group. This increasing level of capital expenditures is caused primarily by the continuing need to improve the capacity and reliability of NU's regulated transmission system.

NU projects a total of $4.9 billion of Utility Group capital expenditures from 2007 through 2011. A summary of these estimated capital expenditures for the Utility Group transmission and distribution/generation businesses by company for 2007 through 2011, excluding approximately $18 million per year at the corporate service companies, is as follows (millions of dollars):

	Year						
	2006	2007	2008	2009	2010	2011	2007-2011 Totals
CL&P:							
Distribution	$ 206	$ 271	$ 260	$ 266	$ 270	$ 279	$ 1,346
Transmission	420	600	517	343	231	333	2,024
PSNH:							
Distribution and generation	105	128	134	112	128	148	650
Transmission	25	87	85	37	35	6	250
WMECO:							
Distribution	28	34	32	31	31	31	159
Transmission	10	17	54	45	43	42	201
Yankee Gas distribution	86	62	42	41	41	41	227
Totals - distribution and generation	$ 425	$ 495	$ 468	$ 450	$ 470	$ 499	$ 2,382

Totals - transmission	455	704	656	425	309	381	2,475
Totals	$ 880	$ 1,199	$ 1,124	$ 875	$ 779	$ 880	$ 4,857

Actual levels of capital expenditures could vary from the estimated amounts for the companies and periods above.

Utility Group:

CL&P: For the first nine months of 2006, CL&P's distribution capital expenditures totaled $152.5 million, compared with $187.8 million in the first nine months of 2005. In 2006, CL&P projects distribution capital expenditures of approximately $200 million.

CL&P's transmission capital expenditures totaled $291.5 million in the first nine months of 2006, compared with $146.2 million in the first nine months of 2005. The increase was primarily the result of increased spending on a 21-mile 345 kV transmission project between Bethel and Norwalk, Connecticut which was placed in service in October of 2006. In 2006, CL&P's transmission capital expenditures are projected to total approximately $420 million.

Transmission capital expenditures in Connecticut are focused primarily on four major transmission projects in southwest Connecticut. These projects include 1) the Bethel to Norwalk project, 2) a 69-mile Middletown to Norwalk 345 kV transmission project, 3) a related two-cable 115 kV underground project between Norwalk and Stamford, Connecticut (Glenbrook Cables), and 4) the replacement of the existing 138 kV cable between Connecticut and Long Island. Each of these projects has received approval from the Connecticut Siting Council (CSC) and the New England Independent System Operator (ISO-NE). Capital expenditures for these projects totaled $234.6 million in the first nine months of 2006 compared to $103.3 million in transmission capital expenditures in the first nine months of 2005.

Construction began in April of 2005 on a 21-mile 115 kV/345 kV line project between Bethel and Norwalk. As of late-September of 2006, construction on the Bethel to Norwalk project was 100 percent complete. The line was fully energized and went into service on October 12, 2006. The final cost of the project is expected to be approximately $340 million compared to a budget of $350 million. CL&P has capitalized $326.3 million through September 30, 2006.

On April 7, 2005, the CSC unanimously approved a proposal by CL&P and United Illuminating (UI) to build a 69-mile 345 kV transmission line from Middletown to Norwalk and CL&P has commenced site work. The project still requires CSC review of certain detailed construction plans, as well as United States Army Corps of Engineers approval to bury the line beneath certain navigable

rivers and the Connecticut Department of Environmental Protection (DEP) approvals. Except for a delay in obtaining the DEP permits allowing NU to cross certain water ways, the project is progressing as scheduled. The DEP permit delays are not expected to impact 2006 spending or the project in-service date. CL&P's portion of the project is estimated to cost approximately $1.05 billion and is expected to be completed by the end of 2009. This project is currently approximately 9 percent complete. At September 30, 2006, CL&P has capitalized $119.4 million associated with this project.

CL&P's construction of the Glenbrook Cables Project, two 9-mile 115 kV underground transmission lines between Norwalk and Stamford, was approved by the CSC on July 20, 2005 and approved by ISO-NE on August 3, 2005. The project is intended to respond to the growing electric demand in the area. Construction on the project, which is expected to cost $183 million, has begun. Management expects the lines to be in service in 2008. Through September 30, 2006, CL&P has capitalized $23.7 million associated with this project.

On October 1, 2004, CL&P and the Long Island Power Authority (LIPA) jointly filed plans with the DEP to replace a 138 kV undersea electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York, consistent with a comprehensive settlement agreement reached on June 24, 2004. CL&P and LIPA each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. Manufacturing of the cable has begun. The project in service date remains in 2008. Through September 30, 2006, CL&P has capitalized $13.9 million associated with this project.

In the fourth quarter of 2005, CL&P began construction of a new substation in Killingly, Connecticut, which will improve CL&P's 345 kV and 115 kV transmission systems in northeast Connecticut. The project is expected to be completed by the end of 2006 at a cost of approximately $32 million. At September 30, 2006, CL&P has capitalized $20.8 million associated with this project.

As part of a larger regional system plan, NU, ISO-NE and National Grid have begun planning an upgrade to the transmission system connecting Massachusetts, Rhode Island and Connecticut in a comprehensive study called the Southern New England Transmission Reliability (SNETR) Project. The parties are expected to identify a number of possible routes and configurations by 2007. NU and National Grid have not yet completed a detailed estimate of the total cost for the upgrade, but NU estimates that approximately $700 million of its approximately $2.4 billion transmission capital budget for 2007 through 2011 could be spent on this project.

Transmission Rate Base: At December 31, 2005, the Utility Group's transmission business rate base was approximately $600 million and is projected to be approximately $1.1 billion at December 31, 2006. Several factors may impact the Utility Group transmission business rate base amount, including the level and timing of transmission capital expenditures and transmission plant placed in service, regulatory approvals of various projects, and other factors.

Yankee Gas: In the first nine months of 2006, Yankee Gas' capital expenditures totaled $64 million, compared with $51.2 million in the first nine months of 2005. Yankee Gas is constructing a liquefied natural gas (LNG) storage and production facility in Waterbury, Connecticut, which will be capable of storing the equivalent of 1.2 billion cubic feet of natural gas. Construction of the facility began in March of 2005 and is expected to be completed in time for the 2007/2008 heating season. The facility, which is expected to cost $108 million, is currently approximately 85 percent complete. Yankee Gas has capitalized $81.5 million related to this project through September 30, 2006.

PSNH: In the first nine months of 2006, PSNH's capital expenditures totaled $93.7 million, compared with $123.2 million in the first nine months of 2005. The 2006 expenditures included $8.2 million in construction activities associated with PSNH's Northern Wood Power Project. Construction of the $75 million Northern Wood Power Project started in 2004. The new boiler is operating under coal and/or wood at various times as part of its start-up compliance adjustment and testing, with testing expected to be completed by the end of 2006. Through September 30, 2006, PSNH has capitalized $72.8 million related to this project.

Under the terms of the order issued by the New Hampshire Public Utilities Commission (NHPUC) approving the project, the costs of the project are subject to a prudence review by the NHPUC and the cost of the project was capped at $75 million. In the event the project's cost exceeds the $75 million cap, PSNH and its customers would each absorb half of the costs in excess of $75 million. While management currently believes that the project's cost will not exceed the $75 million cap and that PSNH's actions during the construction of the project have been prudent and consistent with industry practices, PSNH is unable to determine the impact, if any, of the NHPUC's prudence review of the project on PSNH's earnings or financial position.

WMECO: WMECO's capital expenditures totaled $31.8 million in the first nine months of 2006, compared with $31.5 million in the first nine months of 2005.

NU Enterprises: NU Enterprises capital expenditures totaled $18.9 million in the first nine months of 2006, compared with $14.2 million in the first nine months of 2005. The majority of the 2006 capital expenditures related to work performed for the selective catalytic reduction system installed at Mt. Tom, which was completed in June of 2006.

Transmission Rate Matters and FERC Regulatory Issues

Transmission - Wholesale Rates: Wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU's wholesale transmission revenues are collected through a combination of NU's LNS tariff and NU's regional network service (RNS) tariff. NU's LNS rate is reset on January 1 and June 1 of each year. NU's RNS rate is reset on June 1 of each year. Additionally, NU's LNS tariff provides for a true-up to actual costs, which ensures that NU's transmission business recovers its total transmission revenue requirements, including the allowed ROE.

On October 31, 2006, the FERC issued its decision on the ROE and incentives for the New England transmission owners. The FERC set the base ROE (before incentives) at 10.2 percent for the historical locked-in period of February 1, 2005 (when the New England RTO was activated) to October 31, 2006. The FERC also added 74 basis points for the true up of the 10-year treasury rate, bringing the going forward base ROE to 10.94 percent, effective on November 1, 2006. In addition, the FERC approved a 50 basis point adder for joining an RTO and approved a 100 basis point adder for all new transmission investment where the projects have been identified as necessary by the ISO-NE regional planning process. Both ROE adders for certain projects are retroactive to February 1, 2005.

On a going forward basis, NU's transmission capital program is largely comprised of regional infrastructure that is included within the regional planning process. Over 90 percent of the company's projected $2.4 billion capital program for 2007 through 2011 is expected to be in this category, and therefore earn at the 12.44 percent ROE.

The following is a summary of the ROEs for the applicable periods and facilities:

	LNS	**RNS**	**New ISO-NE Approved**
RTO - February 1, 2005 to October 31, 2006	10.2% (base)	10.7% (10.2% base plus 0.5% for RTO)	11.7% (10.7% plus 100 basis adder)
RTO - November 1, 2006 forward	10.94% (10.2% base plus 0.74% true-up)	11.44% (10.2% base plus 0.5% for RTO plus 0.74% true-up)	12.44% (11.44% plus 100 basis adder)

Prior to this decision, the base ROE being utilized in the calculation of LNS transmission wholesale rates was 12.8 percent. The ROE being utilized in the calculation of RNS transmission wholesale rates was 12.8 percent base plus a 50 basis point adder for joining an RTO, or a total of 13.3 percent, plus an additional 100 basis point adder on new regional transmission investment.

For purposes of revenue recognition, prior to this ROE decision, the transmission business assumed an ROE of 11.5 percent after the implementation of the RTO on February 1, 2005. As a result of the difference in the 12.8 percent base ROE and the 13.3 percent ROE being billed to LNS and RNS customers, respectively, and the 11.5 percent ROE assumed for earnings accruals and estimates through September 30, 2006, a $14.1 million liability for refunds has been accumulated and recorded.

The final amount of refunds and the impact on 2006 earnings will be determined and recorded when the calculation of the ROE for the historical locked-in period of February 1, 2005 to October 31, 2006 is completed in the fourth quarter of 2006. NU and the other RTO members are currently evaluating the FERC's decision to quantify its financial impacts and determine their next course of action. Management believes that any increase to the $14.1 million liability already recorded for the locked-in period will not be material to NU's financial statements.

Effective February 1, 2006, NU included 50 percent of construction work in progress (CWIP) for its four major southwest Connecticut transmission projects in its formula rate for transmission service (Schedule 21 - NU (LNS)). The new rates allow NU to collect 50 percent of the construction financing expenses while these projects are under construction.

On July 20, 2006, the FERC issued final rules promoting transmission investment through pricing reform that included up to 100 percent of CWIP in rate base, accelerated book depreciation, higher ROEs for belonging to an RTO, among others. The final rule identifies specific incentives the FERC will allow when justified in the context of specific rate applications. The burden remains on the applicant to illustrate through its filing that the incentives requested are just and reasonable and the project involved increases reliability or decreases congestion costs. Management views this rule to be positive and is currently evaluating these incentives relative to NU's overall transmission strategy.

On July 28, 2006, the FERC approved NU's proposal to allocate costs associated with the Bethel to Norwalk transmission project that are determined to be localized costs to all customers in Connecticut as all of Connecticut will benefit from the associated reduction in congestion charges. There are three load serving entities in Connecticut: CL&P, UI and the Connecticut Municipal Electrical Energy Cooperative (CMEEC). These customers would pay their allocated shares of the localized costs on a projected basis commencing on June 1, 2006, subject to true-up based on actual costs. UI has sought rehearing of the FERC decision.

On September 22, 2006, ISO-NE issued its determination letter with regard to CL&P's February 3, 2006 revised transmission cost allocation (TCA) application for the Bethel to Norwalk transmission project. The decision finds that $239.8 million of the total estimated cost of $357.2 million qualifies as pool-supported pool transmission facilities (PTF) costs, indicating $117.4 million of total estimated costs that will be localized. If the $357.2 million estimated cost is lower, the amounts related to pool supported PTF costs and localized costs will be proportionally reduced. CL&P has 60 days from the date of the determination letter to challenge this decision.

Legislative Matters

Connecticut:

Act Concerning Energy Independence: On September 13, 2006, under the provisions of Connecticut's Act Concerning Energy Independence adopted in 2005, the DPUC issued an interim decision approving its request for proposals to solicit new generating capacity or demand-side management, which could provide for contracts for up to 15 years that the distribution companies would be required to enter into. The structure of these arrangements will vary and may include payment for the difference between a fixed contract price and the ISO-NE wholesale capacity market price. These arrangements may include optionality in pricing. The DPUC plans to request bids from respondents on December 13, 2006. Winning bids will be selected by April of 2007 and executed contracts will be approved no later than November 8, 2007 in a separate contested proceeding. The DPUC will determine the amount and duration of any such contracts.

Energy Summit Meetings: During the summer of 2006, the Connecticut legislature held public energy summit meetings to address the problems of higher energy costs affecting the state. No legislative action has resulted from these sessions but further initiatives may impact CL&P.

Utility Group Regulatory Issues and Rate Matters

Transmission - Retail Rates: A significant portion of the NU transmission business revenue comes from ISO-NE charges to the distribution businesses of CL&P, PSNH and WMECO. The distribution businesses recover these costs through the retail rates that are charged to their retail customers. In 2005, CL&P began tracking its retail transmission revenues and expenses. WMECO implemented its retail transmission tracker and rate adjustment mechanism in January of 2002 as part of its 2002 rate change filing. PSNH does not currently have a retail transmission rate tracking mechanism, but the company requested such a mechanism in its 2006 energy delivery rate case.

Forward Capacity Market: On March 6, 2006, ISO-NE and a broad cross-section of critical stakeholders from around the region, including CL&P, PSNH and Select Energy, filed a comprehensive settlement agreement at the FERC proposing a forward capacity market (FCM) in place of the previously proposed locational installed capacity (LICAP), an administratively determined electric generation capacity pricing mechanism. The settlement agreement provided for a fixed level of compensation to generators from December 1, 2006 through May 31, 2010 without regard to location in New England, and annual forward capacity auctions, beginning in 2008, for the 1-year period ending on May 31, 2011, and annually thereafter. According to preliminary estimates, FCM would require the operating companies to pay approximately the following amounts from December 1, 2006 through December 31, 2009: CL&P - $470 million; PSNH - $80 million; and WMECO - $100 million. CL&P, PSNH and WMECO expect to recover these costs from their customers. On June 16, 2006, the FERC accepted the settlement agreement which is expected to be implemented by December 1, 2006. Several parties have sought rehearing of this issue by the FERC, which was denied by the FERC on October 31, 2006.

Connecticut - CL&P:

Income Taxes: In 2000, CL&P requested from the IRS a PLR regarding the treatment of unamortized UITC and EDIT related to generation assets that were sold. On April 18, 2006, the IRS issued a PLR to CL&P regarding the treatment of UITC and EDIT. EDIT are temporary differences between book and taxable income that were recorded when the federal statutory tax rate was higher than it is now or when those differences were expected to be resolved. The PLR holds that it would be a violation of tax regulations if the EDIT or UITC is used to reduce customers' rates following the sale of the generation assets. CL&P's UITC and EDIT balances related to generation assets that have been sold totaled $59 million and $15 million, respectively, and $74 million combined. CL&P was ordered by the DPUC to submit the PLR to the DPUC within 10 days of issuance and retain the UITC and EDIT in their existing accounts pending its receipt and review of the PLR. On July 27, 2006, the DPUC determined that the UITC and EDIT amounts were no longer required to be held in their existing accounts. As a result of this determination, the $74 million balance was reflected as a reduction to CL&P's third quarter 2006 income tax expense with an increase to CL&P's earnings by the same amount.

Procurement Fee Rate Proceedings: CL&P is currently allowed to collect a fixed procurement fee of 0.50 mills per kWh from customers who purchase TSO service through 2006. One mill is equal to one-tenth of one cent. That fee can 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 portion (incentive portion) of the procurement fee and requested approval of $5.8 million for its 2004 incentive payment. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology proposed by CL&P and authorized payment of the $5.8 million incentive fee. A final decision, which had been scheduled for December 28, 2005, was delayed by the DPUC and the DPUC re-opened the docket to allow the OCC to submit additional testimony. Management continues to believe that recovery of the $5.8 million regulatory asset recorded related to CL&P's 2004 incentive payment, which was reflected in 2005 earnings, is probable. No amounts have been recorded related to the 2005 incentive portion of CL&P's procurement fee.

The legislation allowing collection of a procurement fee expires on January 1, 2007. As a result, management does not expect CL&P to earn a procurement fee relating to customers purchasing energy from CL&P beyond December 31, 2006.

Streetlighting Decision: On June 30, 2005, the DPUC issued a final decision which required CL&P to recalculate all previously issued refunds (except for the towns of Stamford and Middletown) utilizing applicable approved pre-tax cost of capital rates. The net impact in 2005 was an additional $4.1 million of pre-tax reserve which was recorded. On August 11, 2005, CL&P filed an appeal of this decision in the Connecticut Superior Court. On August 29, 2006, the court issued its final decision on CL&P's appeal. In the third quarter of 2006, this decision resulted in an after-tax reduction of $0.6 million of the streetlighting refund reserve established.

Distribution Rates: In its December 2003 rate case decision, the DPUC allowed CL&P to increase distribution rates annually from 2004 through 2007. A $25 million distribution rate increase took effect on January 1, 2005, an additional $11.9 million distribution rate increase took effect on January 1, 2006, and another $7 million distribution rate increase is due to take effect on January 1, 2007.

On August 4, 2006, CL&P notified Governor Rell and the DPUC that it intends to postpone filing a distribution rate case until mid-2007 for rates effective on January 1, 2008.

FMCC Filings: On February 1, 2006, CL&P filed with the DPUC its annual federally mandated congestion cost (FMCC) reconciliation filing for the year ended December 31, 2005. No change to the current FMCC rate was proposed. On October 10, 2006, the DPUC issued a draft decision approving the 2005 FMCC reconciliation and agreed that no rate changes were necessary for 2006. The FMCC rates will change on January 1, 2007 following a filing by CL&P.

On August 1, 2006, CL&P filed with the DPUC its semi-annual FMCC reconciliation filing to document actual FMCC and generation service charge (GSC) revenues and expenses for the period January 1, 2006 through June 30, 2006 and projected costs for the period July 1, 2006 through December 31, 2006. The filing recommends that the current FMCC rates remain in effect for the remainder of 2006. The DPUC has not yet established a schedule for review of this filing.

Standard Service Procurement: On June 21, 2006, the DPUC approved a proposal by CL&P to issue requests for proposal (RFPs) periodically for periods from three months to three years to layer the standard service full requirements supply contracts to mitigate market volatility for its residential and lower use commercial and industrial customers. Additionally, the DPUC approved the issuance of RFPs for supplier of last resort service for larger commercial and industrial customers every six months. Previously, all of CL&P's residential, commercial and industrial requirements, regardless of customer size, were bid together. The DPUC's decision also provides for enhanced access to the RFP materials, bids and other data during the RFP process.

In September of 2006, CL&P received and awarded bids for standard service for a portion of standard service for 2007 and 2008. CL&P received final bids for 2007 on October 30, 2006. CL&P will receive bids in 2007 for standard service for remaining 2007 requirements and for some requirements in 2008. CL&P also received and awarded bids in September of 2006 for its supplier of last resort service for its larger commercial and industrial customers for January of 2007 through June of 2007.

Connecticut - Yankee Gas:

Purchased Gas Adjustment: On September 9, 2005, the DPUC issued a draft decision regarding Yankee Gas Purchased Gas Adjustment (PGA) clause charges for the period of September 1, 2003 through August 31, 2004. The draft decision disallowed approximately $9 million in previously recovered PGA revenues associated with two separate Yankee Gas unbilled sales and revenue adjustments. At the request of Yankee Gas, the DPUC reopened the PGA hearings on September 20, 2005 and requested that Yankee Gas file supplemental information regarding the two adjustments. Yankee Gas complied with this request. The DPUC issued a new decision on April 20, 2006 requiring an audit of Yankee Gas' PGA accounting methods and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. In a recent draft decision regarding Yankee Gas PGA charges for the period September 1, 2004 through August 31, 2005, an additional $2 million related to previously recovered revenues was also identified, bringing the total maximum amount at issue with regard to PGA clause charges under audit to $11 million.

The DPUC has hired a consulting firm who has begun an audit of Yankee Gas' PGA accounting methods. The company expects that the audit will be completed by the end of 2006. Management believes the unbilled sales and revenue adjustments and resultant charges to customers through the PGA clause for both periods were appropriate. Based on the facts of the case and the supplemental

information provided to the DPUC, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved, and has not reserved for any loss.

New Hampshire:

SCRC Reconciliation and SCRC Rates: On May 1, 2006, PSNH filed its 2005 SCRC reconciliation with the NHPUC. On October 25, 2006, PSNH, the NHPUC staff and the Office of Consumer Advocate (OCA) filed a settlement agreement with the NHPUC which resolved all outstanding issues associated with the 2005 SCRC reconciliation. Management believes that this settlement agreement will not have a material effect on PSNH's financial statements. The NHPUC held hearings on October 26, 2006, and currently management does not have a specific date when the NHPUC's order will be issued.

On September 22, 2006, PSNH filed a petition with the NHPUC requesting a change in its SCRC rate for the period January 1, 2007 through December 31, 2007. PSNH requested that the NHPUC review and approve the underlying data in this filing. PSNH expects to petition the NHPUC in November of 2006 for a specific SCRC rate based upon current energy market data.

ES Rates: On September 8, 2006, PSNH filed a petition with the NHPUC requesting a change in its default energy service (ES) rate for the period January 1, 2007 through December 31, 2007. Consistent with previous filings, PSNH requested that the NHPUC review and approve the underlying operational data in this filing and not the specific ES rate. PSNH expects to petition the NHPUC in November of 2006 for a specific ES rate based upon current energy market data.

Coal Procurement Docket: During the second quarter of 2006, the NHPUC opened a docket to review PSNH's coal procurement and coal transportation policies and procedures. PSNH is responding to data requests from the NHPUC's outside consultant. While management believes its coal procurement and transportation policies and procedures are prudent and consistent with industry practice, it is unable to determine the impact, if any, of the NHPUC's review on PSNH's earnings or financial position.

Massachusetts:

Transition Cost Reconciliation: On October 24, 2006 the DTE issued its decision in WMECO's 2003 and 2004 transition cost reconciliation filing. The DTE decision in this combined docket resolves all outstanding issues through

2004 for transition, retail transmission, standard offer and default service costs/revenues and did not have a significant impact on WMECO's earnings or financial position.

WMECO filed its 2005 transition cost reconciliation with DTE on March 31, 2006. The DTE has not yet reviewed this filing or issued a schedule for review and the timing of a decision is uncertain. Management does not expect the outcome of the DTE's review to have a significant adverse impact on WMECO's earnings or financial position.

Annual Rate Change Filing: On October 19, 2006, WMECO filed with the DTE a settlement agreement among WMECO, the Massachusetts Attorney General and two other parties that included distribution rate increases of $1 million beginning on January 1, 2007 and an additional $3 million distribution rate increase beginning on January 1, 2008. Also included in the settlement agreement are cost tracking mechanisms for pension and other postretirement benefit costs, uncollectible amounts related to energy costs, and recovery of certain capital improvements needed for system reliability. The settlement agreement includes an earnings sharing mechanism that will equally share with customers any earnings in excess of an actual ROE of 12 percent and any shortfall below an actual ROE of 8 percent during the two-year settlement period. The determination of any excess or shortfall would be done annually, with any such excess being recorded as a regulatory liability and any such shortfall being recorded as a regulatory asset. The time period for the refund of any excess or collection of any shortfall would ultimately be determined by the DTE. Under this settlement agreement, management expects that a return on capital investment of between 9 percent and 10 percent annually is achievable for WMECO. The settlement agreement must be approved by the DTE.

Deferred Contractual Obligations

CYAPC: On July 1, 2004, CYAPC filed with the FERC for recovery seeking to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection by CYAPC beginning on February 1, 2005, subject to refund.

On June 10, 2004, the DPUC and the OCC filed a petition with the FERC seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. The FERC rejected the DPUC's and OCC's petition, whereupon the DPUC filed an appeal of the FERC's decision with the D.C. Circuit Court of Appeals (Court of Appeals).

On August 15, 2006, CYAPC, the DPUC, the OCC and Maine state regulators filed a settlement agreement with the FERC. The settlement agreement, if approved, disposes of the pending litigation at the FERC and the Court of Appeals, among other issues.

Under the terms of the settlement agreement, the parties have agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars), taking into account actual spending through 2005 and the current estimate for completing decommissioning and long-term storage of spent fuel, a gross domestic product escalator of 2.5 percent for costs incurred after 2006, and a 10 percent contingency factor for all decommissioning costs. Annual collections at the revised level would begin in 2007, and are reduced from the $93 million originally requested for years 2007 through 2010. Revised annual collections begin at $37 million in 2007 and reach $46 million in 2015.

The reduction to annual collections is achieved by extending the collection period by 5 years through 2015, reflecting the proceeds from a settlement agreement with Bechtel Power Corporation (Bechtel) by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. Additionally, the settlement agreement includes an incentive that reduces collections up to $10 million during years 2007 to 2010, but allows CYAPC to recoup up to $5 million of these collections, depending on the date that the Nuclear Regulatory Commission amends CYAPC's license permitting fuel storage-only operations. The settlement agreement also contains various mechanisms for true-ups and adjustments related to decommissioning and allows CYAPC to resume reasonable payment of dividends to its shareholders. The FERC staff has filed in support of the settlement agreement and no party has objected to the settlement agreement. Management expects that the FERC will rule on the settlement agreement by the end of 2006.

The settlement agreement also required CYAPC to forego collection of a $10 million regulatory asset and write this amount off. Because the contingency surrounding this regulatory asset existed at June 30, 2006, the write-off was recorded in the second quarter. NU recorded a total after-tax write-off of $3 million ($2.1 million, $0.3 million and $0.6 million for CL&P, PSNH and WMECO, respectively) for its 49 percent ownership share of this charge.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal no later than January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In 2004, a trial was conducted in the Court of Federal Claims in which 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 Yankee Companies had claimed actual damages for the same period as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed wet pool operating expenses. The Court of Federal Claims found that Yankee Companies would have incurred the disallowed expenses notwithstanding the DOE breach given the DOE's probable rate of acceptance of spent nuclear fuel had a depository been available.

The Court of Federal Claims, following precedent set in another case, also did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. The Yankee Companies believe they will have the opportunity in future lawsuits to seek recovery of actual damages incurred in the years following 2001/2002. The Yankee Companies expect the DOE to appeal the decision. 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 collectively own 49 percent of CYAPC, 38.5 percent of YAEC and 20 percent of MYAPC, and their aggregate share of these damages would be $44.7 million. Their respective shares of these damages would be as follows: CL&P: $29 million; PSNH: $7.8 million; and WMECO: $7.9 million. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery or the credit to future storage costs that may be realized in connection with this matter.

NU Enterprises

Merchant Energy Business: At September 30, 2006, the merchant energy business includes Select Energy's wholesale marketing business, 1,442 MW of generation assets, including 1,296 MW of primarily pumped storage and hydroelectric generation assets at NGC and 146 MW of coal-fired generation assets at HWP related to Mt. Tom, and NGS, which NU Enterprises is exiting. Prior to the March 2005 decision to exit the wholesale marketing business, this business also included full requirements sales to LDCs and bilateral sales to other load-serving counterparties. These sales were sourced by the generation assets and an inventory of energy contracts. The sale of the company's 100 percent ownership in NGC and HWP's 146-MW Mt. Tom plant closed on November 1, 2006.

Energy Services Business: At September 30, 2006, the energy services businesses include the operations of Boulos, which is not currently being actively marketed, and SECI-CT, which is a division of SECI. SECI-CT is in the process of completing work on several of its contracts.

Intercompany Transactions: There were no CL&P TSO purchases from Select Energy in the third quarters of 2006 or 2005. Other energy purchases between CL&P and Select Energy totaled $4.5 million in the first nine months of 2006 and $41 million in the first nine months of 2005. WMECO had $0.6 million in purchases from Select Energy in the first nine months of 2006, compared with $35.9 million in the first nine months of 2005.

Select Energy purchases from NGC and Mt. Tom represented $103.7 million and $40.7 million for the three and nine months ended September 30, 2006, respectively. These amounts totaled $113.6 million and $39.7 million for NGC and Mt. Tom, respectively, for the three and nine months ended September 30, 2005. As a result of the sale of NGC and Mt. Tom to ECP on November 1, 2006, Select Energy's purchases from those facilities ended.

Risk Management: Until the exit from the merchant energy business is completed, NU Enterprises will continue to be exposed to various market risks which could negatively affect the value of its remaining business. This business includes its remaining portfolio of wholesale energy contracts. Market risk at this point is comprised of the possibility of adverse energy commodity price movements and unexpected load ingress or egress, which would affect the volumes and values of these contracts.

NU Enterprises manages these and associated operating risks through detailed operating procedures and an internal review committee. A separate, parent-level committee, the Risk Oversight Council (ROC), meets monthly and upon the occurrence of specific portfolio-triggered events with NU Enterprises' leadership to review the conformity of NU Enterprises' activities, commitments and exposures to NU's risk parameters.

Wholesale Contracts: As a result of NU's decision to exit the wholesale marketing business, certain wholesale energy contracts previously accounted for under accrual accounting were required to be marked-to-market in the first quarter of 2005. Existing energy trading contracts have been and will continue to be marked-to-market with changes in fair value reflected in the statements of income/(loss).

At September 30, 2006 and December 31, 2005, Select Energy had wholesale derivative assets and derivative liabilities as follows:

(Millions of Dollars)		**September 30, 2006**		**December 31, 2005**
Current wholesale derivative assets	$	58.2	$	256.6
Long-term wholesale derivative assets		26.3		103.5
Current wholesale derivative liabilities		(116.4)		(369.3)
Long-term wholesale derivative liabilities		(114.4)		(220.9)
Total portfolio	$	(146.3)	$	(230.1)

Numerous factors could either positively or negatively affect the realization of the net fair value amounts in cash. These include the amounts paid or received to divest some or all of these contracts, the volatility of commodity prices until the contracts are divested, the outcome of future transactions, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all wholesale positions to be marked-to-market at the end of each business day and segregating responsibilities between the individuals actually transacting (front office) and those confirming the trades (middle office). The determination of the portfolio's fair value is the responsibility of the middle office independent from the front office.

The methods used to determine the fair value of wholesale energy contracts are identified and segregated in the table of fair value of contracts at September 30, 2006 and December 31, 2005. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange (NYMEX) futures, swaps and options 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 or natural gas, 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. Currently, Select Energy has a contract for which a portion of the contract's fair value is determined based on a model or other valuation method. The model utilizes natural gas prices and a conversion factor to electricity. Broker quotes for electricity at locations for which Select Energy has entered into transactions are generally available through the year 2010. For all natural gas positions, broker quotes extend through 2011 and are calculated for 2012 and 2013 based on discounted 2011 prices.

Generally, valuations of short-term 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 contracts are less certain. Accordingly, there is a risk that contracts will not be realized at the amounts recorded.

As of September 30, 2006 and December 31, 2005, the sources of the fair value of wholesale contracts and for the three and nine months ended September 30, 2006 and 2005, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Wholesale Contracts at September 30, 2006**			
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	$ 6.1	$ (9.3)	$ (1.9)	$ (5.1)
Prices provided by external sources	(64.4)	(45.8)	(5.1)	(115.3)
Models based	-	3.7	(29.6)	(25.9)
Totals	$ (58.3)	$ (51.4)	$ (36.6)	$ (146.3)

	Fair Value of Wholesale Contracts at December 31, 2005			
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	$ 31.3	$ 19.1	$ -	$ 50.4
Prices provided by external sources	(147.5)	(94.7)	(2.8)	(245.0)
Models based	0.7	(10.3)	(25.9)	(35.5)
Totals	$ (115.5)	$ (85.9)	$ (28.7)	$ (230.1)

	Three Months Ended September 30, 2006	**Nine Months Ended September 30, 2006**
	Total Portfolio Fair Value	**Total Portfolio Fair Value**
Fair value of wholesale contracts outstanding at beginning of period	$ (155.7)	$ (230.1)
Contracts realized or otherwise settled during the period	7.5	100.9
Changes in fair value recorded:		
Wholesale contract market changes, net	4.6	(14.1)
Fuel, purchased and net interchange power	0.1	0.1

Operating revenues	(2.8)	(3.1)
Fair value of wholesale contracts outstanding at end of period	$ (146.3)	$ (146.3)

Select Energy has a wholesale non-derivative generation purchase contract expiring in 2012. At September 30, 2006, this contract had a positive fair value in excess of $100 million, which as a non-derivative contract has not been recorded in the financial statements. Based on the current value of this contract, when combined with the net wholesale derivative contract portfolio that has been marked-to-market at September 30, 2006 with a value of negative $146.3 million, management believes, under present conditions, that the total cash cost to exit the remaining wholesale marketing business to be significantly less than $100 million.

Changes in the fair value of wholesale contracts that were marked-to-market as a result of the decision to exit the wholesale business totaled a positive $4.6 million and a negative $14.1 million for the three and nine months ended September 30, 2006, respectively, and are recorded as wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss). Changes in the fair value of natural gas contracts and a generation purchase contract in New York totaling a positive $0.1 million in both the three and nine months ended September 30, 2006, are recorded as fuel, purchased and net interchange power, while changes in fair value of contracts formerly designated as trading totaling a negative $2.8 million and $3.1 million for the three and nine months ended September 30, 2006, respectively, are recorded as revenue on the condensed consolidated statements of income/(loss).

Retail Marketing Activities: Select Energy sold its retail marketing business to Hess on June 1, 2006.

At September 30, 2006, Select Energy had derivative assets and liabilities totaling $0.9 million and $2.8 million, respectively, related to back-to-back agreements for electric and gas contracts on which Select Energy has not yet received customer consents to transfer to Hess. These derivative assets and liabilities are classified as assets held for sale and liabilities of assets held for sale, respectively, on the accompanying condensed consolidated balance sheets.

At September 30, 2006 and December 31, 2005, Select Energy had retail derivative assets and derivative liabilities as follows:

(Millions of Dollars)	September 30, 2006		December 31, 2005	
Current retail derivative assets	$	0.9	$	55.0
Long-term retail derivative assets		-		12.9
Current retail derivative liabilities		(2.6)		(27.2)
Long-term retail derivative liabilities		(0.3)		0.4
Total		(2.0)		41.1
Retail hedges		-		(24.1)
Mark-to-market portfolio	$	(2.0)	$	17.0

The methods used to determine the fair value of retail energy contracts are identified and segregated in the table of fair value of contracts at September 30, 2006 and December 31, 2005. 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, including bilateral contracts for the purchase or sale of electricity or natural gas, and are marked to the mid-point of bid and ask market prices.

At September 30, 2006 and December 31, 2005, the sources of the fair value of retail energy contracts and for the three and nine months ended September 30, 2006, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	Fair Value of Retail Sourcing Contracts at September 30, 2006					
Sources of Fair Value	Maturity Less than One Year		Maturity of One to Four Years		Total Fair Value	
Prices provided by external sources	$	(1.7)	$	(0.3)	$	(2.0)
Totals	$	(1.7)	$	(0.3)	$	(2.0)

	Fair Value of Retail Sourcing Contracts at December 31, 2005					
Sources of Fair Value	Maturity Less than One Year		Maturity of One to Four Years		Total Fair Value	
Prices actively quoted	$	(8.8)	$	-	$	(8.8)
Prices provided by external sources		25.8		-		25.8
Totals	$	17.0	$	-	$	17.0

	Three Months Ended September 30, 2006 Total Portfolio Fair Value	Nine Months Ended September 30, 2006 Total Portfolio Fair Value
Fair value of retail contracts outstanding at beginning of period	$ 1.6	$ 17.0
Contracts realized or otherwise settled during the period	-	(5.8)
Changes in fair value recorded:		
Transferred to Hess	(3.6)	43.0
Other operating expenses	-	(47.6)
Fuel, purchased and net interchange power	-	(8.6)
Fair value of retail contracts outstanding at end of period	$ (2.0)	$ (2.0)

Changes in the fair value of retail contracts until the June 1, 2006 sale of the retail business totaling a negative $47.6 million were recorded in other operating expenses on the accompanying condensed consolidated statements of income/(loss). Any changes in fair value subsequent to the sale are recorded as other current liabilities and other deferred credits. During the three and nine months ended September 30, 2006, a negative $3.6 million and a positive $43 million of derivatives were transferred to Hess as a result of the sale of the retail marketing business. In connection with the decision to exit the wholesale marketing business in March of 2005, Select Energy identified certain contracts previously designated as wholesale and redesignated them to support its retail marketing business. For the nine months ended September 30, 2006, $8.6 million of charges were recorded in fuel, purchased and net interchange power on the condensed consolidated statements of income/(loss) related to these contracts.

Competitive Generation Activities: Until the time of sale, the competitive generation assets owned by NU Enterprises were subject to certain operational risks, including but not limited to the length of scheduled and non-scheduled outages, bidding and scheduling with various ISOs, environmental issues and fuel costs. Competitive generation activities were also subject to various federal, state and local regulations. These risks may result in changes in the anticipated gross margins realized from competitive generation portfolio activities.

For the nine months ended September 30, 2006, the Mt. Tom plant had an availability factor of 87.9 percent, while the 1,080 MW Northfield Mountain facility had an availability factor of 88.2 percent. The approximately 200 MW of hydroelectric units had an aggregate availability factor of 93.3 percent. Total competitive generation was approximately 2 million MWhs through September 30, 2006. The Mt. Tom plant generated approximately 0.7 million MWhs in the first nine months of 2006. NGC's Northfield Mountain facility generated approximately 0.7 million MWhs and other hydroelectric facilities generated approximately 0.6 million MWhs for the nine months ended September 30, 2006. Conventional hydroelectric output benefited from above average rainfall.

The competitive generation business includes third party derivative generation related sales contracts (third party generation contracts) and physical generation from NGC and HWP (physical generation). At September 30, 2006 and December 31, 2005, Select Energy had generation derivative assets and derivative liabilities as follows:

(Millions of Dollars)		**September 30, 2006**		**December 31, 2005**
Current generation derivative assets	$	4.1	$	9.2
Long-term generation derivative assets		-		-
Current generation derivative liabilities		(3.9)		(5.1)
Long-term generation derivative liabilities		(2.5)		(15.5)
Total portfolio	$	(2.3)	$	(11.4)

Certain generation derivatives are included in liabilities of assets held for sale. See Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements.

The methods used to determine the fair value of generation contracts are identified and segregated in the table of fair value of contracts at September 30, 2006 and December 31, 2005. A description of each method is as follows: 1) prices actively quoted primarily represent exchange traded futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards, including bilateral contracts for the purchase or sale of electricity and are marked to the mid-point of bid and ask market prices.

At September 30, 2006 and December 31, 2005, the sources of the fair value of generation contracts and for the three and nine months ended September 30, 2006, the changes in fair value of these contracts are included in the following tables:

(Millions of Dollars)	**Fair Value of Generation Contracts at September 30, 2006**

Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Total Fair Value
Prices actively quoted	$ 2.7	$ -	$ 2.7
Prices provided by external sources	(2.5)	(2.5)	(5.0)
Totals	$ 0.2	$ (2.5)	$ (2.3)

	Fair Value of Generation Contracts at December 31, 2005		
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Total Fair Value
Prices actively quoted	$ (1.8)	$ -	$ (1.8)
Prices provided by external sources	5.9	(15.5)	(9.6)
Totals	$ 4.1	$ (15.5)	$ (11.4)

	Three Months Ended September 30, 2006 Total Portfolio Fair Value	Nine Months Ended September 30, 2006 Total Portfolio Fair Value
Fair value of competitive generation contracts outstanding at beginning of period	$ (12.9)	$ (11.4)
Contracts realized or otherwise settled during the period	1.6	(9.9)
Changes in fair value recorded:		
Discontinued operations	8.5	12.8
Wholesale contract market changes, net	0.2	(0.8)
Operating revenues	0.3	7.0
Fair value of competitive generation contracts outstanding at end of period	$ (2.3)	$ (2.3)

Changes in the fair value of generation contracts that became marked-to-market as a result of the decision to exit the remainder of the NU Enterprises' businesses totaled a positive $8.5 million and $12.8 million for the three and nine months ended September 30, 2006, respectively, which is recorded in discontinued operations on the accompanying condensed consolidated statements of income/(loss). These contracts are being sold along with the generation assets. Changes in fair value of the remaining generation contracts that were marked-to-market as a result of the decision to exit the wholesale marketing business totaled a positive $0.2 million and a negative $0.8 million for the three and nine months of 2006, respectively, and are recorded as wholesale contract market changes, net on the accompanying condensed consolidated statements of income/(loss). Changes in the fair value of energy contracts that remain in continuing operations totaling a positive $0.3 million for the three months ended September 30, 2006 and $7 million for the nine months ended September 30, 2006 are recorded as revenues on the condensed consolidated statements of income/(loss).

For further information regarding Select Energy's derivative contracts, see Note 5, "Derivative Instruments," to the condensed consolidated financial statements.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in establishing credit limits prior to Select Energy's entering into contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions. At September 30, 2006, Select Energy's counterparty credit exposure to wholesale and trading counterparties was approximately 14 percent collateralized or rated BBB- or better and approximately 86 percent was non-rated. The composition of Select Energy's credit portfolio has shifted from being largely investment grade-rated to being mostly non-rated. This is largely due to the divestiture of Select Energy's New England and retail portfolios. The bulk of the non-rated credit exposure is comprised of one counterparty (97 percent of total) that is a creditworthy, non-rated public entity. Select Energy was provided $0.2 million and $28.9 million of counterparty deposits at September 30, 2006 and December 31, 2005, respectively. For further information, see Note 1J, "Summary of Significant Accounting Policies - Counterparty Deposits," to the condensed consolidated financial statements.

Critical Accounting Policies and Estimates Update

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 the financial statements of NU. Management communicates to and discusses with NU's Audit Committee of the Board of Trustees those accounting policies and estimates it believes are most critical.

Pension Plan Curtailment: NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees. For the Pension Plan, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the resulting change in the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost could have a material impact on NU's condensed consolidated financial statements.

In December of 2005, a new program was approved providing a benefit for new non-union employees hired on and after January 1, 2006 allowing these employees to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. Non-union employees actively employed on December 31, 2005 were given the choice in 2006 to elect to continue participation in the Pension Plan or instead receive a new employer contribution under the 401(k) Savings Plan effective on January 1, 2007. In 2006, this benefit was also provided to certain PSNH union employees. If the new benefit was elected, their accrued pension liability in the Pension Plan will be frozen as of December 31, 2006. These employees were required to make this election by August of 2006. The approval of the new plan resulted in the recording of an estimated pre-capitalization, pre-tax curtailment expense of $6.2 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Management estimated the amount of the curtailment expense associated with this change based upon actuarial calculations and certain assumptions, including the expected level of transfers to the new 401(k) benefit.

Because the predicted level of elections of the new benefit did not occur, NU recorded adjustments to both the curtailment and 2006 pension expense in the third quarter of 2006. The increase in pension expense reflects interest on the increased projected benefit obligation and amortization of increased actuarial gains and losses resulting from the inclusion of additional employees in Pension Plan calculations. These adjustments resulted in a pre-capitalization, pre-tax reduction in the curtailment expense of $3.6 million and a pre-capitalization, pre-tax increase in pension expense of $2.7 million.

In addition, in the third quarter of 2006, management changed the vesting provisions of 401(k) benefit from a five-year to three-year period as a result of the Pension Protection Act signed by the President on August 17, 2006. Employees who have worked for NU for less than five years will be given another chance to transfer to the new 401(k) benefit in the fourth quarter of 2006. The impact of this change is not expected to be material.

Income Taxes: Income tax expense is calculated in each reporting period in each of the jurisdictions in which NU operates. This process involves estimating actual current tax expense or benefit as well as the income tax impact of temporary differences resulting from differing treatment of items, such as timing of the deduction and expenses, for tax and book accounting purposes. 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 NU's segments. Adjustments made to income tax estimates can significantly affect NU's condensed consolidated financial statements.

The estimates that are made by management in order to record income tax expense are compared each year to the actual tax amounts included on NU's income tax returns as filed. The income tax returns are filed in the fall of each year for the previous tax year. Management adjusted NU's tax reserves to reflect the difference in the actual tax return amounts being compared to the previous year end estimated tax expense amounts. Recording these tax reserve adjustments resulted in a positive/(negative) impact on NU's earnings in the third quarter of 2006 and 2005 as follows (in millions):

	2006	**2005**
CL&P	$ 2.0	$ (0.3)
PSNH	0.1	1.3
WMECO	0.1	0.2
NU Enterprises	2.9	(1.0)
Other companies	(0.3)	(0.4)
Total	$ 4.8	$ (0.2)

Truing up income tax amounts between the condensed consolidated financial statements and the income tax returns is an annual process.

Goodwill Impairment Testing: NU conducts goodwill impairment testing as of October 1st 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.

Performance of the annual testing of current goodwill balances commenced in October of 2006.

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.

Discontinued Operations Presentation: In order for discontinued operations treatment to be appropriate, management must conclude that there is a component of a business that is "held for sale" in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and that it meets the criteria for discontinued operations. At September 30, 2006, based on the status of exiting the NU Enterprises businesses, management concluded that discontinued operations presentation is appropriate for NGC, Mt. Tom, SESI, a portion of Woods Electrical, SECI-NH and Woods Network. The retail marketing business, which is held for sale, is not presented as discontinued operations because separate financial information is not available for this business for the periods prior to the first quarter of 2006. The wholesale marketing business does not meet the criteria to be held for sale. In November of 2005, NU Enterprises sold SECI-NH and Woods Network. In April of 2006, NU Enterprises sold a portion of Woods Electrical. On May 5, 2006, NU Enterprises completed the sale of SESI. On June 1, 2006, NU Enterprises completed the sale of Select Energy's retail marketing business. On November 1, 2006, NU completed the sale of NGC and Mt. Tom.

For further information regarding these companies, see Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements. Management will continue to evaluate this classification for NU Enterprises' businesses that are being exited.

Impairment of Long-Lived Assets: The company evaluates long-lived assets such as property, plant and equipment to determine if these assets are impaired when events or changes in circumstances occur such as the 2005 announced decisions to exit the NU Enterprises businesses.

When the company believes one of these events has occurred, the determination needs to be made whether a long-lived asset should be classified as held and used or held for sale. For assets classified as held and used, the company estimates the undiscounted future cash flows associated with the long-lived asset or asset group and an impairment loss is recognized if the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. For assets held for sale, a long-lived asset or disposal group is measured at the lower of its carrying amount or fair value less cost to sell and depreciation of these assets is discontinued.

In order to estimate an asset's future cash flows, the company considers historical cash flows, changes in the market and other factors that may affect future cash flows. The company considers various relevant factors, including the method and timing of recovery, forward price curves for energy, fuel costs and operating costs. Actual future market prices, costs and cash flows could vary significantly from those assumed in the estimates and the impact of such variations could be material.

In the first quarter of 2006, management determined that the competitive generation business, which includes NGC and Mt. Tom, should be classified as assets held for sale rather than held and used and that no impairment existed for the competitive generation assets as the fair value of those assets less their expected costs to sell exceeded their carrying values. At September 30, 2006, management determined that the best estimate for the fair value of the competitive generation assets was the purchase price agreed to by ECP. This purchase price was above the carrying value of the competitive generation assets and therefore indicated that no impairment of the competitive generation assets existed at September 30, 2006.

For further information regarding impairment charges and assets held for sale, see Note 3, "Restructuring and Impairment Charges," and Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements.

Other Matters

Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 7, "Commitments and Contingencies," to the condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments: For updated information regarding NU's contractual obligations and commercial commitments at September 30, 2006, see Note 7C, "Commitments and Contingencies -

Long-Term Contractual Arrangements," to the condensed consolidated financial statements.

Consolidated Edison, Inc. Merger Litigation: Certain gain and loss contingencies exist with regard to the merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation.

On March 5, 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the parties' 1999 merger agreement (Merger Agreement). On March 12, 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In an opinion dated October 12, 2005, a panel of three judges at the Second Circuit held that the shareholders of NU had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. NU's request for a rehearing was denied on January 3, 2006. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of "at least $314 million." NU opted not to seek review of this ruling by the United States Supreme Court. On April 7, 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. NU's motion asserts that NU is entitled to judgment in its favor with respect to this claim based on the undisputed material facts and applicable law. The matter is fully briefed and awaiting a decision. At this stage, NU cannot predict the outcome of this matter or its ultimate effect on NU.

Accounting Standards Issued But Not Yet Adopted:

A.

Accounting for Servicing of Financial Assets: In March of 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 156, "Accounting for Servicing of Financial Assets - An Amendment of FASB Statement No. 140." SFAS No. 156 requires an entity to recognize a servicing asset or liability at fair value each time it undertakes an obligation to service a financial asset by entering into a servicing contract in a transfer of the servicer's financial assets that meets the requirements for sale accounting and in other circumstances. Servicing assets and liabilities may be subsequently measured through either amortization or recognition of fair value changes in earnings. SFAS No. 156 is required to be applied prospectively to transactions beginning in the first quarter of 2007 and may affect the accounting treatment of CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. Implementation of SFAS No. 156 is not expected to have a material effect on the company's financial statements.

B.

Uncertain Tax Positions: On July 13, 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109." FIN 48 addresses the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. FIN 48 is required to be implemented prospectively in the first quarter of 2007 as a change in accounting principle with a cumulative effect adjustment reflected in the January 1, 2007 balance of retained earnings. The company is currently evaluating the potential impacts of FIN 48 on its financial statements.

C.

Fair Value Measurements: On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is expected to be applied to fair value measurements of derivative contracts that are subject to mark-to-market accounting and other assets and liabilities reported at fair value. In most cases, SFAS No. 157 is required to be implemented prospectively with adjustments to fair value reflected as a cumulative effect adjustment to the opening balance of retained earnings as of January 1, 2008. The company is evaluating the potential impacts of SFAS No. 157 on its financial statements.

D.

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans: On September 29, 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." Effective prospectively beginning on December 31, 2006, SFAS No. 158 requires balance sheet recognition of the funded status of pension and postretirement benefit plans, with the difference between the funded status and the accrued or prepaid position recognized as a charge or credit to shareholders' equity through other comprehensive income. The company is currently evaluating the potential balance sheet impacts of implementing SFAS No. 158 and whether NU's regulated companies will report regulatory assets or liabilities rather than charges or credits to shareholders' equity in recognition of the recovery of pension and postretirement expenses in rates. Implementing SFAS No. 158 could have a material negative effect on NU's and its subsidiaries shareholders' equity balances, the amount of which would depend upon the plans' funded status at December 31, 2006 and whether regulatory accounting is determined to apply to NU's regulated companies upon adoption of the standard. At December 31, 2005, the total difference between the funded status and the accrued or prepaid positions for NU's pension and postretirement plans was over $700 million on a pre-tax basis.

Forward Looking Statements: This discussion and analysis includes statements concerning NU's expectations, plans, objectives, future financial performance 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. In some cases the reader can identify these forward looking statements by words such as "estimate," "expect," "anticipate," "intend," "plan," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are 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, expiration or initiation of significant energy supply contracts, changes in levels of capital expenditures, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, effectiveness of risk management policies and procedures, changes in accounting standards and financial reporting regulations, fluctuations in the value of electricity positions, the methods, timing and results of disposition of competitive businesses, actions of rating agencies, terrorist attacks on domestic energy facilities and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the Securities and Exchange Commission (SEC). Management undertakes no obligation to update the information contained in any forward looking statements to reflect developments or circumstances occurring after the statement is made.

Web Site: Additional financial information is available through NU's 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/(loss) for NU included in this report on Form 10-Q for the three and nine months ended September 30, 2006:

	Income Statement Variances (Millions of Dollars) 2006 over/(under) 2005			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues:	$ (161)	(9) %	$ (117)	(2) %
Operating Expenses:				
Fuel, purchased and net interchange power	(121)	(10)	(136)	(4)
Other operation	(20)	(8)	38	5
Wholesale contract market changes, net	(106)	(a)	(345)	(96)
Restructuring and impairment charges	(4)	(73)	(19)	(66)
Maintenance	6	11	7	5
Depreciation	5	9	13	8
Amortization	(89)	(a)	(78)	(62)
Amortization of rate reduction bonds	3	7	9	7
Taxes other than income taxes	2	3	5	3
Total operating expenses	(324)	(18)	(506)	(9)
Operating Income/(Loss)	163	(a)	389	(a)
Interest expense, net	4	6	9	5
Other income, net	2	18	14	50
Income/(Loss) before income tax benefit	161	(a)	394	(a)
Income tax benefit	(41)	(a)	46	35
Preferred dividends of subsidiary	-	-	-	-
Income/(loss) from continuing operations	202	(a)	348	(a)
Income from discontinued operations	4	68	16	(a)

Net Income/(Loss)	$	206	(a) %	$	364	(a) %

(a) Percent greater than 100.

Comparison of the Third Quarter of 2006 to the Third Quarter of 2005

Operating Revenues

Operating revenues decreased $161 million primarily due to lower revenues from NU Enterprises ($257 million), partially offset by higher distribution revenues ($79 million) and higher regulated transmission business revenues ($15 million).

NU Enterprises' revenues decreased $257 million primarily due to the divesture of the competitive businesses which include primarily the sale of the retail marketing business on June 1, 2006 ($233 million), the sale of the Massachusetts service location of SECI-CT in January of 2006 and lower revenues from certain other competitive businesses not classified as discontinued operations ($24 million).

Distribution revenues increased $79 million primarily due to higher electric distribution revenues ($76 million) and higher gas distribution revenues ($3 million). Higher electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($70 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution revenue tracking components increase of $70 million is primarily due to the pass through of higher energy supply costs ($134 million), partially offset by lower PSNH SCRC ($42 million), lower wholesale revenues ($18 million) and lower CL&P FMCC charges ($4 million).

The distribution component of these companies and the retail transmission component of PSNH which flow through to earnings increased $6 million primarily due to an increase in regulated retail rates, partially offset by a decrease in retail sales. The distribution retail electric sales were negatively affected by weather impacts in 2006 as compared with 2005 and by price elasticity driven by higher energy prices in 2006. Retail kWh electric sales decreased by 4.5 percent in 2006 compared with 2005 (a 1.8 percent decrease on a weather-normalized basis). Absent the impacts of weather, management believes the decline in sales is primarily due to higher prices driven by the higher fuel and purchased power costs.

Transmission business revenues increased $15 million primarily due to a higher transmission investment base and the recovery of higher operating expenses in 2006 as allowed under FERC Tariff Schedule 21.

Gas distribution revenues increased $3 million primarily due to higher sales volumes. Firm gas sales increased 1.9 percent in 2006 compared to 2005. On a weather adjusted basis, firm gas sales increased 0.5 percent.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $121 million primarily due to lower costs at NU Enterprises ($277 million), partially offset by higher purchased power costs for distribution ($156 million).

NU Enterprises' lower costs of $277 million are primarily due to the sale of the retail marketing business on June 1, 2006.

The $156 million increase in distribution purchased power costs is primarily due to higher standard offer supply costs for CL&P and WMECO ($139 million), higher expenses for PSNH primarily due to higher energy costs ($14 million) and higher Yankee Gas expenses as a result of higher gas sales ($3 million).

Other Operation

Other operation expenses decreased $20 million primarily due to lower NU Enterprises' expenses of $29 million, partially offset by higher distribution and transmission expenses ($9 million).

NU Enterprises' expenses decreased $29 million primarily due to the divesture of the competitive businesses which include the sale of the retail marketing business on June 1, 2006 and exiting all of the New England wholesale marketing business in 2005 ($17 million), the sale of the Massachusetts service location of SECI-CT in January of 2006 and lower expenses from certain other competitive businesses not classified as discontinued operations ($12 million).

Higher distribution and transmission expenses of $9 million are primarily due to higher distribution and transmission administrative and general expenses ($3 million) primarily due to higher employee related costs, higher CL&P

conservation and load management (C&LM) expenses ($2 million) and higher distribution uncollectible expenses ($1 million).

Wholesale Contract Market Changes, Net

See Note 2, "Wholesale Contract Market Changes," to the condensed consolidated financial statements for a description and explanation of this amount.

Restructuring and Impairment Charges

See Note 3, "Restructuring and Impairment Charges," to the condensed consolidated financial statements for a description and explanation of this amount.

Maintenance

Maintenance expenses increased $6 million primarily due to higher CL&P storm-related maintenance costs ($3 million) and higher PSNH generation costs as a result of a planned overhaul of a generating plant in 2006 ($3 million).

Depreciation

Depreciation increased $5 million primarily due to higher distribution and transmission plant balances due to the ongoing construction program.

Amortization

Amortization decreased $89 million primarily due to PSNH distribution ($62 million) and CL&P distribution ($24 million). The PSNH decrease is primarily due to completing the recovery of its non-securitized stranded costs as of June 30, 2006. The CL&P decrease is primarily due to lower amortization related to distribution's recovery of transition charges ($23 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $3 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 $2 million primarily due to higher distribution and transmission property taxes ($2 million) and higher Connecticut gross earnings tax primarily due to higher CL&P distribution revenues ($2 million), partially offset by lower NU Enterprises' other taxes primarily due to the sale of the retail marketing business on June 1, 2006 ($2 million).

Interest Expense, Net

Interest expense, net increased $4 million primarily due to the issuance of long-term debt of $250 million for CL&P which was issued in June of 2006.

Other Income, Net

Other income, net increased $2 million primarily due to higher investment income ($2 million) and higher CL&P Energy Independence Act (EIA) incentives ($1 million).

Income Tax Benefit

Income tax benefit increased $41 million primarily due to favorable tax adjustments ($83 million), partially offset by higher pre-tax earnings ($42 million). A tax benefit of $74 million was recorded to remove deferred tax balances associated with a ruling received from the IRS and accepted by the DPUC in the third quarter. Additional tax benefits resulted from the reversal of a state tax valuation allowance ($8 million), and year over year change in estimate to actual adjustments ($5 million).

Income from Discontinued Operations

For the three months ended September 30, 2006 and 2005, the operations of NGC and Mt. Tom were presented as discontinued operations as a result of meeting certain criteria requiring this presentation. In addition, SESI, a portion of Woods Electrical, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the three months ended September 30, 2005. SESI was sold in May of 2006, a portion of Woods Electrical was sold in April of 2006, and SECI-NH (including Reeds Ferry) and Woods Network were sold in November of 2005. Under this presentation, revenues and expenses of these businesses are included in the income from discontinued operations on the condensed consolidated statements of income/(loss). See Note 4, "Assets Held for Sale and Discontinued Operations," to the condensed consolidated financial statements for a description and explanation of the discontinued operations.

<u>Comparison of the First Nine Months of 2006 to the First Nine Months of 2005</u>

Operating Revenues

Operating revenues decreased $117 million primarily due to lower revenues from NU Enterprises ($626 million), partially offset by higher distribution revenues ($472 million) and higher regulated transmission business revenues ($30 million).

NU Enterprises' revenues decreased $626 million primarily due to the divesture of the competitive businesses which include exiting all of its New England wholesale sales obligations in 2005 by either buying out those contracts or assigning its obligations to third parties and the sale of the retail marketing business on June 1, 2006 ($571 million), the sale of the Massachusetts service location of SECI-CT in January of 2006 and lower revenues from certain other competitive businesses not classified as discontinued operations ($55 million).

Distribution revenues increased $472 million primarily due to higher electric distribution revenues ($480 million), partially offset by lower gas distribution revenues ($8 million). Higher electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($466 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution revenue tracking components increase of $466 million is primarily due to the pass through of higher energy supply costs ($472 million) and higher CL&P FMCC charges ($48 million), partially offset by lower PSNH SCRC ($49 million) and lower wholesale revenues ($12 million).

The distribution component of these companies and the retail transmission component of PSNH which flow through to earnings increased $15 million primarily due to an increase in regulated retail rates, partially offset by a decrease in retail sales. The distribution retail electric sales were negatively affected by weather impacts in 2006 as compared with 2005 and by price elasticity driven by higher energy prices in 2006. Retail kWh electric sales decreased by 3.6 percent in 2006 compared with 2005 (a 1.1 percent decrease on a weather-normalized basis). Absent the impacts of weather, management believes the decline in sales is primarily due to higher prices driven by the higher fuel and purchased power costs.

Transmission business revenues increased $30 million primarily due to a higher transmission investment base and the recovery of higher operating expenses in 2006 as allowed under FERC Tariff Schedule 21.

The increase in electric distribution revenues is partially offset by lower gas distribution revenues of $8 million primarily due to lower sales volumes. Firm gas sales decreased 9.3 percent in 2006 compared with 2005 primarily due to a mild winter and increased conservation driven by higher gas costs. On a weather adjusted basis, firm gas sales decreased 3.2 percent.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $136 million primarily due to lower costs at NU Enterprises ($636 million), partially offset by higher purchased power costs for distribution ($499 million).

NU Enterprises' lower costs of $636 million are primarily due to the divesture of the competitive businesses. Wholesale marketing costs decreased $441 million primarily due to the absence of servicing the New England wholesale sales contracts that were exited in 2005. The remaining wholesale obligations in the PJM power pool expire in 2008 and the remaining wholesale obligation in New York continues through 2013. This decrease is also due to the sale of the retail marketing business on June 1, 2006 ($195 million).

The $499 million increase in distribution purchased power costs is primarily due to higher standard offer supply costs for CL&P and WMECO ($447 million) and higher expenses for PSNH primarily due to higher energy costs ($56 million). The increase in distribution purchased power costs is partially offset by lower Yankee Gas expenses as a result of lower gas sales ($4 million).

Other Operation

Other operation expenses increased $38 million primarily due to higher distribution and transmission expenses ($60 million), partially offset by lower NU Enterprises' expenses ($22 million).

Higher distribution and transmission expenses of $60 million are primarily due to higher distribution reliability must run (RMR) costs and other power pool related expenses ($38 million), higher distribution and transmission administrative and general expenses ($16 million) primarily due to higher employee related costs, higher CL&P C&LM expenses ($5 million) and higher distribution uncollectible expenses ($3 million).

NU Enterprises' expenses decreased $22 million primarily due to a $76 million decrease in NU Enterprises' expenses primarily due to the divesture of the competitive businesses which include the sale of the Massachusetts service location of SECI-CT in January of 2006 and lower expenses from certain other competitive businesses not classified as discontinued operations ($44 million), the sale of the retail marketing business on June 1, 2006 and exiting all of the New England wholesale marketing business in 2005 ($32 million). Partially offsetting the decrease is a charge to record the retail marketing business at its fair value less cost to sell ($54 million).

Wholesale Contract Market Changes, Net

See Note 2, "Wholesale Contract Market Changes," to the condensed consolidated financial statements for a description and explanation of this amount.

Restructuring and Impairment Charges

See Note 3, "Restructuring and Impairment Charges," to the condensed consolidated financial statements for a description and explanation of this amount.

Maintenance

Maintenance expenses increased $7 million primarily due to higher CL&P storm-related maintenance costs ($4 million) and higher PSNH generation costs as a result of a planned overhaul of a generating plant in 2006 ($4 million).

Depreciation

Depreciation increased $13 million primarily due to higher distribution and transmission plant balances due to the ongoing construction program.

Amortization

Amortization decreased $78 million primarily due to PSNH distribution ($39 million) and CL&P distribution ($34 million). The PSNH decrease is primarily due to completing the recovery of its non-securitized stranded costs as of June 30, 2006. The CL&P decrease is primarily due to lower amortization related to distribution's recovery of transition charges ($32 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $9 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 distribution and transmission property taxes ($5 million) and higher Connecticut gross earnings tax primarily due to higher CL&P distribution revenues ($3 million), partially offset by lower NU Enterprises' other taxes primarily due to the sale of the retail marketing business on June 1, 2006 ($2 million).

Interest Expense, Net

Interest expense, net increased $9 million primarily due to the issuance of long-term debt of $350 million in 2005 and $250 million in 2006. The 2005 long-term debt issuance includes $200 million for CL&P in April and the issuance of $50 million per company related to Yankee Gas, WMECO and PSNH in July, August and October, respectively. The 2006 long-term debt issuance was $250 million for CL&P which was issued in June of 2006. The increase is partially offset by the absence of the interest related to the final decision on the streetlight refund docket recorded in the second quarter of 2005 ($4 million).

Other Income, Net

Other income, net increased $14 million primarily due to higher investment income ($9 million), which includes $2 million for CL&P related to a Connecticut tax refund claim settlement, higher CL&P EIA incentives ($4 million) and a $3 million gain associated with the sale of 2.7 million shares of Globix. The increase is also due to higher AFUDC ($3 million), partially offset by the CYAPC regulatory asset write-off ($3 million).

Income Tax Benefit

Income tax benefit decreased $46 million due to higher pre-tax earnings ($137 million), partially offset by favorable tax adjustments ($91 million). A tax benefit of $74 million was recorded to remove deferred tax balances associated with a ruling received from the IRS and accepted by the DPUC in the third quarter. Additional tax benefits resulted from the reversal of a state tax valuation allowance ($8 million), year over year change in estimate to actual adjustments ($5 million) and higher state tax credits ($4 million).

Income from Discontinued Operations

For the nine months ended September 30, 2006 and 2005, the operations of NGC, Mt. Tom, SESI and a portion of Woods Electrical were presented as discontinued operations as a result of meeting certain criteria requiring this presentation. SESI was sold in May of 2006 and a portion of Woods Electrical was sold in April of 2006. In addition, SECI-NH (including Reeds Ferry) and Woods Network are included in discontinued operations for the nine months ended September 30, 2005. These businesses were sold in November of 2005. Under this presentation, revenues and expenses of these businesses are included in the income from discontinued operations on the condensed consolidated statements of income/(loss). See Note 4, "Assets Held for Sale and 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 2006 reports on Form 10-Q and the NU 2005 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 third quarter and the nine months ended September 30, 2006:

Income Statement Variances

(Millions of Dollars)

2006 over/(under) 2005

	Third Quarter	Percent	Nine Months	Percent
Operating Revenues:	$ 131	14 %	$ 439	17 %
Operating Expenses:				
Fuel, purchased and net interchange power	136	23	380	24
Other operation	12	8	66	16
Maintenance	3	10	4	6
Depreciation	5	13	11	11
	(25)	(a)	(34)	(a)

Amortization of regulatory (liabilities)/assets, net						
Amortization of rate reduction bonds		2	7		6	7
Taxes other than income taxes		2	6		4	4
Total operating expenses		135	15		437	18
Operating (Loss)/Income		(4)	(7)		2	1
Interest expense, net		2	8		2	2
Other income, net		-	-		5	25
(Loss)/income before income tax expense		(6)	(15)		5	5
Income tax benefit		(80)	(a)		(81)	(a)
Net Income	$	74	(a) %	$	86	(a) %

(a) Percent greater than 100.

<u>Comparison of the Third Quarter of 2006 to the Third Quarter of 2005</u>

Operating Revenues

Operating revenues increased $131 million due to higher distribution business revenues ($117 million) and higher transmission business revenues ($14 million).

The distribution business revenue increase of $117 million is due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution revenue tracking components increased primarily due to higher TSO related revenues ($128 million), which are partially offset by lower wholesale revenues ($11 million). The distribution component of revenues which impact earnings were flat, with an increase in rates offset by lower sales. Retail sales for the third quarter were 5.2 percent below the third quarter of 2005.

Transmission business revenues increased $14 million primarily due to a higher rate base and higher operating expenses which are recovered under the NU Schedule 21 tariff.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $136 million primarily due to higher standard offer supply costs and higher purchased power costs as a result of higher energy prices, which are included in regulatory commission approved tracking mechanisms.

Other Operation

Other operation expenses increased $12 million primarily due to higher administrative and general costs ($4 million) which include pension, other benefit costs, and incentive accruals, higher C&LM expenses ($3 million) which are included in a regulatory rate tracking mechanism, higher distribution storm expenses ($2 million), and higher customer account expenses ($3 million).

Maintenance

Maintenance expenses increased $3 million primarily due to higher expenses related to overhead lines maintenance ($1 million), line transformer maintenance ($1 million), and station equipment maintenance ($1 million).

Depreciation

Depreciation expense increased $5 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $25 million primarily due to the lower recovery of transition charges ($23 million).

Amortization of Rate Reduction Bonds

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

Taxes Other Than Income Taxes

Taxes other than income taxes increased $2 million primarily due to higher property taxes ($1 million) and higher gross earnings tax ($1 million).

Interest Expense, Net

Interest expense, net increased $2 million primarily due to higher interest on long-term debt as a result of new debt issued in June of 2006 ($4 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($2 million).

Income Tax Benefit

Income tax expense decreased $80 million in the third quarter of 2006 due to lower pre-tax earnings and favorable tax adjustments. A tax benefit of $74 million was recorded to remove deferred tax balances associated with the PLR received from the IRS and accepted by the DPUC in the third quarter. Additional tax benefits resulted from lower plant related flow through adjustments, year over year change in estimate to actual adjustments and higher state tax credits.

Comparison of the First Nine Months of 2006 to the First Nine Months of 2005

Operating Revenues

Operating revenues increased $439 million due to higher distribution business revenues ($413 million) and higher transmission business revenues ($26 million).

The distribution business revenue increase of $413 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($408 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution component of rates which impact earnings increased $5 million, primarily due to higher retail rates as a result of the rate increase effective January 1, 2006 and the absence in 2006 of an additional reserve recorded in 2005 to reflect the final decision on the streetlight docket ($2 million), partially offset by decreased sales volumes. Retail sales for the first nine months of 2006 were 4.3 percent lower than the same period in 2005.

The distribution business revenue tracking components increased $408 million primarily due to higher TSO related revenues ($354 million), an increase in revenues associated with the recovery of FMCC charges ($48 million), and higher retail transmission revenues ($16 million), partially offset by lower wholesale revenues ($11 million).

Transmission business revenues increased $26 million primarily due to a higher rate base and higher operating expenses which are recovered under the NU Schedule 21 tariff.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $380 million primarily due to higher standard offer supply costs and higher purchased power costs as a result of higher energy prices, which are included in regulatory commission approved tracking mechanisms.

Other Operation

Other operation expenses increased $66 million primarily due to higher RMR costs ($37 million) which are tracked and recovered through the FMCC, higher administrative and general costs ($12 million) which include pension, other benefit costs, annual incentive accruals, and regulatory commission expenses, higher C&LM expenses ($6 million) which are included in a regulatory rate tracking mechanism, and higher uncollectible account expenses ($4 million).

Maintenance

Maintenance expenses increased $4 million primarily due to higher tree trimming expenses ($2 million), higher expenses related to underground lines maintenance ($2 million) and higher station equipment maintenance expenses ($1 million).

Depreciation

Depreciation expense increased $11 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $34 million primarily due to lower amortization related to the recovery of transition charges ($32 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $6 million. The higher portion of principal within the rate reduction bond's payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4 million primarily due to higher gross earnings taxes ($3 million) and higher property taxes ($1 million).

Interest Expense, Net

Interest expense, net increased $2 million primarily due to higher interest on long-term debt ($8 million) mainly as a result of new debt issued in June of 2006, higher interest on Millstone prior spent nuclear fuel disposal costs ($3 million), and higher short-term debt interest expense ($2 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($7 million) and the absence of interest expense related to the final decision on the streetlight refund docket recorded in the second quarter of 2005 ($4 million).

Other Income, Net

Other income, net increased $5 million primarily due to higher EIA incentives ($4 million).

Income Tax Benefit

Income tax expense decreased $81 million in the first nine months of 2006 due to favorable tax adjustments, partially offset by higher pre-tax earnings. A tax benefit of $74 million was recorded to remove deferred tax balances associated with the PLR received from the IRS and accepted by the DPUC in the third quarter. Additional tax benefits resulted from higher state tax credits, a favorable Connecticut tax settlement, year over year change in estimate to actual adjustments and higher tax exempt Medicare subsidy.

LIQUIDITY

Net cash flows from operations decreased by $10.3 million from $159.2 million for the first nine months of 2005 to $148.9 million for the first nine months of 2006. The decrease in operating cash flows is due primarily to higher regulatory refunds as CL&P refunded previous overrecoveries to its ratepayers to moderate the increase in CL&P's TSO rates that became effective on January 1, 2006 and an estimated federal income tax payment of approximately $20 million related to CL&P's 2005 tax return. This payment was made in the first quarter of 2006. No such federal income tax payment was made in the first quarter of 2005. The decrease in operating cash flows is offset by changes in investments in securitizable assets which increased more in the first nine months of 2005 than in the first nine months of 2006. Investments in securitizable assets are affected by the level of accounts receivable and by the amount of accounts receivable sold through CRC to a financial institution. In the first nine months of 2006, the level of accounts receivable increased as compared to 2005, partially offset by the increase in the cash receipts from the sale of receivables to the financial

institution totaling approximately $10 million in 2006 as compared to 2005. The company expects net cash flows to increase and CL&P refunds to decline in the fourth quarter of 2006 as a result of a DPUC decision to terminate a $0.009 per kWh credit on customer bills to refund previous CTA overrecoveries.

Cash capital expenditures in this liquidity section do not include cost of removal, AFUDC, and the capitalized portion of pension expense or income. CL&P's capital expenditures totaled $388.4 million for the first nine months of 2006 compared to $309 million in the first nine months of 2005. This increase is primarily due to higher transmission capital expenditures.

Financing activities increased for the first nine months of 2006 primarily as a result of CL&P's $250 million debt issuance. On June 7, 2006, CL&P closed on the sale of $250 million, 30-year first mortgage bonds with a coupon rate of 6.35 percent. In addition, at September 30, 2006, CL&P's financing activities also included $60 million of capital contributions from NU, offset by dividend payments to NU of $47.8 million.

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 2006 reports on Form 10-Q and the NU 2005 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 third quarter and the nine months ended September 30, 2006:

	Income Statement Variances (Millions of Dollars) 2006 over/(under) 2005			
	Third Quarter	**Percent**	**Nine Months**	**Percent**
Operating Revenues:	$ (40)	(13) %	$ 41	5 %
Operating Expenses:				
Fuel, purchased and net interchange power	14	11	56	15
Other operation	(1)	(3)	(2)	(2)
Maintenance	4	29	4	10
Depreciation	1	7	2	7
	(62)	(a)	(39)	(39)

Amortization of regulatory (liabilities)/assets, net					
Amortization of rate reduction bonds		1	6		2	6
Taxes other than income taxes		-	-		1	3
Total operating expenses		(43)	(15)		24	3
Operating (Loss)/Income		3	11		17	23
Interest expense, net		-	-		-	-
Other income, net		1	(a)		2	(a)
(Loss)/income before income tax expense		4	26		19	47
Income tax expense		8	(a)		21	(a)
Net (Loss)/Income	$	(4)	(34) %	$	(2)	(6) %

(a) Percent greater than 100.

Comparison of the Third Quarter of 2006 to the Third Quarter of 2005

Operating Revenues

Operating revenues decreased $40 million primarily due to lower distribution business revenue ($41 million), partially offset by higher transmission business revenue ($1 million). The distribution business revenue decrease of $41 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($47 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution and transmission components of PSNH's retail rates which impact earnings increased $6 million primarily due to the distribution rate increase effective July 1, 2006, partially offset by lower retail sales. Retail sales decreased 2.1 percent in 2006 compared to the same period of 2005.

The distribution revenue tracking components decreased $47 million primarily due to a decrease in the SCRC ($42 million) mainly as a result of the rate decrease effective July 1, 2006 and a decrease in wholesale revenues ($6 million), partially offset by an increase in the ES rate component of retail revenues ($3 million), also effective July 1, 2006.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power increased $14 million primarily due to the higher cost of energy as a result of higher fuel prices, which are included in regulatory commission approved tracking mechanisms.

Other Operation

Other operation expenses decreased $1 million primarily due to lower load dispatch expenses ($2 million) and lower overhead line expenses ($1 million), partially offset by higher customer service expenses ($1 million).

Maintenance

Maintenance expenses increased $4 million primarily due to higher generation costs as a result of the planned overhaul of a generating plant in 2006 ($3 million) and higher tree trimming expenses ($1 million).

Depreciation

Depreciation expense increased $1 million primarily due to higher plant balances resulting from the ongoing construction program.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $62 million as a result of PSNH completing the recovery of its non-securitized stranded costs in June of 2006.

Amortization of Rate Reduction Bonds

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

Other Income, Net

Other income, net increased $1 million primarily due to a higher AFUDC as a result of increased eligible CWIP for generation, lower short-term debt, and a greater component of CWIP being subject to a higher equity rate.

Income Tax Expense

Income tax expense increased $8 million due to higher pre-tax earnings and an increase in the effective tax rate from 15.9 percent to 55.9 percent. The increase in the effective tax rate primarily results from higher state income tax expense and the regulatory recovery of tax expense associated with nondeductible acquisition costs. The increase in state income taxes results from higher unitary taxable income due primarily to the sale of competitive generation assets.

Comparison of the First Nine Months of 2006 to the First Nine Months of 2005

Operating Revenues

Operating revenues increased $41 million primarily due to higher distribution revenue ($37 million) and higher transmission revenue ($4 million). The distribution revenue increase of $37 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($27 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution and transmission components of PSNH's retail rates which impact earnings increased $10 million primarily due to the distribution rate increase effective July 1, 2006, partially offset by lower retail sales. Retail sales decreased 1.2 percent in 2006 compared to the same period of 2005.

The distribution revenue tracking components increased $27 million primarily due to an increase in the ES rate component of retail revenues of $83 million, mainly due to an increase in the cost of fuel and purchased power, partially offset by a decrease in the SCRC ($49 million) mainly as a result of the rate decrease effective July 1, 2006.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power increased $56 million primarily due to the higher cost of energy as a result of higher fuel prices, which are included in regulatory commission approved tracking mechanisms.

Other Operation

Other operation expenses decreased $2 million primarily due to lower load dispatch expenses ($3 million) and lower customer service expenses ($2 million), partially offset by higher administrative expenses ($4 million) primarily due to higher pension and medical costs ($2 million).

Maintenance

Maintenance expenses increased $4 million primarily due to higher generation costs as a result of the planned overhaul of a generating plant in 2006 ($3 million) and higher overhead line maintenance expenses ($2 million).

Depreciation

Depreciation expense increased $2 million primarily due to higher plant balances resulting from the ongoing construction program.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $39 million primarily due to the third quarter variance ($62 million), which is a result of completing the recovery of non-securitized stranded costs in June of 2006, partially offset by the higher amortization expense which occurred in the first six months ($22 million) primarily due to over-recovery of ES costs in February and March of 2006 ($23 million).

Amortization of Rate Reduction Bonds

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

Taxes Other Than Income Taxes

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

Other Income, Net

Other income, net increased $2 million primarily due to a higher AFUDC as a result of increased eligible CWIP for generation, lower short-term debt, and a greater component of CWIP being subject to a higher equity rate.

Income Tax Expense

Income tax expense increased $21 million due to higher pre-tax earnings and an increase in the effective tax rate from 25.8 percent to 52.6 percent. The increase in the effective tax rate primarily results from higher state income tax expense and the regulatory recovery of tax expense associated with nondeductible acquisition costs. The increase in state income taxes results from higher unitary taxable income due primarily to the sale of competitive generation assets.

LIQUIDITY

Net cash flows from operations decreased by $23.2 million from $184 million for the first nine months of 2005 to $160.8 million for the first nine months of 2006. The decrease in operating cash flows is primarily due to the acceleration of estimated income tax payments in 2006. Offsetting this decrease is an increase in accounts receivable collections. PSNH's operating cash flows are expected to decline in the fourth quarter of 2006 and thereafter as a result of a significant reduction in approved SCRC rates to an average rate of $0.0155 per kWh from the current average rate of $0.0335 per kWh effective on July 1, 2006. That decline, which amounts to approximately $170 million annually, is the result of the completion of PSNH's recovery of its Part 3 non-securitized stranded costs as of June 30, 2006.

Cash capital expenditures in this liquidity section do not include cost of removal, AFUDC, and the capitalized portion of pension expense or income. PSNH's capital expenditures totaled $81.9 million for the first nine months of 2006 compared to $124.5 million in the first nine months of 2005. This reduction is primarily the result of less Northern Wood Power Project capital additions in 2006.

Financing activities for the first nine months of 2006 included the payment of $35.5 million in dividends to NU, compared to $18.4 million for the first nine months of 2005.

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 2006 reports on Form 10-Q and the NU 2005 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 third quarter and the nine months ended September 30, 2006:

Income Statement Variances

(Millions of Dollars)

2006 over/(under) 2005

	Third Quarter	Percent	Nine Months	Percent
Operating Revenues:	$ -	- %	$ 31	10 %
Operating Expenses:				
Fuel, purchased and net interchange power	4	6	37	20
Other operation	(1)	(8)	(3)	(5)
Maintenance	1	18	-	-
Depreciation	-	-	1	6
	(2)	(a)	(4)	(a)

Amortization of regulatory (liabilities)/assets, net						
Amortization of rate reduction bonds		-	-		-	-
Taxes other than income taxes		-	-		-	-
Total operating expenses		2	2		31	12
Operating (Loss)/Income		(2)	(13)		-	-
Interest expense, net		-	-		1	4
Other income, net		-	-		-	-
(Loss)/income before income tax expense		(2)	(22)		(1)	(4)
Income tax (benefit)/expense		(1)	(20)		-	-
Net (Loss)/Income	$	(1)	(24) %	$	(1)	(4) %

(a) Percent greater than 100.

<u>Comparison of the Third Quarter of 2006 to the Third Quarter of 2005</u>

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $4 million primarily due to higher default service supply costs, which are included in a regulatory commission approved tracking mechanism.

Other Operation

Other operation expenses decreased $1 million primarily due to lower retail transmission expenses.

Maintenance

Maintenance expenses increased $1 million primarily due to higher expenses related to overhead lines maintenance and higher tree trimming expenses.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $2 million primarily due to the deferral of transition costs, as a result of lower transition revenues and higher transition costs.

Income Tax Expense

Income tax expense decreased $1 million in the third quarter of 2006 due to lower pre-tax earnings, partially offset by a higher effective tax rate. The effective tax rate increased from 42.7 percent to 44.1 percent primarily due to a 2006 state tax loss that provides no benefit.

Comparison of the First Nine Months of 2006 to the First Nine Months of 2005

Operating Revenues

Operating revenues increased $31 million compared to the same period in 2005, primarily due to higher distribution business revenue ($31 million). The distribution business revenue increase of $31 million is primarily due to the components of revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($31 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods. The distribution revenue tracking components increase of $31 million is primarily due to the pass through of higher energy supply costs ($36 million), partially offset by lower retail transmission revenues ($4 million).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $37 million primarily due to higher default service supply costs, which are included in a regulatory commission approved tracking mechanism.

Other Operation

Other operation expenses decreased $3 million primarily due to lower retail transmission expenses.

Depreciation

Depreciation expense increased $1 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory (Liabilities)/Assets, Net

Amortization of regulatory (liabilities)/assets, net decreased $4 million primarily due to the deferral of transition costs, as a result of lower transition revenues and higher transition costs.

Interest Expense, Net

Interest expense, net increased $1 million primarily due to higher long-term debt levels as a result of the issuance of $50 million of ten-year senior notes in August of 2005 ($2 million), partially offset by lower rate reduction bond interest resulting from lower principal balances outstanding ($1 million).

LIQUIDITY

Net cash flows from operations decreased by $15.3 million from $18.7 million for the first nine months of 2005 to $3.4 million for the first nine months of 2006. The decrease in operating cash flows is primarily due to an increase in the regulatory assets relating to a significant increase in the retail transmission costs driven by RMR costs that have been deferred and will be recovered from customers at a future date. Additionally, there was a decrease in the transition charge to customers due to a significant 2004 overrecovery under the transition charge. The implementation of the distribution rate settlement agreement is expected to improve WMECO's cash flows from operations in 2007 which are expected to be consistent with WMECO's 2005 cash flow from operations.

Cash capital expenditures in this liquidity section do not include cost of removal, AFUDC, and the capitalized portion of pension expense or income. WMECO's capital expenditures totaled $32.3 million for the first nine months of 2006 compared to $30.8 million for the first nine months of 2005.

At September 30, 2006, WMECO's financing activities included $28 million of capital contributions from NU, borrowings of $30 million from the Utility Group's revolving credit line, and the payment of $6 million in dividends to NU.

ITEM 3.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk Information

The merchant energy business utilizes the sensitivity analysis methodology to disclose quantitative information for its 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 management's 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. As the NU Enterprises' businesses are exited, the risks associated with commodity prices are expected to be reduced.

NU Enterprises - Wholesale Portfolio: When conducting sensitivity analyses of the change in the fair value of Select Energy's 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, 2006, Select Energy has 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 decrease in fair value of $1.5 million ($0.9 million after-tax), and a 10 percent decrease in prices for all products would have resulted in a pre-tax increase in fair value of $0.2 million ($0.1 million after-tax). A 10 percent increase in energy prices would have resulted in a $10.2 million pre-tax decrease, and a 10 percent decrease in energy prices would have resulted in a $8.9 million pre-tax increase. A 10 percent increase/(decrease) in capacity prices would have resulted in a $2.5 million pre-tax increase/(decrease). A 10 percent increase/(decrease) in ancillary prices would have resulted in a $6.2 million pre-tax increase/(decrease).

The impact of a change in electricity and natural gas prices on Select Energy's wholesale transactions at September 30, 2006 are not necessarily representative of the results that will be realized. These transactions are accounted for at fair value, and changes in market prices impact earnings.

NU Enterprises - Generation Portfolio: In conjunction with the sale of the competitive generation business on November 1, 2006, the generation portfolio was divested or otherwise closed out.

Other Risk Management Activities

Interest Rate Risk Management: NU manages its interest rate risk exposure in accordance with its written policies and procedures by maintaining a mix of fixed and variable rate debt. At September 30, 2006, approximately 89.4 percent (80.5 percent including the debt subject to the fixed-to-floating interest rate swap of variable rate debt) of NU's long-term debt, including fees and interest due for spent nuclear fuel disposal costs, is at a fixed interest rate. The remaining long-term debt is variable-rate and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in NU's variable interest rates, including the rate on debt subject to the fixed-to-floating interest rate swap, annual interest expense would have increased by $3.1 million. At September 30, 2006, NU parent maintained a fixed-to-floating interest rate swap to manage the interest rate risk associated with its $263 million of fixed-rate debt.

Credit Risk Management: Credit risk relates to the risk of loss that NU would incur as a result of non-performance by counterparties pursuant to the terms of its contractual obligations. NU serves 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 NU realizes 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 which, in turn, requires NU to manage the portfolio of market risk inherent in those transactions in a manner consistent with the parameters established by NU's risk management process.

Credit risks and market risks at NU Enterprises are monitored regularly by a Risk Oversight Council. The Risk Oversight Council is generally comprised of individuals from outside of the business lines that create or actively manage these risk exposures and functions to ensure compliance with NU's stated risk management policies.

NU tracks and re-balances the risk in its 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.

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, 2006 and December 31, 2005, Select Energy maintained collateral balances from counterparties of $0.2 million and $28.9 million, respectively. These amounts are included in counterparty deposits on the accompanying condensed consolidated balance sheets. Select Energy also has collateral balances deposited with counterparties of $34.4 million and $103.8 million at September 30, 2006 and December 31, 2005, respectively.

The Utility Group has a lower level of credit risk related to providing regulated electric and gas distribution service than NU Enterprises. However, the Utility Group companies are subject to credit risk from certain long-term or high-volume supply contracts with energy marketing companies. The Utility Group manages the credit risk with these counterparties in accordance with established credit risk practices and maintains an oversight group that monitors contracting risks, including credit risk.

In 2005, NU adopted Enterprise Risk Management (ERM) as a methodology for managing the principle risks of the company. ERM involves the application of a well-defined, enterprise-wide methodology which will enable NU's Risk and Capital Committee, comprised of senior NU officers, to oversee the identification, management and reporting of the principal capital risks of the business.

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 evaluated the design and operation of its disclosure controls and procedures at September 30, 2006 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 forms of the SEC. This evaluation was made under the supervision and with the participation of management, including NU's principal executive officer and principal financial officer, as of the end of the period covered by this report on Form 10-Q. The principal executive officer and principal financial officer concluded, based on their review, that NU's disclosure controls and procedures were effective to ensure that information required to be disclosed by NU in reports that it files under the Exchange Act i) is recorded, processed, summarized, and reported within the timeframes specified in SEC rules and forms 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.

The divestiture of NU Enterprises businesses has resulted in the appropriate elimination of certain internal controls, which we believe is a material change to the Company s internal controls over financial reporting in the third quarter of 2006. Other than the divestiture of NU Enterprises businesses, there were no changes 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" in our Annual Report on Form 10-K for the year ended December 31, 2005. With the exception of the legal proceedings described below, which description has been modified to take into account certain recent events, there have been no material changes with regard to the legal proceedings previously disclosed in our most recent Form 10-K, as such were updated by the disclosure of legal proceedings in our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2006.

CYAPC/FERC Proceeding:

On July 1, 2004, CYAPC filed with the FERC to increase its decommissioning collections from $16.7 million per year (in 2000 dollars) to $93 million per year (in 2003 dollars) for the six-year period beginning January 1, 2005. The 2003 estimate projected an increase of $395.6 million in 2003 dollars and a total cost to complete decommissioning of $831.3 million in 2003 dollars.

On August 30, 2004, the FERC issued an order accepting the CYAPC rate filing, suspending collections for five months and establishing hearing procedures.

The FERC administrative law judge conducted hearings on the reasonableness of the decommissioning rates in the spring of 2005. The DPUC argued that CYAPC's actions were imprudent and recommended a disallowance in the range of approximately $225 million to $234 million. The FERC trial staff argued that CYAPC should have used a lower gross domestic product (GDP) escalation rate in calculating the level of decommissioning charges and that the use of such rate would reduce charges by $36 million. In post trial briefs, the FERC trial staff also claimed that CYAPC's actions were imprudent and increases in decommissioning charges should be disallowed.

In an initial decision rendered on November 22, 2005, the FERC trial judge found no imprudence on CYAPC's part, and thus there was no basis for a rate disallowance. However, the trial judge agreed with the FERC trial staff's lower GDP escalator for calculating the decommissioning rate increase.

In December of 2005, the DPUC filed an appeal to the United States Court of Appeals for the D.C. Circuit, seeking review of two earlier FERC orders, in which FERC declined to address what CYAPC decommissioning costs may be charged to retail customers through retail rates by the utility companies that are wholesale purchasers under contract with CYAPC.

On August 15, 2006, CYAPC, the DPUC, the OCC, the Maine Public Utilities Commission and the Maine Public Advocate filed a settlement agreement with FERC that, if approved, disposes of the pending decommissioning litigation at FERC and at the United States Court of Appeals for the D.C. Circuit. The settlement agreement also resolves the dispute over the incentive mechanism contained in the 2000 settlement agreement between the parties, the disposition of the net proceeds from CYAPC's settlement agreement with Bechtel, CYAPC's recovery of the costs of completing decommissioning, and CYAPC's payment of dividends and return of equity capital to its shareholders.

Under the terms of the settlement agreement, the parties have agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars), taking into account actual spending through 2005 and the current estimate for completing decommissioning and long-term storage of spent fuel, a GDP escalator of 2.5 percent for costs incurred post 2006 and a 10 percent contingency factor for all decommissioning costs.

NU's electric operating subsidiaries collectively own 49 percent of CYAPC, as follows: CL&P - 34.5 percent, PSNH - 5 percent and WMECO - 9.5 percent.

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, 2005. 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. With the exception of the risk factors described below, which descriptions have been modified to take into account certain recent events, there have been no material changes with regard to the risk factors previously disclosed in our most recent Form 10-K as updated by the risk factors described in our Quarterly Reports on Form 10-Q for the periods ended March 31 and June 30, 2006.

Risks Related to the Exit from the Competitive Businesses

On March 9, 2005, NU announced the decision to exit its wholesale marketing and energy services businesses, and on November 7, 2005, NU announced the decision to exit its retail marketing and competitive generation businesses, which constituted the remainder of NU's competitive business. NU has disposed of a substantial part of its wholesale business, closed on the sale of its retail marketing business on June 1, 2006, has sold three of its six services businesses and parts of a fourth and fifth, and sold its competitive generation assets to affiliates of ECP on November 1, 2006 for $1.34 billion.

The principal remaining risks from NU's competitive businesses are related to the unhedged portion of a large wholesale contract expiring in 2013 and a portfolio of sales and purchase contracts in PJM. These wholesale contracts carry the risk that Select Energy may have to serve different-than-anticipated loads, which will vary depending on weather and other factors not in its control. Select Energy may settle these contracts in the future, possibly at costs higher than its present mark-to-market on the contracts.

In the first nine months of 2006, the wholesale marketing and competitive generation businesses was profitable, while the retail marketing business lost $71.3 million, due primarily to removing from retail certain of its wholesale supply contracts and the support from the competitive generation business. The sale of the retail business on June 1, 2006 ended virtually all of NU's exposure to this business.

The financial reliability of Select Energy's counterparties and its ability to manage its wholesale marketing portfolio of contracts and assets within acceptable risk parameters will be of material importance to Select Energy until these contracts are divested. The net fair value position of the wholesale portfolio that is marked-to-market at September 30, 2006 was a net liability of $146.3 million.

Exiting from Select Energy's remaining wholesale obligations could have an adverse impact on NU's liquidity, although any negative effect will be mitigated by the sale of the competitive generating assets. To date, most of Select Energy's contract terminations have been on terms where Select Energy settled with its counterparty for a sum of money and obtained a full release from further liability on the contract. One significant wholesale contract settlement was, and future contract terminations may be, negotiated on terms whereby Select Energy's obligations are assigned or transferred to a credit-worthy third party, but a release from Select Energy's customer is not obtained. In such circumstances, Select Energy or another NU company will be liable to the customer should the third party default. Any such contingent liabilities could remain open for extended periods of time.

Risks Related to Liquidity and Collateral Calls

NU's senior unsecured debt ratings by Moody's Investors Service and Standard & Poor's, Inc. are currently Baa2 and BBB-, respectively, with stable outlooks. Were either of these ratings to decline to sub-investment grade level, Select Energy could be asked to provide, as of September 30, 2006, approximately $152.3 million of collateral or LOCs to unaffiliated counterparties and approximately $65.1 million to several independent system operators and unaffiliated LDCs and LDCs under agreements largely guaranteed by NU. In addition, at September 30, 2006, Select Energy could have been requested to provide $2.7 million of collateral under certain contracts which counterparties have not required to date. While NU's credit facilities are in amounts that would be adequate to meet calls at that level, NU's ability to meet any future calls would depend on its liquidity and access to bank lines of credit and the capital markets at such time.

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, 2006.

ITEM 6.

EXHIBITS

Document designated with a (*) are filed herewith.

(a)

Listing of Exhibits (NU)

Exhibit No.

Description

*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 8, 2006

*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 8, 2006

*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 8, 2006

Listing of Exhibits (CL&P)

*4.12.6

Letter Amendment dated July 21, 2006 to Amended and Restated Receivables Purchase and Sales Agreement dated as of September 30, 1997, as amended and restated as of March 30, 2001

*31

Certification of Cheryl W. Grisé, 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 8, 2006

*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 8, 2006

*32

Certification of Cheryl W. Grisé, 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 8, 2006

Listing of Exhibits (PSNH)

*31

Certification of Cheryl W. Grisé, 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 8, 2006

*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 8, 2006

*32

Certification of Cheryl W. Grisé, 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 8, 2006

Listing of Exhibits (WMECO)

*31

Certification of Cheryl W. Grisé, 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 8, 2006

*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 8, 2006

*32

Certification of Cheryl W. Grisé, 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 8, 2006

SIGNATURE

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

NORTHEAST UTILITIES
Registrant

Date: November 8, 2006 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

THE CONNECTICUT LIGHT AND POWER COMPANY
Registrant

Date: November 8, 2006 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
Registrant

Date: November 8, 2006 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

SIGNATURE

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

WESTERN MASSACHUSETTS ELECTRIC COMPANY
Registrant

Date: November 8, 2006 By /s/ David R. McHale
David R. McHale
Senior Vice President and Chief Financial Officer
(for the Registrant and as Principal Financial Officer)

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