NORTHEAST UTILITIES
Form 10-Q/A
March 15, 2005
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q/A
Amendment No. 1

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

For the Quarterly Period Ended September 30, 2004

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

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Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days:

	Yes	No
	ü	

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act):

	Yes	No
Northeast Utilities	ü	

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

Company - Class of Stock	Outstanding at October 31, 2004
Northeast Utilities	
Common stock, $5.00 par value	128,384,407 shares

FORM 10-Q/A EXPLANATORY NOTE

This Amendment No. 1 to our quarterly report on Form 10-Q (Form 10-Q/A) is being filed to amend the quarterly report on Form 10-Q for the quarter ended September 30, 2004 of Northeast Utilities (NU), which was originally filed on November 5, 2004 (Original Form 10-Q). Accordingly, pursuant to rule 12b-15 under the Securities Exchange Act of 1934, as amended, this Form 10-Q/A contains the complete text of Items 1, 2, and 4 of Part I and Item 6 of Part II, as amended, as well as certain currently dated certifications. Unaffected items from the quarterly reports of separate registrants The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (and associated certifications) have not been repeated in this Form 10-Q/A.

Subsequent to the filing of the Form 10-Q for the quarter ended September 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. The natural gas basis contracts were originally accounted for on the accrual basis. The natural gas futures and swaps contracts were accounted for as cash flow hedges with changes in fair value reflected in other comprehensive income (a component of shareholders equity). However, subsequent to the filing of the third quarter report on Form 10-Q, NU concluded that applying accrual accounting for the basis contracts was incorrect. The basis contracts should have been recorded at current fair value with changes in fair value impacting earnings. The fair value was a negative $0.9 million at June 30, 2004 and at September 30, 2004 is a negative $2.7 million, which is now reflected in non-trading derivative liabilities. Fuel, purchased and net interchange power expenses increased by $1.8 million for the third quarter of 2004 and increased by $2.7 million for the nine-month period ended September 30, 2004 as a result of the restatements. The futures and swaps contracts should not have been accounted for as cash flow hedges and should also have been recorded at fair value. The fair value was a positive $2.7 million at June 30, 2004 and at September 30, 2004 is a negative $71.1 million. These amounts have been removed from other comprehensive income (a component of shareholders equity). Fuel, purchased and net interchange power expenses increased by $73.8 million for the third quarter and increased by $71.1 million for the nine-month period ended September 30, 2004 as a result of the restatements. This Form 10-Q/A reflects the change from accrual and hedge accounting to fair value accounting for the

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aforementioned natural gas derivative contracts. The net income impact of both of these restatements is a negative $47 million for the third quarter and a negative $45.9 million for the nine months ended September 30, 2004.

The natural gas contracts discussed above are accounted for at fair value with changes in fair value included in earnings. NU concluded that fair value or mark-to-market accounting should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of September 30, 2004, the condensed consolidated statements of income for the three and nine months ended September 30, 2004, and the condensed consolidated statement of cash flows for the nine months ended September 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments.

For December 31, 2003 amounts, corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, special deposits and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds were unrestricted and were used to or were available to fund the company s operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities. For information regarding this restatement and the effects on significant financial statement line items, see Note 9, Restatement of Previously Issued Financial Statements, to the condensed consolidated financial statements.

This amendment does not otherwise reflect events occurring after the filing of the Original Form 10-Q, which was filed on November 5, 2004. Such events include, among others, the events described in NU s current reports on Form 8-K filed after the filing of the Original Form 10-Q, except for those pertaining to this subject matter. Earnings guidance is not included in this Form 10-Q/A. For information regarding NU s most recent earnings guidance, see the current reports on Form 8-K dated January 26, 2005 and February 4, 2005.

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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
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company
NU or the company	Northeast Utilities
NU Enterprises	NU s competitive subsidiaries comprised of HWP, NGC, NGS, Select Energy, SESI, and Woods Network. For further information, see Note 8, Segment Information, to the condensed consolidated financial statements.
PSNH	Public Service Company of New Hampshire
RMS	R. M. Services
Select Energy	Select Energy, Inc. (including its wholly owned subsidiary SENY)
SENY	Select Energy New York, Inc.
SESI	Select Energy Services, Inc.
Utility Group	NU s regulated utilities comprised of CL&P, PSNH, WMECO, and Yankee Gas. For further information, see Note 8, Segment Information, to the condensed consolidated financial statements.
WMECO	Western Massachusetts Electric Company
Woods Network	Woods Network Services, Inc.
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

THIRD PARTIES:

Bechtel	Bechtel Power Corporation
CY	Connecticut Yankee
NRG	NRG Energy, Inc.

REGULATORS:

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

OTHER:

Act, the	Public Act No. 03-135
CTA	Competitive Transition Assessment
EPS	Earnings Per Share
FASB	Financial Accounting Standards Board
FMCC	Federally Mandated Congestion Costs
GSC	Generation Service Charge
ISO-NE	New England Independent System Operator
kWh	Kilowatt-Hour
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LOCs	Letters of Credit

MW	Megawatts

NU 2003 Form 10-K	The Northeast Utilities and Subsidiaries combined 2003 Form 10-K as filed with the SEC
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
OCC	Office of Consumer Counsel
Restructuring Settlement	"Agreement to Settle PSNH Restructuring"
ROE	Return on Equity
RTO	Regional Transmission Organization
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SFAS	Statement of Financial Accounting Standards
SMD	Standard Market Design
TS	Transition Energy Service
TSO	Transitional Standard Offer

NORTHEAST UTILITIES AND SUBSIDIARIES

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NORTHEAST UTILITIES AND SUBSIDIARIES

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004 (Restated)*	December 31, 2003 (Restated)*
	(Thousands of Dollars)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 97,852	$ 43,372
Restricted cash - LMP costs		93,630
Special deposits	101,688	79,120
Investments in securitizable assets	212,521	166,465
Receivables, less provision for uncollectible accounts of $41,538 in 2004 and $40,846 in 2003	656,384	704,893
Unbilled revenues	99,408	125,881
Fuel, materials and supplies, at average cost	202,760	154,076
Derivative assets	364,707	249,117
Prepayments and other	66,042	63,780
	1,801,362	1,680,334
Property, Plant and Equipment:		
Electric utility	5,792,149	5,465,854
Gas utility	776,391	743,990
Competitive energy	911,940	885,953
Other	239,663	221,986
	7,720,143	7,317,783
Less: Accumulated depreciation	2,357,086	2,244,263
	5,363,057	5,073,520
Construction work in progress	376,428	356,396

	5,739,485	5,429,916
Deferred Debits and Other Assets:		
Regulatory assets	2,802,912	2,974,022
Goodwill	319,986	319,986
Purchased intangible assets, net	20,251	22,956
Prepaid pension	356,540	360,706
Prior spent nuclear fuel trust	49,110	
Other	448,043	428,567
	3,996,842	4,106,237
Total Assets	$11,537,689	$11,216,487

* See Note 9.

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004 (Restated)*	December 31, 2003 (Restated)*
	(Thousands of Dollars)	
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 1,043	$ 105,000
Long-term debt - current portion	88,963	64,936
Accounts payable	704,559	728,463
Accrued taxes	3,111	51,598
Accrued interest	58,560	41,653
Derivative liabilities	206,557	112,612
Counterparty deposits	67,356	46,496
Other	207,878	203,080
	1,338,027	1,353,838
Rate Reduction Bonds	1,591,944	1,729,960
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,404,391	1,287,354
Accumulated deferred investment tax credits	100,062	102,652
Deferred contractual obligations	423,236	469,218
Regulatory liabilities	1,163,773	1,164,288

Other	244,692	247,526
	3,336,154	3,271,038
Capitalization:		
Long-Term Debt	2,839,694	2,481,331
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200
Common Shareholders Equity:		
Common shares, $5 par value - authorized 225,000,000 shares; 150,683,698 shares issued and 128,349,411 shares outstanding in 2004 and 150,398,403 shares issued and 127,695,999 shares outstanding in 2003	753,418	751,992
Capital surplus, paid in	1,111,152	1,108,924
Deferred contribution plan - employee stock ownership plan	(63,831)	(73,694)
Retained earnings	833,237	808,932
Accumulated other comprehensive income	40,754	25,991
Treasury stock, 19,575,940 shares in 2004 and 19,518,023 shares in 2003	(359,060)	(358,025)
Common Shareholders Equity	2,315,670	2,264,120
Total Capitalization	5,271,564	4,861,651
Commitments and Contingencies (Note 4)		
Total Liabilities and Capitalization	$ 11,537,689	$ 11,216,487

* See Note 9.

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004 (Restated)*	2003	2004 (Restated)*	2003
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 1,667,985	$ 1,640,117	$ 5,030,938	$ 4,554,338
Operating Expenses:				

Operation-				
Fuel, purchased and net interchange power	1,107,113	1,033,663	3,196,842	2,766,268
Other	273,838	232,616	798,048	672,435
Maintenance	52,919	45,339	150,855	139,110
Depreciation	57,232	50,879	167,366	151,044
Amortization	42,679	56,407	100,057	139,710
Amortization of rate reduction bonds	43,286	40,729	124,579	115,232
Taxes other than income taxes	55,360	53,169	188,644	178,603
Total operating expenses	1,632,427	1,512,802	4,726,391	4,162,402
Operating Income	35,558	127,315	304,547	391,936
Interest Expense:				
Interest on long-term debt	34,940	32,010	101,676	93,496
Interest on rate reduction bonds	24,446	26,863	75,184	82,088
Other interest	4,086	4,474	12,530	10,835
Interest expense, net	63,472	63,347	189,390	186,419
Other Income, Net	8,168	4,678	12,717	6,008
(Loss)/Income Before Income Tax (Benefit)/Expense	(19,746)	68,646	127,874	211,525
Income Tax (Benefit)/Expense	(13,228)	23,277	40,179	76,304
(Loss)/Income Before Preferred Dividends of Subsidiary	(6,518)	45,369	87,695	135,221
Preferred Dividends of Subsidiary	1,390	1,390	4,169	4,169
(Loss)/Income Before Cumulative Effect of Accounting Change	(7,908)	43,979	83,526	131,052
Cumulative effect of accounting change, net of tax benefit of $2,553		(4,741)		(4,741)
Net (Loss)/Income	$ (7,908)	$ 39,238	$ 83,526	$ 126,311
Basic and Fully Diluted (Loss)/Earnings Per Common Share:				
(Loss)/Income Before Cumulative Effect of Accounting Change	$ (0.06)	$ 0.35	$ 0.65	$ 1.03
Cumulative effect of accounting change, net of tax benefit		(0.04)		(0.04)
Basic and Fully Diluted (Loss)/Earnings Per Common Share	$ (0.06)	$ 0.31	$ 0.65	$ 0.99
Basic Common Shares Outstanding (average)	128,279,814	127,167,690	128,064,364	126,976,161
Fully Diluted Common Shares Outstanding (average)	128,442,701	127,303,973	128,231,267	127,086,414

* See Note 9.

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2004 (Restated)*	2003
	(Thousands of Dollars)	
Operating Activities:		
Income before preferred dividends of subsidiary	$ 87,695	$ 135,221
Adjustments to reconcile to net cash flows provided by operating activities:		
Depreciation	167,366	151,044
Deferred income taxes and investment tax credits, net	65,133	(55,734)
Amortization	100,057	139,710
Amortization of rate reduction bonds	124,579	115,232
Deferral of recoverable energy costs	(30,688)	(23,021)
Decrease/(increase) in prepaid pension	4,166	(23,778)
Cumulative effect of accounting change		(4,741)
Regulatory (refunds)/overrecoveries	(43,919)	122,870
Mark-to-market on natural gas contracts	45,916	
Other sources of cash	62,026	14,911
Other uses of cash	(42,710)	(105,914)
Changes in current assets and liabilities:		
Restricted cash - LMP costs	93,630	(45,760)
Receivables and unbilled revenues, net	74,982	160,789
Fuel, materials and supplies	(48,684)	(40,548)
Investments in securitizable assets	(46,056)	(36,684)
Other current assets	(85,163)	(5,703)
Accounts payable	(23,904)	10,805
Accrued taxes	(48,487)	(72,851)
Other current liabilities	69,545	24,906
Net cash flows provided by operating activities	525,484	460,754
Investing Activities:		
Investments in property and plant:		
Electric, gas and other utility plant	(449,785)	(369,660)
Competitive energy assets	(13,915)	(12,221)
Cash flows used for investments in property and plant	(463,700)	(381,881)
Buyout/buydown of IPP contracts		(20,437)
Investment in prior spent nuclear fuel trust	(49,110)	
Other investment activities	(32,843)	6,582
Net cash flows used in investing activities	(545,653)	(395,736)
Financing Activities:		
Issuance of common shares	4,470	9,940
Repurchase of common shares		(23,209)
Issuance of long-term debt	463,113	250,384

Retirement of rate reduction bonds	(138,016)	(126,374)
Decrease in short-term debt	(103,957)	(16,000)
Reacquisitions and retirements of long-term debt	(86,628)	(33,607)
Cash dividends on preferred stock of subsidiaries	(4,169)	(4,169)
Cash dividends on common shares	(59,221)	(53,959)
Other financing activities	(943)	(4,564)
Net cash flows provided by/(used in) financing activities	74,649	(1,558)
Net increase in cash and cash equivalents	54,480	63,460
Cash and cash equivalents - beginning of period	43,372	54,678
Cash and cash equivalents - end of period	$ 97,852	$ 118,138

* See Note 9.

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

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NORTHEAST UTILITIES AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (All Companies)

A. Presentation

Restatement of Previously Issued Financial Statements: Subsequent to the filing of the Form 10-Q for the quarter ended September 30, 2004, Northeast Utilities (NU or the company) concluded that it incorrectly applied accrual accounting for certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that fair value accounting should have been applied. To correct this error, the financial and other information included herein has been restated for this change. For December 31, 2003 amounts, corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, special deposits, accounts payable, derivative assets, and derivative liabilities, which had no impact on net income. For further information regarding this restatement and the effects on significant financial statement line items, see Note 9, Restatement of Previously Issued Financial Statements.

The accompanying unaudited condensed consolidated financial statements should be read in conjunction with this complete report on Form 10-Q/A, the First and Second Quarter 2004 reports on Form 10-Q, the Second Quarter 2004 report on Form 10-Q/A and the Annual Reports of NU, 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 NU 2003 Form 10-K, and the current reports on Form 8-K disclosed in Part II, Item 6, Other Information - Exhibits and Reports on Form 8-K, included in this report on Form 10-Q/A. The accompanying condensed consolidated financial statements contain, in the opinion of management, all adjustments necessary to present fairly NUs and the above companies financial position at September 30, 2004, the results of operations for the three-month and nine-month periods ended September 30, 2004 and 2003, and condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2004 and 2003. All adjustments are of a normal, recurring nature except those described in Note 1B. Due primarily to the seasonality of NUs business and to the quarterly earnings profile of NU Enterprises merchant energy business segment in 2004, the results of operations and condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2004 and 2003, are not 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.

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

B. New Accounting Standards

*Other-Than-Temporary Impairments:*The Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued and later deferred the effective date of accounting guidance included in EITF Issue No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments. EITF Issue No. 03-1 provides guidance on how to evaluate and recognize an impairment loss that is other-than-temporary and could impact NUs investments in Acumentrics Corporation (Acumentrics) and NEON Communications, Inc. (NEON) upon its effective date. Certain accounting guidance included in EITF Issue No. 03-1 is not effective until the FASB issues additional guidance on this issue. EITF Issue No. 03-1 also requires certain annual disclosures that are effective for NUs December 31, 2004 annual report on Form 10-K.

For further information regarding NUs investments in Acumentrics and NEON, see Note 1H, Summary of Significant Accounting Policies - Other Investments, to the condensed consolidated financial statements.

C. Guarantees

NU provides credit assurance in the form of guarantees and letters of credit (LOCs) in the normal course of business, primarily for the financial performance obligations of NU Enterprises. NU would be required to perform under these guarantees in the event of non-performance by NU Enterprises, primarily Select Energy, Inc. (Select Energy). At September 30, 2004, the maximum level of exposure in accordance with FASB Interpretation No. (FIN) 45, Guarantors Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, under guarantees by NU, primarily on behalf of NU Enterprises, totaled $990.8 million. Additionally, NU had $113.6 million of LOCs issued for the benefit of NU Enterprises outstanding at September 30, 2004.

At September 30, 2004, NU had outstanding guarantees on behalf of the Utility Group of $11.2 million. This amount is included in the total outstanding NU guarantee exposure amount of $990.8 million.

Several underlying contracts that NU guarantees and certain surety bonds contain credit ratings triggers that would require NU to post collateral in the event that NUs credit ratings are downgraded below investment grade.

NU currently has authorization from the Securities and Exchange Commission (SEC) to provide up to $750 million of guarantees for NU Enterprises through June 30, 2007. The $11.2 million in guarantees to the Utility Group are subject to a separate $50 million SEC limitation apart from the current $750 million guarantee limit. The amount of guarantees outstanding for compliance with the SEC limit for NU Enterprises at September 30, 2004 is $422 million, which is calculated using different, more probabilistic and fair-value based criteria than the maximum level of exposure required to be disclosed under FIN 45. FIN 45 includes all exposures even though they are not reasonably likely to result in exposure to NU.

On October 19, 2004, the SEC authorized NU to issue guarantees of up to an aggregate $100 million through June 30, 2007 of the debt or other obligations of two of its subsidiaries, Northeast Utilities Service Company and Rocky River Realty Company. These companies provide certain specialized support and real estate services to the entire NU system and occasionally enter into transactions that require financial backing from NU parent.

D. Regulatory Accounting

The accounting policies of NU's 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution businesses of CL&P, WMECO and PSNH, along with PSNH's generation business and Yankee Gas' distribution business, continue to be cost-of-service rate regulated, and management believes that the application of SFAS No. 71 to those portions of the aforementioned companies continues to be appropriate. Management also believes that it is probable that NU's Utility Group companies will recover their 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.

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

	At September 30, 2004			
(Millions of Dollars)	NU Consolidated (1)	CL&P	PSNH	WMECO
Recoverable nuclear costs	$ 54.0	$ -	$ 30.6	$ 23.4
Securitized assets	1,526.0	1,025.4	432.7	67.9
Income taxes, net	317.3	208.1	39.3	56.8
Unrecovered contractual obligations	352.2	208.3	65.1	78.8
Recoverable energy costs	268.8	61.7	200.7	3.2
Other	284.6	64.7	156.8	10.6
Totals	$2,802.9	$1,568.2	$925.2	$ 240.7

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(Millions of Dollars)	At December 31, 2003 NU Consolidated (1)	CL&P	PSNH	WMECO
Recoverable nuclear costs	$ 82.4	$ 16.4	$ 33.3	$ 32.7
Securitized assets	1,664.0	1,123.7	465.3	75.0
Income taxes, net	253.8	140.9	44.2	60.1
Unrecovered contractual obligations	378.6	221.8	69.9	86.9
Recoverable energy costs	255.7	30.1	218.3	3.7
Other	339.5	140.1	138.4	9.8
Totals	$2,974.0	$1,673.0	$969.4	$ 268.2

(1) At September 30, 2004 and December 31, 2003, included in the table are $68.8 million and $63.4 million, respectively, of other regulatory assets, primarily associated with Yankee Gas' income taxes, net and other regulatory assets related to environmental clean-up costs and hardship receivables.

Additionally, NU had approximately $11.6 million and approximately $12 million of regulatory costs at September 30, 2004 and December 31, 2003, respectively, that are included in deferred debits and other assets - other on the accompanying condensed consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved by the applicable regulatory agency. Management believes these assets are recoverable in future rates.

As discussed in Note 4D, "Commitments and Contingencies - Deferred Contractual Obligations," a substantial portion of the unrecovered contractual obligations regulatory asset has not yet been approved for recovery. At this time management believes that these regulatory assets are probable of recovery.

Regulatory Liabilities: The Utility Group maintained $1.2 billion of regulatory liabilities at both September 30, 2004 and December 31, 2003. These amounts are comprised of the following:

(Millions of Dollars)	At September 30, 2004 NU Consolidated (1)	CL&P	PSNH	WMECO
Cost of removal	$ 331.8	$146.7	$ 88.2	$ 24.6
CTA, GSC and SBC overcollections	235.4	235.4	—	—
Cumulative deferral — SCRC	200.6	—	200.6	—
Regulatory liabilities offsetting Utility Group derivative assets	186.4	186.4	—	—
LMP overcollections	61.6	61.6	—	—
Other	148.0	81.3	24.4	6.8
Totals	$1,163.8	$711.4	$313.2	$ 31.4

(Millions of Dollars)	At December 31, 2003 NU Consolidated (1)	CL&P	PSNH	WMECO
Cost of removal	$ 334.0	$150.0	$ 88.0	$ 25.0

CTA, GSC and SBC overcollections	333.7	333.7		
Cumulative deferral SCRC	160.4		160.4	
Regulatory liabilities offsetting Utility Group derivative assets	116.9	115.4	1.5	
LMP overcollections	83.6	83.6		
Other	135.7	70.3	22.2	2.8
Totals	$1,164.3	$753.0	$272.1	$ 27.8

(1) At September 30, 2004 and December 31, 2003, included in the table are $107.8 million and $111.4 million, respectively, of other regulatory liabilities, associated with Yankee Gas cost of removal, deferred gas costs, pension and other regulatory liabilities.

E. 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:

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	For the Nine Months Ended	
(Millions of Dollars)	September 30, 2004	September 30, 2003
Borrowed funds	$3.1	$4.1
Equity funds	2.2	5.1
Totals	$5.3	$9.2
Average AFUDC rates	3.8%	4.2%

F. Equity-Based Compensation

NU maintains an Employee Stock Purchase Plan and other long-term, equity-based incentive plans under the Northeast Utilities Incentive Plan. NU accounts for these plans under the recognition and measurement principles of Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and related interpretations. No equity-based employee compensation cost for stock options is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share (EPS) if NU had applied the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, to equity-based employee compensation:

	For the Nine Months Ended	
(Millions of Dollars, except per share amounts)	September 30, 2004(Restated)	September 30, 2003
Net income, as reported	$83.5	$126.3
Total equity-based employee compensation expense determined under the fair value-based method for all awards, net of related tax effects	1.5	1.4
Pro forma net income	$82.0	$124.9
EPS:		
Basic and fully diluted as reported	$0.65	$ 0.99
Basic and fully diluted pro forma	$0.64	$ 0.98

Net income as reported includes $2.8 million and $1.2 million expensed for restricted stock and restricted stock units for the nine months ended September 30, 2004 and 2003, respectively. NU accounts for restricted stock in accordance with APB No. 25 and amortizes the intrinsic value of the award over the related service period.

NU assumes an income tax rate of 40 percent to estimate the tax effect on total equity-based employee compensation expense determined under the fair value-based method for all awards.

During the nine-month period ended September 30, 2004, no stock options were awarded.

On March 31, 2004, the FASB issued an exposure draft that, if finalized as proposed, would require NU to expense equity-based employee compensation under the fair value-based method. The FASB continues to redeliberate this exposure draft and has deferred the effective date of a final statement to July 1, 2005 from January 1, 2005. A final standard could be issued in the fourth quarter of 2004.

G. Sale of Customer Receivables

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, 2004 and December 31, 2003, CL&P had sold accounts receivable of $40 million and $80 million, respectively, to the financial institution with limited recourse through CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. At September 30, 2004, the reserve requirements calculated in accordance with the related Receivables Purchase and Sale Agreement were $8.7 million. This reserve amount is deducted from the amount of receivables eligible for sale at the time. Concentrations of credit risk to the purchaser under this agreement with respect to the receivables are limited due to CL&Ps diverse customer base within its service territory. At September 30, 2004, the amount of customer receivables sold to CRC by CL&P but not sold to the financial institution totaling $212.5 million are included in investments in securitizable assets on the accompanying condensed consolidated balance sheets. This amount would be excluded from CL&Ps assets in the event of CL&Ps bankruptcy. On July 7, 2004, CL&P renewed the arrangement with the financial institution through July 6, 2005.

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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.

H. Other Investments

Yankee Energy System, Inc. (Yankee) maintains a long-term note receivable from BMC Energy LLC (BMC), an operator of renewable energy projects. In late-March 2004, based on revised information that impacts undiscounted cash flow projections and fair value estimates, management determined that the fair value of the note receivable from BMC had declined and that the note was impaired. As a result, management recorded an after-tax investment write-down of $1.5 million ($2.5 million on a pre-tax basis) in the first quarter of 2004.

NU has an investment in the common stock of Acumentrics, a developer of fuel cell and power quality equipment. Based on revised information that affected the fair value of NU's investment, management determined that at June 30, 2004, the value of NU's investment declined and that the decline was other-than-temporary in nature. An after-tax investment write-down of $2.4 million ($3.8 million on a pre-tax basis) was recorded to reduce the carrying value of the investment to $3.8 million. NU also has an investment in Acumentrics debt securities totaling $2.2 million at September 30, 2004.

On June 30, 2004, Yankee sold virtually all of the assets and liabilities of R.M. Services, Inc. (RMS), a provider of consumer collection services, for $3 million. In conjunction with the sale in the second quarter of 2004, an estimated gain totaling $0.6 million was included as a gain from sale of RMS. As a result of adjustments to estimates recorded in conjunction with the sale during the third quarter of 2004, this gain was increased by $0.2 million and totals $0.8 million at September 30, 2004. For the three and six months ended June 30, 2004, RMS was consolidated into NU's condensed consolidated financial statements and had pre-tax losses totaling $0.7 million and $1.7 million, respectively. These amounts are recorded in other income - other, net on the accompanying condensed consolidated statements of income. For the three and six months ended June 30, 2003, which is before RMS was consolidated, Yankee recorded pre-tax investment write-downs totaling $1.1 million and $1.4 million, respectively, related to its investment in RMS.

These charges are included in Note 1L, "Summary of Significant Accounting Policies – Other Income," and in the Eliminations and Other segment in Note 8, "Segment Information," to the condensed consolidated financial statements.

NU has an investment in the common stock of NEON, a provider of optical networking services. On July 19, 2004, NEON and Globix Corporation (Globix) announced a definitive merger agreement in which Globix, an unaffiliated publicly-owned entity would acquire NEON for shares of Globix common stock. If the merger is consummated, then NU would receive 1.2748 shares of Globix common stock for each of the 1.8 million shares of NEON stock it owns. Management continues to evaluate the potential impact of the proposed merger on NU's investment in NEON, which had a carrying value of $9.9 million at September 30, 2004.

NU owns 49 percent of the common stock of Connecticut Yankee (CY) with a carrying value of $21 million at September 30, 2004. CY is involved in litigation over the termination of the decommissioning contract with Bechtel Power Corporation (Bechtel). Management believes that this litigation has not impaired the value of its investment in CY at September 30, 2004 but will continue to evaluate the impact of the litigation on NU's investment. For further information regarding the Bechtel litigation, see Note 4D, "Commitments and Contingencies - Deferred Contractual Obligations," to the condensed consolidated financial statements.

I. 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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J. Special Deposits

Special deposits represents amounts Select Energy has on deposit with unaffiliated counterparties and brokerage firms in the amount of $80.2 million and amounts included in escrow for Select Energy Services, Inc. (SESI) that have not been spent on construction projects of $21.5 million at September 30, 2004. Similar amounts totaled $24.5 million and $32 million, respectively, at December 31, 2003. Special deposits at December 31, 2003 also included $30.1 million in escrow that PSNH funded to acquire Connecticut Valley Electric Company, Inc. on January 1, 2004.

K. Restricted Cash LMP Costs

Restricted cash - LMP costs represented incremental locational marginal pricing (LMP) cost amounts that were collected by CL&P and deposited into an escrow account. At December 31, 2003, restricted cash - LMP costs totaled $93.6 million, and an additional $30 million was deposited in 2004. During the third quarter of 2004, $83 million of the account was paid to CL&Ps standard offer suppliers in accordance with the Federal Energy Regulatory Commission (FERC) approved Standard Market Design (SMD) settlement. The remaining $41 million was released from the escrow account in the third quarter and will be refunded to CL&Ps customers as a credit on bills from September to December of 2004.

L. Other Income

The pre-tax components of NUs other income items are as follows:

	For the Three Months Ended	
(Millions of Dollars)	September 30, 2004	September 30, 2003
Investment income	$ 6.3	$ 5.5
CL&P procurement fee	3.0	
AFUDC equity funds	0.3	1.8
Gain on sale of RMS	0.2	
Charitable donations	(0.4)	(0.4)
Other, net	(1.2)	(2.2)
Totals	$ 8.2	$ 4.7

	For the Nine Months Ended	
(Millions of Dollars)	September 30, 2004	September 30, 2003
Investment write-downs	$ (6.3)	$
Investment income	13.4	13.5
CL&P procurement fee	8.8	
AFUDC equity funds	2.2	5.1
Gain on sale of RMS	0.8	
Charitable donations	(1.7)	(3.1)
Other, net	(4.5)	(9.5)
Totals	$12.7	$ 6.0

M. Counterparty Deposits

Balances collected from counterparties resulting from Select Energys credit management activities totaled $67.4 million at September 30, 2004 and $46.5 million at December 31, 2003. 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 receive such cash collateral in an unrestricted manner is determined by the terms of Select Energys 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.

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

Derivatives that are utilized for trading purposes are recorded at fair value with changes in fair value included in earnings. Other contracts that are derivatives but do not meet the definition of a cash flow or fair value hedge and cannot be designated as normal purchases or normal sales are also 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, the changes in the fair value of the effective portion of those contracts are generally recognized in accumulated other comprehensive income until the underlying transactions occur. For contracts that meet the definition of a derivative but do not meet the hedging

requirements, and for the ineffective portion of contracts that meet the cash flow hedge requirements, the changes in fair value of those contracts are recognized currently in earnings. Derivative contracts designated as fair value hedges and the item they are hedging are both recorded at fair value on the condensed consolidated balance sheets. Derivative contracts that are entered into as a normal purchase or sale and are probable of resulting in physical delivery, and are documented as such, are recorded under accrual accounting.

For the nine months ended September 30, 2004, a negative $42.7 million, net of tax, was reclassified as an expense from other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized in earnings. Also during the third quarter of 2004, new cash flow hedge transactions were entered into that hedge cash flows through 2006. As a result of these new transactions and market value changes since January 1, 2004, accumulated other comprehensive income increased by $15.4 million, net of tax. Accumulated other comprehensive income at September 30, 2004, was a positive $40.2 million, net of tax (increase to equity), relating to hedged transactions, and it is estimated that a positive $36 million included in this net of tax balance will be reclassified as an increase to earnings within the next twelve months. Cash flows from hedge contracts are reported in the same category as cash flows from the underlying hedged transaction.

The restatements discussed in Note 9, Restatement of Previously Issued Financial Statements, resulted in $42.7 million being removed from accumulated other comprehensive income and being recognized as a decrease in earnings.

There was no material impact recognized in earnings for the ineffective portion of cash flow hedges. A pre-tax negative $4.2 million was recognized in earnings for the ineffective portion of fair value hedges. The changes in the fair value of both the fair value hedges and the natural gas inventory being hedged are recorded in fuel, purchased, and net interchange power on the accompanying condensed consolidated statements of income.

The tables below summarize the derivative assets and liabilities at September 30, 2004 and December 31, 2003. The business activities of NU Enterprises that result in the recognition of derivative assets include concentrations of credit risk to energy marketing and trading counterparties. At September 30, 2004, Select Energy has $174.4 million of derivative assets from trading, non-trading, and hedging activities. These assets are exposed to counterparty credit risk. However, a significant portion of these assets is contracted with investment grade rated counterparties or collateralized with cash. The amounts below do not include option premiums paid, which are recorded as prepayments and amounted to $4.4 million and $9.1 million related to energy trading activities and $9 million and $7.6 million related to marketing activities at September 30, 2004 and December 31, 2003, respectively. These amounts also do not include option premiums received, which are recorded as other current liabilities and amounted to $7 million and $12.2 million related to energy trading activities at September 30, 2004 and December 31, 2003, respectively, and $1.9 million related to marketing activities at September 30, 2004.

	At September 30, 2004		
(Millions of Dollars)	Assets	Liabilities	Total
NU Enterprises:			
Trading	$ 94.0	$ (71.0)	$ 23.0
Non-trading	3.3	(76.1)	(72.8)
Hedging	77.1	(10.0)	67.1
Utility Group - Gas:			
Non-trading	0.3	(0.1)	0.2
Hedging	3.0	—	3.0
Utility Group - Electric:			
Non-trading	186.3	(49.4)	136.9
NU Parent:			
Hedging	0.7	—	0.7
Total	$364.7	$ (206.6)	$158.1

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	At December 31, 2003		
(Millions of Dollars)	Assets	Liabilities	Total
NU Enterprises:			
Trading	$ 71.8	$ (39.3)	$ 32.5
Non-trading	1.6	(0.8)	0.8
Hedging	55.8	(12.7)	43.1
Utility Group - Gas:			
Non-trading	0.2	(0.2)	—
Hedging	2.8	—	2.8
Utility Group - Electric:			
Non-trading	116.9	(56.0)	60.9
NU Parent:			
Hedging	—	(3.6)	(3.6)
Total	$249.1	$ (112.6)	$136.5

NU Enterprises - Trading: To gather market intelligence and utilize this information in risk management activities for the wholesale marketing activities, Select Energy conducts limited energy trading activities in electricity, natural gas, and oil, and therefore, experiences net open positions. Select Energy manages these open positions with strict policies that limit its exposure to market risk and require daily reporting to management of potential financial exposures.

Derivatives used in trading activities are recorded at fair value and included in the condensed consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recognized in operating revenues in the condensed consolidated statements of income in the period of change. The net fair value positions of the trading portfolio at September 30, 2004 and at December 31, 2003 were assets of $23 million and $32.5 million, respectively.

Select Energy's trading portfolio includes New York Mercantile Exchange (NYMEX) futures, financial swaps, and options, the fair value of which is based on closing exchange prices; over-the-counter forwards, financial swaps, and options, the fair value of which is based on the mid-point of bid and ask market prices; and bilateral contracts for the purchase or sale of electricity or natural gas, the fair value of which is determined using available information from external sources. Select Energy's trading portfolio also includes transmission congestion contracts (TCC). The fair value of the TCCs included in the trading portfolio is based on published market data.

NU Enterprises - Non-Trading: Certain non-trading derivative contracts are used for delivery of energy related to Select Energy's wholesale and retail marketing activities. These contracts are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined. These contracts cannot be designated as normal purchases or sales either because they are included in the New York energy market that settles financially or because management did not elect the normal purchases and sales designation.

Market information for the TCCs classified as non-trading is not available, and those contracts cannot be reliably valued. Management believes the amounts paid for these contracts, which total $5.4 million at September 30, 2004, and $4.3 million at December 31, 2003 and are included in premiums paid, are equal to their fair value.

Other non-trading derivative contracts with September 30, 2004 fair values of negative $73.8 million are used to mitigate the risk of electricity price changes on Select Energy's fixed-price electricity purchase contracts. These derivatives do not meet criteria to be accounted for as cash flow hedges and are accounted for at fair value as non-trading contracts. The contracts are natural gas basis and natural gas futures and swaps contracts with fair values determined by prices provided by external sources and actively quoted markets. Select Energy held none of these contracts at December 31, 2003.

NU Enterprises - Hedging: Select Energy utilizes derivative financial and commodity instruments, including futures and forward contracts, to reduce market risk associated with fluctuations in the price of electricity and natural gas purchased to meet firm sales and purchase commitments to certain customers. Select Energy also utilizes derivatives, including price swap agreements, call and put option contracts, and futures and forward contracts to manage the market risk associated with a portion of its anticipated supply and delivery requirements. These derivatives have been designated as cash flow hedging instruments and are used to reduce the market risk associated with fluctuations in the price of electricity or natural gas. A derivative that hedges exposure to the variable cash flows of a forecasted transaction (a cash flow hedge) is initially recorded at fair value with changes in fair value recorded 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.

Select Energy maintains natural gas service agreements with certain customers to supply gas at fixed prices for terms extending through 2006. Select Energy has hedged its gas supply risk under these agreements through NYMEX futures contracts. Under these contracts, which also extend through 2006, the purchase price of a specified quantity of gas is effectively fixed over the term of the gas service agreements. At September 30, 2004 the NYMEX futures contracts had notional values of $88.3 million and were recorded at fair value as derivative assets of $18.9 million.

Select Energy also maintains various physical and financial instruments to hedge its electric and gas purchases and sales through 2006. These instruments include forwards, futures, options, financial collars, swaps and financial transmission rights (FTRs). These hedging contracts, which are valued at the mid-point of bid and ask market prices, were recorded as derivative assets of $58.2 million and derivative liabilities of $84.5 million at September 30, 2004.

Select Energy hedges certain amounts of natural gas inventory with gas futures, options and swaps, some of which are accounted for as fair value hedges. The changes in fair value of the futures, options and swaps were recorded as derivative liabilities of $0.4 million at September 30, 2004. During the third quarter, a change in the fair value of hedged natural gas inventory of a negative $4.3 million was recorded along with the change in the fair value of the hedge of a positive $0.1 million. In September 2004, certain of these fair value hedges were redesignated as cash flow hedges, and future changes in fair value will be included in other comprehensive income (equity), unless ineffective.

Utility Group - Gas - Non-Trading : Yankee Gas non-trading derivatives consist of peaking supply arrangements to serve winter load obligations and firm sales contracts with options to curtail delivery. These contracts are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined, because of the optionality in the contract terms. Non-trading derivatives at September 30, 2004 included assets of $0.3 million and liabilities of $0.1 million.

Utility Group - Gas - Hedging: Yankee Gas maintains a master swap agreement with a financial counterparty to purchase gas at fixed prices. Under this master swap agreement, the purchase price of a specified quantity of gas for an unaffiliated customer is effectively fixed over the term of the gas service agreements with that customer for a period not extending beyond 2005. At September 30, 2004 the commodity swap agreement had a notional value of $3.3 million and was recorded at fair value as a derivative asset of $3 million. The firm commitment contract that is hedged is also recorded as a liability on the accompanying condensed consolidated balance sheets, and changes in fair values of the hedge and firm commitment have offsetting impacts in earnings.

Utility Group - Electric - Non-Trading: CL&P has two independent power producer (IPP) contracts 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 to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The fair values of these IPP non-trading derivatives at September 30, 2004 include a derivative asset with a fair value of $186.3 million and a derivative liability with a fair value of $49.4 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 rates.

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. As a matched-terms fair value hedge, the changes in fair value of the swap and the hedged debt instrument are recorded on the condensed consolidated balance sheets but are equal and offsetting in the condensed consolidated statements of income. The cumulative change in the fair value of the hedged debt of $0.7 million is included an increase to long-term debt on the condensed consolidated balance sheets. The hedge is recorded as a derivative asset of $0.7 million. The resulting changes in interest payments made are recorded as adjustments to interest expense.

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

SFAS No. 142, Goodwill and Other Intangible Assets, requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount. There were no impairments or adjustments to the goodwill balances during the nine-month periods ended September 30, 2004 and 2003.

NUs reporting units that maintain goodwill are generally consistent with the operating segments underlying the reportable segments identified in Note 8, Segment Information, to the condensed consolidated financial statements. Consistent with

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the way management reviews the operating results of its reporting units, NUs reporting units under the NU Enterprises reportable segment include: 1) the merchant energy reporting unit and 2) the energy services reporting unit. The merchant energy reporting unit is comprised of the operations of Select Energy, Northeast Generation Company (NGC) and the generation operations of Holyoke Water Power Company (HWP), while the energy services reporting unit is comprised of the operations of SESI, Northeast Generation Services Company (NGS) and Woods Network Services, Inc. (Woods Network). As a result, NUs reporting units that maintain goodwill are as follows: the Yankee Gas reporting unit, which is classified under the Utility Group - gas reportable segment; the merchant energy reporting unit, which is classified under the NU Enterprises - merchant energy reportable segment; and the energy services reporting unit, which is classified under NU Enterprises - eliminations and other. The goodwill balances of these reporting units are included in the table herein.

At September 30, 2004, NU maintained $319.9 million of goodwill that is no longer being amortized, $11.7 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. At December 31, 2003, NU maintained $319.9 million of goodwill that is no longer being amortized, $14.4 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. A summary of NUs goodwill balances at September 30, 2004 and December 31, 2003, by reportable segment and reporting unit is as follows:

(Millions of Dollars)	At September 30, 2004	At December 31, 2003
Utility Group Gas:		
Yankee Gas	$287.6	$287.6
NU Enterprises:		
Merchant Energy	3.2	3.2
Energy Services	29.1	29.1
Totals	$319.9	$319.9

The goodwill recorded related to the acquisition of Yankee Gas is not being recovered from the customers of Yankee Gas.

At September 30, 2004 and December 31, 2003, NUs intangible assets and related accumulated amortization, all of which related to NU Enterprises, consisted of the following:

	At September 30, 2004

(Millions of Dollars)	Gross Balance	Accumulated Amortization	Net Balance
Intangible assets subject to amortization:			
Exclusivity agreement	$17.7	$ 9.2	$ 8.5
Customer list	6.6	3.4	3.2
Totals	$24.3	$12.6	$11.7
Intangible assets not subject to amortization:			
Customer relationships	$ 5.2		
Tradenames	3.3		
Totals	$ 8.5		

	At December 31, 2003		
(Millions of Dollars)	Gross Balance	Accumulated Amortization	Net Balance
Intangible assets subject to amortization:			
Exclusivity agreement	$17.7	$7.2	$10.5
Customer list	6.6	2.7	3.9
Totals	$24.3	$9.9	$14.4
Intangible assets not subject to amortization:			
Customer relationships	$ 5.2		
Tradenames	3.3		
Totals	$ 8.5		

NU recorded amortization expense of $2.7 million and $2.6 million for the nine months ended September 30, 2004 and 2003, respectively, related to intangible assets. Based on the current amount of intangible assets subject to amortization, the estimated annual amortization expense for 2004 and for each of the succeeding 5 years from 2005 through 2009 is $3.6 million in 2004 through 2007 and no amortization expense in 2008 or 2009. These amounts may vary as acquisitions and dispositions occur in the future.

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4. COMMITMENTS AND CONTINGENCIES

A. Regulatory Issues and Rate Matters (CL&P, PSNH, WMECO)

Connecticut:

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

On April 1, 2004, CL&P filed its 2003 CTA and SBC reconciliation with the Connecticut Department of Public Utility Control (DPUC), which compares CTA and SBC revenues to revenue requirements. A final decision in the 2003 CTA and SBC docket was issued on August 4, 2004 and ordered a refund to customers of $88.5 million over a seven-month period beginning with October 2004 consumption.

The DPUC also directed CL&P to impute revenues of $2.7 million during 2004 payable to customers associated with a previously renegotiated IPP contract. On September 15, 2004, CL&P filed an appeal and a motion for partial stay with the Connecticut Superior Court challenging the DPUC s August 4, 2004 decision regarding this contract. The motion for partial stay was granted. On October 15, 2004, CL&P entered into a settlement involving the counterparties to this contract and various other parties. If approved by the DPUC and by the bankruptcy court of one of the counterparties, the DPUC will rescind the imputed revenues order, and CL&P would withdraw its appeal. CL&P is awaiting approvals of the settlement.

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P s request, and on October 24, 2003, CL&P appealed the DPUC s final decision to the Connecticut Superior Court. The appeal has been fully briefed and is in the argument phase, and a decision from the Connecticut Superior Court could be rendered by the end of 2004. If CL&P s request is granted through these court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

New Hampshire:

SCRC Reconciliation Filing: The stranded cost recovery charge (SCRC) allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the New Hampshire Public Utilities Commission (NHPUC) a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and transition energy service (TS) revenues billed with TS costs. The NHPUC reviews the filing, including a prudence review of PSNH s generation operations. The cumulative deferral of SCRC revenues in excess of costs was $200.6 million at September 30, 2004. This cumulative deferral will decrease the amount of non-securitized stranded costs that will have to be recovered from PSNH s customers in the future from $422.6 million to $222 million.

The 2003 SCRC reconciliation filing was filed with the NHPUC on April 30, 2004, and a proposed stipulation and settlement agreement between PSNH, the Office of Consumer Advocate and NHPUC staff was filed with the NHPUC on October 4, 2004. Under the terms of the settlement agreement, no costs related to the recovery of stranded costs or the cost of providing TS were disallowed, and the NHPUC staff agreed to accept the 2003 SCRC filing without change. On October 29, 2004, the NHPUC issued an order accepting the settlement agreement as filed.

Estimated unbilled revenues are not included in the reconciliation of billed revenues to incurred costs through rate mechanisms for the SCRC and the TS. At September 30, 2004, the unbilled balance related to SCRC and TS was $11.7 million and $16.7 million, respectively. The level of the TS rate will vary from time to time and will continue until it is replaced with Default Energy Service, or some equivalent, which will then continue indefinitely. The SCRC rate is expected to begin decreasing in late 2006. Management will seek from regulators a determination as to the ultimate inclusion of any of this unbilled revenue into billed rates.

Massachusetts:

Transition Cost Reconciliation: On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy. This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The timing of a final decision is uncertain, but management does not expect the outcome of this docket to have a material adverse impact on WMECO s net income 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 of its subsidiaries filed voluntary bankruptcy petitions. On December 5, 2003, NRG emerged from bankruptcy. NU s NRG-related exposures as a result of these transactions relate to 1) the recovery of congestion charges incurred by NRG prior to the implementation of SMD on March 1, 2003, 2) the recovery of CL&P s station service billings from NRG, and 3) the recovery of Yankee Gas and CL&P s expenditures that were incurred related to an NRG subsidiary s generating plant construction project that is now abandoned. While it is unable to determine the ultimate outcome of these issues, management does not expect that their resolution will have a material adverse effect on NU s consolidated financial condition or results of operations.

C. Long-Term Contractual Arrangements (CL&P, PSNH, WMECO, Yankee Gas, and Select Energy)

Select Energy maintains long-term agreements to purchase energy in the normal course of business as part of its portfolio of resources to meet its actual or expected sales commitments. The aggregate amount of these purchase contracts was $5.4 billion at September 30, 2004, as follows (millions of dollars):

Year	
2004	$ 1,460.9
2005	2,914.6
2006	452.7
2007	125.7
2008	89.0
Thereafter	312.5
Total	$ 5,355.4

Select Energy s purchase contract amounts can exceed the amount expected to be reported in fuel, purchased and net interchange power as energy trading purchases are classified net with the corresponding revenues.

The following are material updates to the table of contractual obligations and commercial commitments discussed in NU s 2003 report on Form 10-K:

(Millions of Dollars)	2004	2005	2006	2007	2008	Thereafter
Contracted expenditures for construction of Yankee Gas LNG facility	$ 7.5	$ 30.6	$ 39.3	$ 3.4	$	$
Northern Wood Project	21.6	36.5	5.6			
FERC-approved billings from the Yankee Companies	40.8	92.5	74.4	68.6	60.9	113.5
	$69.9	$159.6	$119.3	$72.0	$60.9	$ 113.5

Certain other estimated construction expenditures totaling $19.2 million related to the Yankee Gas liquefied natural gas (LNG) facility and $11.3 million related to the Northern Wood Project are not included in the contracts signed to build these facilities and are not included in the table above. NU s other long-term contractual arrangements have not changed materially from the amounts reported at December 31, 2003.

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

NU still has significant decommissioning and plant closure cost obligations to the companies that own the Yankee Atomic (YA), CY and Maine Yankee (MY) nuclear power plants (collectively, 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 CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. YA has received FERC approval to collect all presently estimated decommissioning costs. MY and various other parties filed a settlement agreement with the FERC, which provides for the collection of approximately $27 million annually through October 31, 2008 for all presently estimated decommissioning and long-term spent fuel storage costs. The MY settlement was approved by the FERC on September 16, 2004.

CY s estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised

estimate reflects the fact that CY is now self-performing all work to complete the decommissioning of the plant due to the termination of the decommissioning contract with Bechtel in July 2003, the increases in the projected costs of spent fuel storage, and increased security and liability and property insurance costs. NU s share of CY s increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CY filed with the FERC for recovery of these increased costs. In the filing, CY sought 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 beginning on February 1, 2005, subject to refund, and scheduled hearings for May 2005. In total, NU s estimated remaining decommissioning and plant closure obligation for CY is $310.2 million at September 30, 2004.

On June 10, 2004, the DPUC and Office of Consumer Counsel (OCC) filed a petition seeking a declaratory order that CY 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. On August 30, 2004, the FERC denied this petition. On September 29, 2004, the DPUC and OCC asked the FERC to reconsider the petition. On October 29, 2004, the FERC issued an order granting further consideration regarding the DPUC s and OCC s petition for reconsideration. No hearing date has been established.

CY is currently in litigation with Bechtel over the termination of its decommissioning contract. On June 13, 2003, CY gave notice of the termination of its contract with Bechtel for the decommissioning of its nuclear power plant. CY terminated the contract due to Bechtel s history of incomplete and untimely performance and refusal to perform the remaining decommissioning work. Bechtel has departed the site and the decommissioning responsibility has been transitioned to CY, which has recommenced the decommissioning process.

On June 23, 2003, Bechtel filed a complaint against CY asserting a number of claims and seeking a variety of remedies, including monetary and punitive damages and rescission of the contract. Bechtel has since amended its complaint to add claims for wrongful termination. On August 22, 2003, CY filed its answer and counterclaims, including counts for breach of contract, negligent misrepresentation and breach of duty of good faith and fair dealing. Discovery is currently underway and a trial has been scheduled for May 2006.

On July 20, 2004, the Connecticut Superior Court (the Court) allowed the DPUC to intervene in the prejudgment remedy (PJR) proceeding filed in June 2004 for the limited purpose of objecting to Bechtel s requested garnishment of the decommissioning trust and related payments. On October 27, 2004, Bechtel and CY entered into a stipulation under which Bechtel relinquished its right to seek garnishment of the decommissioning trust and related payments in return for the potential attachment of CY s real property in Connecticut and the escrowing of $41.7 million the sponsors are scheduled to pay to CY through June 30, 2007. This stipulation is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. CY intends to contest the attachability of such assets. Management cannot predict the outcome of this litigation or its impact on NU.

NU cannot at this time predict the timing or outcome of the FERC proceeding required for the collection of the increased decommissioning costs. Management believes that the costs have been prudently incurred and will ultimately be recovered from the customers of CL&P, PSNH and WMECO. However, there is a risk that some portion of these increased costs may not be recovered, or will have to be refunded if recovered, as a result of the FERC proceedings. NU also cannot predict the timing and the outcome of the litigation with Bechtel.

The Yankee Companies also are seeking recovery of damages from the United States Department of Energy (DOE) for the cost of storing spent nuclear fuel that the DOE has failed to remove. The DOE trial ended on August 30, 2004 and a verdict has not been reached. The related claim for damages from the DOE incurred through 2010 is approximately $500 million. The current Yankee Companies rates do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

For additional current information regarding these issues and litigation with Bechtel, see Part II, Item 1, Legal Proceedings, in this report on Form 10-Q.

E. Consolidated Edison, Inc. Merger Litigation

Certain gain and loss contingencies continue to exist with regard to the 1999 merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation. Interrogatory appeals in the case are now pending, and no trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU. For additional information on this litigation, see Part II, Item 1, Legal Proceedings in this report on Form 10-Q.

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5. COMPREHENSIVE INCOME (NU, CL&P, PSNH, WMECO, NU Enterprises)

Total comprehensive income, which includes all comprehensive income/(loss) items by category, for the nine months ended September 30, 2004 and 2003 is as follows:

	Nine Months Ended September 30, 2004 (Restated - See Note 9)					
	NU	CL&P	PSNH	WMECO	NU Enterprises	Other
Net income*	$83.5	$65.1	$36.0	$ 8.7	$ (20.2)	$(6.1)
Comprehensive income/(loss) items:						
Qualified cash flow hedging instruments	15.4				15.3	0.1
Unrealized losses on securities	(0.6)					(0.6)
Net change in comprehensive income/(loss) items	14.8				15.3	(0.5)
Total comprehensive income/(loss)	$98.3	$65.1	$36.0	$ 8.7	$ (4.9)	$(6.6)

	Nine Months Ended September 30, 2003					
	NU	CL&P	PSNH	WMECO	NU Enterprises	Other
Net income*	$126.3	$59.0	$34.5	$ 13.9	$ 24.0	$(5.1)
Comprehensive income/(loss) items:						
Qualified cash flow hedging instruments	(18.7)				(14.7)	(4.0)
Unrealized losses on securities	1.0	0.1	0.1			0.8

Net change in comprehensive income/(loss) items	(17.7)	0.1	0.1		(14.7)	(3.2)
Total comprehensive income/(loss)	$ 108.6	$ 59.1	$ 34.6	$ 13.9	$ 9.3	$ (8.3)

*After preferred dividends of subsidiary.

NU s total comprehensive income for the three months ended September 30, 2004 and 2003 totaled $12.2 million in losses and $34.6 million in income, respectively.

Amounts included in the Other column primarily relate to NU parent and Northeast Utilities Service Company.

Accumulated other comprehensive income fair value adjustments in NU s qualified cash flow hedging instruments for the three and nine months ended September 30, 2004 and the twelve months ended December 31, 2003 are as follows:

(Millions of Dollars, Net of Tax)	Three Months September 30, 2004	Nine Months September 30, 2004	Twelve Months December 31, 2003
Balance at beginning of period	$ 44.1	$ 24.8	$ 15.5
Hedged transactions recognized into earnings	(15.5)	(42.7)	(5.3)
Change in fair value	8.3	45.0	5.0
Cash flow transactions entered into for the period	3.3	13.1	9.6
Net change associated with the current period hedging transactions	(3.9)	15.4	9.3
Total fair value adjustments included in accumulated other comprehensive income	$ 40.2	$ 40.2	$ 24.8

Accumulated other comprehensive income items unrelated to NU s qualified cash flow hedging instruments totaled $0.6 million and $1.2 million in gains at September 30, 2004 and December 31, 2003, respectively. These amounts primarily relate to unrealized gains on investments in marketable debt and equity securities, net of related income taxes.

6. EARNINGS PER SHARE (NU)

EPS is computed based upon the weighted average number of common shares outstanding 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. At September 30, 2004 and 2003, 647,856 options and 2,004,224 options, respectively, were excluded from the following table as these options were antidilutive. The following table sets forth the components of basic and fully diluted EPS:

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	Nine Months Ended September 30,	
(Millions of Dollars, Except for Share Information)	2004 (Restated)	2003

Income before preferred dividends of subsidiaries	$ 87.7	$ 135.2
Preferred dividends of subsidiaries	4.2	4.2
Income before cumulative effect of accounting change	$ 83.5	$ 131.0
Cumulative effect of accounting change, net of tax benefit		(4.7)
Net income	$ 83.5	$ 126.3
Basic EPS common shares outstanding (average)	128,064,364	126,976,161
Dilutive effects of employee stock options	166,903	110,256
Fully diluted EPS common shares outstanding (average)	128,231,267	127,086,417
Basic and fully diluted EPS:		
Income before cumulative effect of accounting change	$ 0.65	$ 1.03
Cumulative effect of accounting change net of tax benefit		(0.04)
Net income	$ 0.65	$ 0.99

7. 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 the majority of 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/(income) for the Pension Plan and the PBOP Plan for the nine months ended September 30, 2004 and 2003 are estimated as follows:

	For the Nine Months Ended September 30,			
	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2004	2003	2004	2003
Service cost	$ 30.5	$ 26.3	$ 4.5	$ 4.0
Interest cost	89.2	87.7	19.0	20.1
Expected return on plan assets	(131.3)	(136.9)	(9.4)	(11.2)
Amortization of unrecognized net transition (asset)/obligation	(1.1)	(1.1)	8.9	8.9
Amortization of prior service cost	5.4	5.4	(0.3)	(0.3)
Amortization of actuarial loss/(gain)	11.5	(5.3)		
Other amortization, net			8.6	4.8
Total - net periodic expense/(income)	$ 4.2	$ (23.9)	$31.3	$ 26.3

A portion of these expenses/(income) is capitalized related to employees working on capital projects.

NU does not expect to make any contributions to the Pension Plan in 2004. NU anticipates contributing approximately $10.4 million quarterly totaling $41.7 million in 2004 to fund its PBOP Plan.

Based on the most recent actuarial valuation as of January 1, 2004, the impact of the Medicare program has been revised from a $20 million decrease in the PBOP benefit obligation at December 31, 2003 to $27 million at September 30, 2004. The total $27 million decrease consists of $20 million as a direct result of the subsidy for certain non-capped retirees and $7 million related to changes in participation assumptions for capped retirees and future retirees as a result of the subsidy. The total $27 million decrease is currently being amortized as a reduction to PBOP expense over approximately 13 years. For the nine months ended September 30, 2004, this reduction in PBOP expense totaled approximately $2.8 million, including amortization of the actuarial gain of $1.5 million and a reduction in interest cost based on a lower PBOP benefit obligation of $1.3 million.

As a result of litigation with nineteen former employees, in April 2004, NU was ordered by the court to modify its retirement plan to include special retirement benefits for fifteen of these former employees retroactive to the dates of their retirement and increased future monthly benefit payments. In the third quarter, NU withdrew its appeal of the court s ruling. As a consequence, benefits with an estimated cost of $2.1 million will be provided to these fifteen former employees. This amount will be recorded as a plan amendment, which will be amortized as a prior service cost and will increase pension expense over approximately 13 years.

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8. SEGMENT INFORMATION (All Companies)

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 they operate. Based on enhanced information that is reviewed by NU s chief operating decision maker, separate detailed information regarding the Utility Group s transmission businesses and NU Enterprises merchant energy business is now included in the following segment information. Segment information for all periods has been restated to conform to the current presentation except for total asset information for the transmission business segment.

The Utility Group segment, including both the regulated electric distribution and transmission businesses, as well as the gas distribution business comprised of Yankee Gas, represents approximately 69 percent and 73 percent of NU s total revenues for the nine months ended September 30, 2004 and 2003, respectively, and includes the operations of the regulated electric utilities, CL&P, PSNH and WMECO, whose complete condensed consolidated financial statements are included in NU s 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 Select Energy, NGC, the generation operations of HWP, and their respective subsidiaries, while the NU Enterprises eliminations and other business segment includes SESI, NGS, Woods Network, and their respective subsidiaries and intercompany eliminations. The results of NU Enterprises parent are also included within eliminations and other.

Effective January 1, 2004, Select Energy began serving a portion of CL&P s transitional standard offer (TSO) load for 2004. Total Select Energy revenues from CL&P for CL&P s standard offer load, TSO load and for other transactions with CL&P, represented approximately $474.9 million or 22 percent for the nine months ended September 30, 2004 and approximately $566.2 million or 30 percent for the nine months ended September 30, 2003, of total NU Enterprises revenues. Total CL&P purchases from Select Energy are eliminated in consolidation.

Additionally, WMECO s purchases from Select Energy for standard offer and default service and for other transactions with Select Energy represented approximately $81.5 million and $110.3 million of total NU Enterprises revenues for the nine months ended September 30, 2004 and 2003, respectively. Total WMECO purchases from Select Energy are eliminated in consolidation. Select Energy revenues related to contracts with NSTAR companies represented $251.6 million or 12 percent of total NU Enterprises revenues for the nine months ended September 30, 2004. Select Energy also provides BGS in the New Jersey market. Select Energy revenues related to these contracts represented $238.5 million or 11 percent of total NU Enterprises revenues for the nine months ended September 30, 2004 and $323.6 million or 17 percent for the nine months ended September 30, 2003. No other individual customer represented in excess of 10 percent of NU Enterprises revenues for the nine months ended September 30, 2004 or 2003.

Eliminations and other in the NU consolidated tables includes the results for Mode 1 Communications, Inc., an investor in NEON, the results of the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, RMS, Yankee Energy Financial Services, and NorConn Properties, Inc.), the non-energy operations of HWP, the results of NU s parent and service companies, and write-downs of certain of the company s investments. Interest expense included in eliminations and other primarily relates to the debt of NU parent. Inter-segment eliminations of revenues and expenses are also included in eliminations and other. Eliminations and other includes NU s investment in RMS. Virtually all of the assets and liabilities of RMS were sold on June 30, 2004.

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NU s segment information for the three months and nine months ended September 30, 2004 and 2003 is as follows (some amounts between segment schedules may not agree due to rounding):

	For the Nine Months Ended September 30, 2004					
	Utility Group					
	Distribution					
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Eliminations and Other	Totals
Operating revenues	$ 3,061.4	$ 291.4	$ 105.4	$ 2,156.4	$ (583.7)	$ 5,030.9
Depreciation and amortization	(340.2)	(19.4)	(16.2)	(14.5)	(1.7)	(392.0)
Other operating expenses	(2,474.5)	(250.9)	(48.6)	(2,141.3)	580.9	(4,334.4)
Operating income/(loss)	246.7	21.1	40.6	0.6	(4.5)	304.5
Interest expense, net	(118.4)	(12.7)	(8.7)	(39.4)	(10.2)	(189.4)
Other income/(loss), net	10.9	(0.8)	(0.3)	5.3	(2.4)	12.7
Income tax (expense)/benefit	(48.8)	0.9	(8.0)	13.3	2.5	(40.1)
Preferred dividends	(4.2)					(4.2)
Net income/(loss)	$ 86.2	$ 8.5	$ 23.6	$ (20.2)	$ (14.6)	$ (83.5)
Total assets (1)	$ 8,359.6	$ 1,072.8	$	$ 2,110.0	$ (4.7)	$ 11,537.7
Total investments in plant	$ 281.3	$ 37.1	$ 120.9	$ 13.9	$ 10.5	$ 463.7

(1) Information for segmenting total assets between electric distribution and transmission is not available at September 30, 2004. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution column above.

	For the Three Months Ended September 30, 2004					
	Utility Group					
	Distribution					
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Eliminations and Other	Totals
Operating revenues	$ 1,037.7	$ 48.2	$ 40.8	$ 739.0	$ (197.7)	$ 1,668.0
Depreciation and amortization	(124.9)	(6.6)	(6.1)	(4.9)	(0.7)	(143.2)
Other operating expenses	(827.8)	(45.7)	(18.3)	(795.4)	197.9	(1,489.3)
Operating income/(loss)	85.0	(4.1)	16.4	(61.3)	(0.5)	35.5

Interest expense, net	(39.2)	(4.3)	(3.0)	(13.5)	(3.5)	(63.5)
Other income/(loss), net	3.9	(0.2)	(0.2)	2.4	2.3	8.2
Income tax (expense)/benefit	(17.9)	5.0	(2.2)	29.4	(1.0)	13.3
Preferred dividends	(1.4)					(1.4)
Net income/(loss)	$ 30.4	$ (3.6)	$ 11.0	$ (43.0)	$ (2.7)	$ (7.9)

	For the Nine Months Ended September 30, 2003					
	Utility Group					
	Distribution					
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Eliminations and Other	Totals
Operating revenues	$ 2,998.5	$ 253.7	$ 88.5	$ 1,903.4	$ (689.8)	$ 4,554.3
Depreciation and amortization	(358.4)	(17.2)	(13.9)	(14.8)	(1.7)	(406.0)
Other operating expenses	(2,372.0)	(219.1)	(39.4)	(1,814.3)	688.4	(3,756.4)
Operating income/(loss)	268.1	17.4	35.2	74.3	(3.1)	391.9
Interest expense, net	(125.5)	(9.9)	(3.9)	(36.6)	(10.5)	(186.4)
Other income/(loss), net	2.2	(1.4)	(0.1)	4.2	1.1	6.0
Income tax (expense)/benefit	(54.8)	(2.7)	(9.6)	(17.9)	8.7	(76.3)
Preferred dividends	(4.2)					(4.2)
Income/(loss) before cumulative effect of accounting change	85.8	3.4	21.6	24.0	(3.8)	131.0
Cumulative effect of accounting change, net of tax benefit					(4.7)	(4.7)
Net income/(loss)	$ 85.8	$ 3.4	$ 21.6	$ 24.0	$ (8.5)	$ 126.3
Total investments in plant	$ 255.3	$ 37.4	$ 64.5	$ 12.2	$ 12.5	$ 381.9

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For the Three Months Ended September 30, 2003

	Utility Group					
	Distribution					
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Eliminations and Other	Totals
Operating revenues	$ 1,104.5	$ 30.6	$ 32.7	$ 735.3	$ (263.1)	$ 1,640.0
Depreciation and amortization	(132.3)	(5.8)	(4.7)	(4.6)	(0.6)	(148.0)
Other operating expenses	(871.5)	(19.5)	(11.6)	(707.2)	245.1	(1,364.7)
Operating income/(loss)	100.7	5.3	16.4	23.5	(18.6)	127.3
Interest expense, net	(41.7)	(3.4)	(1.1)	(13.5)	(3.7)	(63.4)
Other income/(loss), net	2.7	(0.4)		1.3	1.1	4.7
Income tax (expense)/benefit	(23.3)	(11.1)	(5.5)	(4.4)	21.0	(23.3)
Preferred dividends	(1.4)					(1.4)
Income/(loss) before cumulative effect of accounting change	37.0	(9.6)	9.8	6.9	(0.2)	43.9
Cumulative effect of accounting change, net of tax benefit					(4.7)	(4.7)
Net income/(loss)	$ 37.0	$ (9.6)	$ 9.8	$ 6.9	$ (4.9)	$ 39.2

Utility Group segment information related to the regulated electric distribution and transmission businesses for CL&P, PSNH and WMECO for the three months and nine months ended September 30, 2004 and 2003 is as follows:

	CL&P - For the Nine Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 2,083.4	$ 69.9	$ 2,153.3
Depreciation and amortization	(170.5)	(11.4)	(181.9)
Other operating expenses	(1,761.0)	(32.0)	(1,793.0)
Operating income	151.9	26.5	178.4
Interest expense, net	(75.4)	(6.3)	(81.7)
Other income, net	15.3	(0.2)	15.1
Income tax expense	(38.0)	(4.5)	(42.5)
Preferred dividends	(4.2)		(4.2)
Net income	$ 49.6	$ 15.5	$ 65.1
Total investments in plant	$ 180.1	$ 98.9	$ 279.0

	CL&P - For the Three Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 699.4	$ 26.1	$ 725.5
Depreciation and amortization	(56.9)	(3.9)	(60.8)
Other operating expenses	(587.9)	(11.9)	(599.8)
Operating income	54.6	10.3	64.9
Interest expense, net	(24.6)	(2.3)	(26.9)
Other income, net	5.2	(0.1)	5.1

Income tax expense	(19.2)	(0.8)	(20.0)
Preferred dividends	(1.4)		(1.4)
Net income	$ 14.6	$ 7.1	$ 21.7

	CL&P - For the Nine Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 2,061.3	$ 57.7	$ 2,119.0
Depreciation and amortization	(225.6)	(10.4)	(236.0)
Other operating expenses	(1,681.9)	(26.1)	(1,708.0)
Operating income	153.8	21.2	175.0
Interest expense, net	(82.1)	(2.8)	(84.9)
Other income, net	4.8	(0.2)	4.6
Income tax expense	(26.8)	(4.7)	(31.5)
Preferred dividends	(4.2)		(4.2)
Net income	$ 45.5	$ 13.5	$ 59.0
Total investments in plant	$ 176.5	$ 45.9	$ 222.4

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	CL&P - For the Three Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 775.8	$ 22.1	$ 797.9
Depreciation and amortization	(76.6)	(3.5)	(80.1)
Other operating expenses	(639.1)	(7.5)	(646.6)
Operating income	60.1	11.1	71.2
Interest expense, net	(27.4)	(0.8)	(28.2)
Other income, net	2.6		2.6
Income tax expense	(11.3)	(3.9)	(15.2)
Preferred dividends	(1.4)		(1.4)
Net income	$ 22.6	$ 6.4	$ 29.0

	PSNH - For the Nine Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals

Operating revenues	$ 705.3	$ 24.2	$ 729.5
Depreciation and amortization	(139.6)	(3.4)	(143.0)
Other operating expenses	(493.0)	(11.4)	(504.4)
Operating income	72.7	9.4	82.1
Interest expense, net	(32.6)	(1.3)	(33.9)
Other income, net	(3.3)	(0.1)	(3.4)
Income tax expense	(6.7)	(2.1)	(8.8)
Net income	$ 30.1	$ 5.9	$ 36.0
Total investments in plant	$ 70.5	$ 18.3	$ 88.8

	PSNH - For the Three Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 247.7	$ 11.2	$ 258.9
Depreciation and amortization	(58.1)	(1.7)	(59.8)
Other operating expenses	(164.2)	(4.5)	(168.7)
Operating income	25.4	5.0	30.4
Interest expense, net	(11.1)	(0.5)	(11.6)
Other income, net	(1.2)		(1.2)
Income tax expense	1.4	(0.8)	0.6
Net income	$ 14.5	$ 3.7	$ 18.2

	PSNH - For the Nine Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 650.8	$ 19.3	$ 670.1
Depreciation and amortization	(81.9)	(2.2)	(84.1)
Other operating expenses	(481.5)	(8.7)	(490.2)
Operating income	87.4	8.4	95.8
Interest expense, net	(33.8)	(0.7)	(34.5)
Other income, net	(3.6)		(3.6)
Income tax expense	(20.4)	(2.8)	(23.2)
Net income	$ 29.6	$ 4.9	$ 34.5
Total investments in plant	$ 59.6	$ 17.3	$ 76.9

	PSNH - For the Three Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals

Operating revenues	$ 229.4	$ 6.6	$ 236.0
Depreciation and amortization	(39.1)	(0.8)	(39.9)
Other operating expenses	(158.8)	(2.5)	(161.3)
Operating income	31.5	3.3	34.8
Interest expense, net	(11.3)	(0.2)	(11.5)
Other income, net	(1.2)		(1.2)
Income tax expense	(8.5)	(1.0)	(9.5)
Net income	$ 10.5	$ 2.1	$ 12.6

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	WMECO - For the Nine Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 272.9	$ 11.3	$ 284.2
Depreciation and amortization	(30.1)	(1.4)	(31.5)
Other operating expenses	(220.7)	(5.2)	(225.9)
Operating income	22.1	4.7	26.8
Interest expense, net	(10.3)	(1.0)	(11.3)
Other income, net	(1.1)	(0.1)	(1.2)
Income tax expense	(4.1)	(1.5)	(5.6)
Net income	$ 6.6	$ 2.1	8.7
Total investments in plant	$ 21.6	$ 3.7	$ 25.3

	WMECO - For the Three Months Ended September 30, 2004		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 90.7	$ 3.5	$ 94.2
Depreciation and amortization	(10.0)	(0.5)	(10.5)
Other operating expenses	(75.7)	(1.9)	(77.6)
Operating income	5.0	1.1	6.1
Interest expense, net	(3.4)	(0.3)	(3.7)
Other income, net	(0.2)	(0.1)	(0.3)
Income tax expense	(0.1)	(0.5)	(0.6)

Net income	$ 1.3	$ 0.2	$ 1.5

	WMECO - For the Nine Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 286.3	$ 11.5	$ 297.8
Depreciation and amortization	(50.7)	(1.3)	(52.0)
Other operating expenses	(208.7)	(4.6)	(213.3)
Operating income	26.9	5.6	32.5
Interest expense, net	(9.6)	(0.4)	(10.0)
Other income, net	1.0		1.0
Income tax expense	(7.6)	(2.0)	(9.6)
Net income	$ 10.7	$ 3.2	$ 13.9
Total investments in plant	$ 19.2	$ 1.3	$ 20.5

	WMECO - For the Three Months Ended September 30, 2003		
(Millions of Dollars)	Distribution	Transmission	Totals
Operating revenues	$ 99.3	$ 4.1	$ 103.4
Depreciation and amortization	(16.6)	(0.5)	(17.1)
Other operating expenses	(73.5)	(1.7)	(75.2)
Operating income	9.2	1.9	11.1
Interest expense, net	(3.0)	(0.1)	(3.1)
Other income, net	1.2		1.2
Income tax expense	(3.4)	(0.6)	(4.0)
Net income	$ 4.0	$ 1.2	$ 5.2

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NU Enterprises segment information for the three months and nine months ended September 30, 2004 and 2003 is as follows. Eliminations are included in the services and other column:

	NU Enterprises - For the Nine Months Ended September 30, 2004
	Services

(Millions of Dollars)	Merchant Energy	and Other	Totals
Operating revenues	$ 1,949.1	$ 207.3	$ 2,156.4
Depreciation and amortization	(13.0)	(1.5)	(14.5)
Other operating expenses	(1,934.5)	(206.8)	(2,141.3)
Operating income	1.6	(1.0)	0.6
Interest expense, net	(32.8)	(6.6)	(39.4)
Other (loss)/income, net	(0.1)	5.4	5.3
Income tax expense	12.4	0.9	13.3
Net loss	$ (18.9)	$ (1.3)	$ (20.2)
Total assets	$ 1,793.3	$ 320.4	$ 2,113.7
Total investments in plant	$ 13.0	$ 0.9	$ 13.9

	NU Enterprises - For the Three Months Ended September 30, 2004		
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$ 664.1	$ 74.9	$ 739.0
Depreciation and amortization	(4.4)	(0.5)	(4.9)
Other operating expenses	(721.8)	(73.6)	(795.4)
Operating (loss)/income	(62.1)	0.8	(61.3)
Interest expense, net	(11.2)	(2.3)	(13.5)
Other income, net		2.4	2.4
Income tax benefit/(expense)	29.6	(0.2)	29.4
Net (loss)/income	$ (43.7)	$ 0.7	$ (43.0)

	NU Enterprises - For the Nine Months Ended September 30, 2003		
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$ 1,731.1	$ 172.3	$ 1,903.4
Depreciation and amortization	(13.2)	(1.6)	(14.8)
Other operating expenses	(1,646.0)	(168.3)	(1,814.3)
Operating income	71.9	2.4	74.3
Interest expense, net	(31.2)	(5.4)	(36.6)
Other (loss)/income, net	(2.5)	6.7	4.2
Income tax expense	(15.9)	(2.0)	(17.9)
Net income	$ 22.3	$ 1.7	$ 24.0
Total investments in plant	$ 12.2	$	$ 12.2

NU Enterprises - For the Three Months Ended September 30, 2003			
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$ 675.9	$ 59.4	$ 735.3
Depreciation and amortization	(4.5)	(0.1)	(4.6)
Other operating expenses	(648.6)	(58.6)	(707.2)
Operating income	22.8	0.7	23.5
Interest expense, net	(11.2)	(2.3)	(13.5)
Other (loss)/income, net	(0.3)	1.6	1.3
Income tax expense	(4.4)		(4.4)
Net income	$ 6.9	$	$ 6.9

9. RESTATEMENT OF PREVIOUSLY ISSUED FINANCIAL STATEMENTS *(NU, Select Energy)*

Subsequent to the filing of the Form 10-Q for the quarter ended September 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that

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fair value accounting for the aforementioned natural gas derivative contracts should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of September 30, 2004, the condensed consolidated statements of income for the three and nine months ended September 30, 2004, and the condensed consolidated statement of cash flows and the condensed consolidated statement of comprehensive income for the nine months ended September 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments.

For December 31, 2003 amounts, corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, special deposits and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds are unrestricted and were used to or were available to fund the company s operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities.

The effects of the revisions on the condensed consolidated balance sheets as of September 30, 2004, and December 31, 2003, the condensed consolidated statements of income and the condensed consolidated statement of comprehensive income for the three and nine months ended September 30, 2004, and the condensed consolidated statement of cash flows for the nine months ended September 30, 2004 are summarized in the following tables (in thousands, except share information):

Condensed Consolidated Balance Sheets	At September 30, 2004	
	Previously Reported	As Restated
Derivative assets	$ 368,470	$ 364,707
Derivative liabilities	207,656	206,557

Accumulated deferred income taxes	1,403,816	1,404,391
Retained earnings	879,153	833,237
Accumulated other comprehensive (loss)/income	(1,923)	40,754

	At December 31, 2003	
	Previously Reported	As Restated
Cash and cash equivalents	$ 37,196	$ 43,372
Unrestricted cash from counterparties	46,496	
Special deposits	86,636	79,120
Derivative assets	301,194	249,117
Accounts payable	768,783	728,463
Derivative liabilities	164,689	112,612

Condensed Consolidated Statements of Income	Three Months Ended September 30, 2004		Nine Months Ended September 30, 2004	
	Previously Reported	As Restated	Previously Reported	As Restated
Fuel, purchased and net interchange power	$ 1,031,540	$ 1,107,113	$ 3,123,051	$ 3,196,842
Income/(loss) before income tax expense/(benefit)	55,827	(19,746)	201,665	127,874
Income tax expense/(benefit)	15,320	(13,228)	68,054	40,179
Income/(loss) before preferred dividends of subsidiaries	40,507	(6,518)	133,611	87,695
Income/(loss) before cumulative effect of accounting change	39,117	(7,908)	129,442	83,526
Net income/(loss)	$ 39,117	$ (7,908)	$ 129,442	$ 83,526
Basic and fully diluted earnings/(loss) per common share:				
Income/(loss) before cumulative effect of accounting change	$ 0.30	$ (0.06)	$ 1.01	$ 0.65
Basic and fully diluted earnings/(loss) per common share	$ 0.30	$ (0.06)	$ 1.01	$ 0.65

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Condensed Consolidated Statement of Cash Flows	Nine Months Ended September 30, 2004	
	Previously Reported	As Restated
Income before preferred dividends of subsidiary	$133,611	$ 87,695
Adjustments to reconcile net cash flows provided by operating activities:		
Mark-to-market on natural gas contracts		45,916
Other sources of cash	61,451	62,026
Other current assets	(82,874)	(85,163)
Accounts payable	(24,769)	(23,904)

Accrued taxes	(47,023)	(48,487)
Other current liabilities	73,883	69,545
Other operating activities	417,856	417,856
Net cash flows provided by operating activities	532,135	525,484
Net increase in cash and cash equivalents	61,131	54,980
Cash and cash equivalents - beginning of period	$ 36,721	$ 43,372

Additionally, NU s total comprehensive income for the three and nine months ended September 30, 2004, which was previously reported as $9.4 million in losses and $98.4 million, respectively, has been restated and now totals $12.2 million in losses and $98.3 million, respectively.

Condensed Consolidated Statement of Comprehensive Income	Nine Months Ended September 30, 2004	
	Previously Reported	As Restated
Net income	$ 129.4	$ 83.5
Comprehensive income/(loss) items:		
Qualified cash flow hedging instruments	(30.4)	15.4
Unrealized loss on securities	(0.6)	(0.6)
Net change in comprehensive income/(loss) items	(31.0)	14.8
Total comprehensive income	$ 98.4	$ 98.3

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NORTHEAST UTILITIES AND SUBSIDIARIES

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

FORM 10-Q/A EXPLANATORY NOTE

Subsequent to the filing of the Form 10-Q for the quarter ended September 30, 2004, NU concluded that it incorrectly applied accrual accounting for certain natural gas contracts established by the merchant energy segment to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. NU concluded that fair value, or mark-to-market, accounting should have been applied. To correct this error, NU restated its condensed consolidated balance sheet as of September 30, 2004, the condensed consolidated statements of income for the three and nine months ended September 30, 2004, and the condensed consolidated statement of cash flows for the nine months ended September 30, 2004. NU has also restated the notes to its condensed consolidated financial statements as necessary to reflect the adjustments.

For December 31, 2003 amounts, corrections have been made to cash and cash equivalents, unrestricted cash from counterparties, special deposits and accounts payable, which had no impact on net income. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds are unrestricted and were used to or were available to fund the company s operations. The December 31, 2003 condensed consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities. For information regarding this restatement and the effects on significant financial statement line items, see Note 9, Restatement of Previously Issued Financial Statements, to the condensed consolidated financial statements. This Management s Discussion and Analysis of Financial Condition and Results of Operations gives effect to this restatement.

This amendment does not otherwise reflect events occurring after the filing of the Original Form 10-Q, which was filed on November 5, 2004. Such events include, among others, the events described in NU s current reports on Form 8-K filed after the filing of the Original Form 10-Q, except for those reports pertaining to this subject matter. Earnings guidance is not included in this Form 10-Q/A. For information regarding NU s most recent earnings guidance, see the current reports on Form 8-K dated January 26, 2005 and February 4, 2005.

This discussion should be read in conjunction with the condensed consolidated financial statements and footnotes in this Form 10-Q/A, the First Quarter 2004 Form 10-Q, the Second Quarter 2004 report on Form 10-Q/A, the NU 2003 Form 10-K, and the current reports on Form 8-K disclosed in Part II, Item 6, Other Information - Exhibits and Reports on Form 8-K, included in this report on Form 10-Q/A. 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 report on Form 10-Q:

Results and Outlook:

Earnings at Northeast Utilities (NU or the company) decreased by $47.1 million in the third quarter of 2004 compared with the same period of 2003, and decreased by $42.8 million for the first nine months of 2004 compared with the first nine months of 2003. The results for the third quarter of 2004 include the negative after-tax impact of $47 million related to the mark-to-market accounting for certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of wining certain levels of wholesale electric load in New England. Results in the third quarter of 2003 included a negative cumulative effect of an accounting change of $4.7 million associated with NU s former investment in a bill collection company.

Retail electric sales decreased 4.9 percent in the third quarter of 2004 compared with the third quarter of 2003 primarily as a result of the 2003 positive unbilled revenue adjustments. Absent these adjustments, revenues were virtually unchanged in the third quarter of 2004, compared with 2003. On a weather-adjusted basis, sales increased 2.8 percent as a result of improved economic conditions.

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Regulatory Items:

On August 4, 2004, the Connecticut Department of Public Utility Control (DPUC) issued a final decision on The Connecticut Light and Power Company s (CL&P) petition for reconsideration of the DPUC s December 2003 rate order in CL&P s distribution rate case. This decision had a $6 million positive impact on CL&P s earnings in the third quarter of 2004.

The City of Norwalk, Connecticut appealed the July 14, 2003 Connecticut Citing Council approval of the construction of a 345,000-volt transmission line from Bethel, Connecticut to Norwalk, Connecticut. On August 19, 2004, a Connecticut Superior Court judge dismissed the City of Norwalk s appeal.

A settlement agreement was approved on September 2, 2004 by the New Hampshire Public Utilities Commission (NHPUC) to raise Public Service Company of New Hampshire s (PSNH) retail distribution rates by $3.5 million annually, effective on October 1, 2004 and $10 million annually, effective on June 1, 2005.

On September 3, 2004, the DPUC approved the application of Yankee Gas Services Company (Yankee Gas) to construct a liquefied natural gas (LNG) storage facility in Waterbury, Connecticut, capable of storing the equivalent of 1.2 billion cubic feet of natural gas, with an estimated cost of approximately $100 million.

On September 15, 2004, the Federal Energy Regulatory Commission (FERC) approved a settlement agreement allowing the transmission business to implement a formula rate with an 11.0 percent return on equity (ROE). This ROE will remain in effect until the FERC establishes an ROE for a New England regional transmission organization (RTO).

On October 14, 2004, Yankee Gas filed a settlement agreement between Yankee Gas, the Office of Consumer Counsel (OCC) and the Prosecutorial Division of the DPUC in its rate case proceeding.

Liquidity:

On July 22, 2004, PSNH issued $50 million of 10-year first mortgage bonds at a fixed interest rate of 5.25 percent.

On September 17, 2004, CL&P issued $280 million of 10-year and 30-year first mortgage bonds at fixed interest rates of 4.8 percent and 5.75 percent, respectively.

On September 23, 2004, Western Massachusetts Electric Company (WMECO) issued $50 million of 30-year senior unsecured notes at a fixed interest rate of 5.9 percent.

NU s capital expenditures continue to be lower than initially projected for 2004. NU s capital expenditures totaled $463.7 million for the first nine months of 2004, compared with $381.9 million for the first nine months of 2003. NU s 2004 capital spending is now projected to total $638.4 million compared with the 2004 budget amount of $738 million. The lower projected capital spending amount is due primarily to delays in approvals of major transmission capital projects.

CL&P is required to return to customers past overcollections, including $88.5 million of Competitive Transition Assessment (CTA) and System Benefits Charge (SBC) amounts to be returned from October 2004 through April 2005, and $75 million of previously collected Standard Market Design (SMD) costs to be returned from September 2004 through December 2004. Also, $30 million of previous Generation Service Charge (GSC) overrecoveries each year will be used to recover costs in the years 2004 through 2007.

Overview

Consolidated: NU lost $7.9 million, or $0.06 per share, in the third quarter of 2004, compared with earnings of $39.2 million, or $0.31 per share, in the third quarter of 2003. For the first nine months of 2004, NU earned $83.5 million, or $0.65 per share, compared with $126.3 million, or $0.99 per share in the same period of 2003. Earnings in 2004 include the negative after-tax impact of $47 million related to the mark-to-market accounting for certain natural gas contracts. Earnings in 2003 included a cumulative effect of an accounting change of $4.7 million, or $0.04 per share, associated with NU s former investment in a bill collection company.

A summary of NU s earnings/(losses) by major business for the third quarter and first nine months of 2004 and 2003 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	2004	2003	2004	2003
Utility Group	$ 37.8	$ 37.2	$118.3	$110.8
NU Enterprises	(43.0)	6.9	(20.2)	24.0
Parent and other	(2.7)	(4.9)	(14.6)	(8.5)
Net (loss)/income	$ (7.9)	$ 39.2	$ 83.5	$126.3

NU s revenues during the first nine months of 2004 increased to $5 billion from $4.5 billion in the same period of 2003. The increase in revenues was primarily due to an increase of $377 million in revenues at NU Enterprises. This increase is the result of $171 million in higher revenues due to higher electric and gas prices and more of NU Enterprises revenues coming from companies that are not NU subsidiaries. An increase in volumes accounted for the remainder of that increase.

Utility Group: The Utility Group is comprised of CL&P, PSNH, WMECO, and Yankee Gas. Earnings at the Utility Group increased by $0.6 million in the third quarter of 2004 compared with the same period of 2003, and increased by $7.5 million for the first nine months of 2004 compared with the first nine months of 2003. The increase in earnings for the first nine months of 2004 was primarily due to increases in CL&P s retail rates and an overall lower Utility Group effective tax rate due to adjustments to tax reserves totaling $2.8 million as a result of the actual 2003 tax return amounts being compared to the 2003 year end tax provision estimates in the third quarter of 2004. The CL&P rate case reconsideration decision also had a positive impact on third quarter and year-to-date earnings. Those improvements were partially offset by lower pension income and higher interest and depreciation expense. A summary of Utility Group earnings/(losses) by company for the third quarter and first nine months of 2004 and 2003 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	2004	2003	2004	2003
CL&P *	$ 21.7	$ 29.0	$ 65.1	$ 59.0
PSNH	18.2	12.6	36.0	34.5
WMECO	1.5	5.2	8.7	13.9
Yankee Gas	(3.6)	(9.6)	8.5	3.4
Net income	$ 37.8	$ 37.2	$118.3	$110.8

* After preferred dividends.

CL&P s third quarter 2004 earnings were lower than the same period of 2003 primarily due to the absence of the positive 2003 adjustment to the estimate of unbilled revenues and milder weather in the third quarter of 2004. CL&P s higher year-to-date earnings resulted from distribution and transmission rate increases that took effect January 1, 2004. These higher retail rates were offset by higher depreciation expense and lower pension income. CL&P also benefited from the final decision on the reconsideration of CL&P s rate case, which had a third quarter 2004 positive pre-tax impact of approximately $10.2 million (approximately $6 million after-tax). The positive earnings impact included the recovery of $9.4 million in pension assets that were written off in the fourth quarter of 2003.

PSNH earnings were higher for the third quarter and year-to-date 2004, compared with the same period of 2003, primarily as a result of a lower effective tax rate. The lower effective tax rate is due to adjustments to tax reserves totaling a positive $5.4 million recorded in the third quarter of 2004 as a result of the actual 2003 tax return amounts being compared to the 2003 year end tax provision estimates. The lower effective tax rate is also due to the allocation of certain parent company tax benefits to PSNH in accordance with the NU tax allocation agreement. Under its tax allocation agreement, more tax benefits were allocated from NU parent to the Utility Group, including PSNH, in 2004 than in 2003.

WMECO s third quarter and year-to-date earnings were lower due to lower pension income and higher interest and depreciation expense, offset by a lower effective tax rate.

Yankee Gas third quarter and year-to-date 2004 results benefited from the absence of a negative $5.1 million adjustment to the estimate of unbilled revenues in the third quarter of 2003 and the reduction in income tax expense due to changes in estimates of deferred taxes associated with Yankee Gas plant assets that were recorded in the second quarter of 2004. Year-to-date results were also positively impacted by a change in rate design implemented in August 2003. Yankee Gas current rate design is intended to recover more costs based on stable, fixed monthly charges rather than based on variable, usage-based charges as was the rate design in place earlier in 2003. That shift from more variable to more fixed charges has reduced quarterly earnings in the higher-use first and fourth quarters and improved quarterly results in the lower-use second and third quarters compared to Yankee Gas previous rate design.

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Included in Utility Group earnings are earnings related to the transmission business. Transmission business earnings were $11 million in the third quarter of 2004 and $23.6 million for the first nine months of the year compared with earnings of $9.8 million in the third quarter of 2003 and $21.6 million for the first nine months of 2003. Transmission business earnings for the periods in 2004 are higher than the same periods in 2003 primarily due to higher revenues. Transmission revenues are higher in 2004 due to the implementation of a FERC approved formula rate resulting in increased rates. In the first nine months of 2004, $85 million of transmission projects were placed in service. The formula rate allows immediate recovery of these costs. During the first nine months of 2003, revenues were not subject to this formula rate.

NU Enterprises: NU Enterprises, Inc. is the parent company of Northeast Generation Company (NGC), Northeast Generation Services Company (NGS), Select Energy, Inc. (Select Energy), Select Energy Services, Inc. (SESI) and their respective subsidiaries, and Woods Network Services, Inc. (Woods Network), all of which are collectively referred to as NU Enterprises. The generation operations of Holyoke Water Power Company (HWP) are also included in the results of NU Enterprises. The companies included in the NU Enterprises segment are grouped into two business segments: the merchant energy segment and the energy services business segment. The merchant energy business segment is comprised of Select Energy s wholesale business, which includes approximately 1,293 megawatts (MW) of pumped storage and hydroelectric generation assets owned by NGC, 147 MW of coal-fired generation assets owned by HWP, and Select Energy s retail business. The energy services business consists of the operations of NGS, SESI and Woods Network.

NU Enterprises earnings decreased by $49.9 million in the third quarter of 2004 compared with the third quarter of 2003. Losses in 2004 include the negative after-tax impact of $47 million related to the mark-to-market accounting for certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of wining certain levels of wholesale electric load in New England. The decrease in third quarter profitability was also due to lower volumes and margins on wholesale contracts from seasonal pricing, offset by positive adjustments to income tax expense totaling $1.8 million and to a reduction in contract reserves totaling $1.1 million (after-tax). The seasonal pricing produced high margins in the first quarter of 2004 and lower margins in the remaining quarters. Cooler summer weather in 2004 contributed to the lower earnings in 2004 by reducing the sales volume during the quarter. The decrease in third quarter profitability was also due to net changes to the fair values of natural gas inventory and related hedges. This decrease amounted to $2.5 million (after-tax).

NU Enterprises earnings decreased by $44.2 million for the first nine months of 2004 compared with the first nine months of 2003. Merchant energy third quarter earnings included an after-tax negative $47 million related to changes in fair value of certain natural gas contracts established to mitigate the risk of electricity purchased in anticipation of wining certain levels of wholesale electric load in New England. The use of fair value accounting for these contracts has and will likely result in earnings volatility in future periods.

A summary of NU Enterprises earnings/(losses) by business for the third quarter and first nine months of 2004 and 2003 is as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(Millions of Dollars)	2004	2003	2004	2003
Merchant energy	$(43.7)	$6.9	$(18.9)	$22.3
Energy services and other	0.7		(1.3)	1.7
Net (loss)/income	$(43.0)	$6.9	$(20.2)	$24.0

The decreases in year-to-date earnings at the energy services business are due in part to a $1.8 million after-tax loss recorded in the second quarter on a construction contract and a reduced level of work for the United States government. For the period of September 30, 2003 to October 28, 2004, the United States government was precluded by statute from awarding certain energy savings contracts.

Parent and Other: For the three and nine months ended September 30, 2003, parent and other includes the $4.7 million negative cumulative effect of an accounting change associated with NU s former investment in a bill collection company. Absent that amount, parent and other resulted in decreases to NU s earnings of $2.5 million for the third quarter of 2004 compared to 2003, and $10.8 million for the first nine months of 2004 compared to 2003, primarily due to the allocation of income tax benefits from NU parent to subsidiaries.

Strategic Overview

In September 2004, management completed its comprehensive review of all its business lines and five-year business plans. The review was performed to identify the best opportunities in each business and determine how to allocate capital to those opportunities. This review resulted in a validation of key elements of the company s existing strategy and increased clarity in

how the company expects to invest capital over the next five years. The company has identified significant investment requirements in the Utility Group transmission and distribution businesses and expects to invest more than $3.7 billion in regulated electric and natural gas infrastructure from 2005 through 2009.

Based on current projections, management expects that the need to invest heavily in regulated infrastructure to meet reliability requirements and customer growth will cause NU s Utility Group distribution and generation rate base to rise from $2.5 billion in 2004 to nearly $3.9 billion by the end of 2009. Based on currently projected expenditures and capital project completion dates, management expects that the same factors will increase NU s Utility Group transmission rate base from approximately $500 million in 2004 to approximately $1.7 billion in 2009.

Management believes the company s Utility Group capital investments as currently scheduled, when added to projected dividend requirements, will result in net cash needs of approximately $4.4 billion from 2005 through 2009. Management believes that approximately $2.6 billion of that sum will be raised through internal sources with the remaining $1.8 billion coming from external sources. Management expects most of the external funding to be in the form of new debt issues and a substantially lesser amount to be in the form of new equity issues. Management does not have a firm schedule for the issuance of those securities, and the schedule is highly dependent on the timing of capital additions, among other things.

Labor Relations

On October 22, 2004, contracts offered by CL&P to employees represented by Locals 420 and 457 of the International Brotherhood of Electrical Workers were rejected by the unions. These two contracts cover approximately 1,200 CL&P employees, primarily physical workers including electricians, line workers, meter readers and installers, cable splicers, and warehouse personnel. Management cannot predict the outcome of contract negotiations or the ultimate impact, if any, of a possible strike.

Liquidity

Consolidated: NU continues to maintain an adequate level of liquidity. At September 30, 2004, NU had $97.9 million of cash and cash equivalents on hand compared with $43.4 million at December 31, 2003. The cash position of NU at September 30, 2004 includes $41 million of previously restricted cash collected for SMD costs that will be refunded to CL&P s customers.

NU s net cash flows provided by operating activities increased to $525.5 million in the first nine months of 2004 from $460.8 million in the first nine months of 2003 due to changes in working capital items and to changes in regulatory (refunds)/overrecoveries.

The release of restricted cash collected in 2003 associated with locational marginal pricing (LMP) costs but not yet paid to suppliers or refunded to customers, increased cash from operations in the first nine months of 2004. CL&P paid $83 million to its standard offer suppliers in accordance with the FERC-approved SMD settlement agreement, which decreased accounts payable. Another approximately $56 million will be refunded to customers related to the SMD settlement agreement in the fourth quarter of 2004 and will negatively impact cash flows from operations. An increase in counterparty deposits, which fluctuate based on changes in the fair value of certain energy contracts, resulted in an increase in other current liabilities and had a positive impact on cash flows from operations in the first nine months of 2004 compared to the same period in 2003.

The decrease in regulatory (refunds)/overrecoveries is primarily due to lower CTA and GSC collections in the first nine months of 2004 as NU refunds amounts to its ratepayers for past over collections or uses those amounts to recover current costs. These refunds are also the primary reason for the positive change in deferred income taxes for the first nine months of 2004 as compared to the first nine months of 2003, which has increased operating cash flows. The change in deferred income taxes is expected to continue to benefit cash flows from operations in 2004 due to bonus tax depreciation on newly completed plant assets.

On September 30, 2004, NU paid a dividend of $0.1625 per share. On October 12, 2004, the NU Board of Trustees approved a common dividend of $0.1625 per share, payable on December 30, 2004, to shareholders of record at December 1, 2004.

NU s capital expenditures have been lower than what had been expected at the beginning of 2004. NU s capital expenditures totaled $463.7 million for the first nine months of 2004, compared with $381.9 million for the first nine months of 2003. NU currently projects capital expenditures of $638.4 million in 2004 compared with the 2004 budgeted amount of $738 million. The revised 2004 projection includes $355.1 by CL&P, $148.2 million by PSNH, $38.4 million by WMECO, $62.4 million by Yankee Gas, and $34.3 million by other NU subsidiaries. The lower level of capital spending compared to the budget was

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primarily related to delays in approvals of certain major transmission projects as a result of an appeal of a Connecticut Siting Council (CSC) decision and other legal and regulatory delays.

Utility Group: At September 30, 2004, the Utility Group had no borrowings outstanding on its $300 million revolving credit line. This revolving credit line is scheduled to mature on November 8, 2004 and will be replaced on that date by a $400 million, five-year facility. Under this new credit line, CL&P will be able to borrow up to $200 million and PSNH, WMECO, and Yankee Gas will be able to borrow up to $100 million, each on a short-term basis.

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, 2004, CL&P had sold accounts receivable totaling $40 million to that financial institution. For more information regarding the sale of receivables, see Note 1G, Summary of Significant Accounting Policies - Sale of Customer Receivables to the condensed consolidated financial statements.

On September 17, 2004, CL&P issued $150 million of 10-year first mortgage bonds at a fixed interest rate of 4.8 percent and also issued $130 million of 30-year first mortgage bonds at a fixed interest rate of 5.75 percent. CL&P used the proceeds from these issuances to repay short-term debt.

As part of the approved SMD settlement agreement, CL&P paid $83 million to its suppliers on July 8, 2004. Under the settlement agreement, CL&P also agreed to refund $75 million to its customers. The $83 million supplier payment was made from an escrow fund that was established during 2003 as these costs were being collected from customers. Of the combined payment and refund amount totaling $158 million, $31 million was not funded from the escrow account. CL&P began returning the $75 million to customers over a four-month period on September 1, 2004. Additionally, the DPUC ordered a refund of $88.5 million in CTA/SBC overcollections over a seven-month period beginning with October 2004 consumption. The combination of the SMD and CTA/SBC refunds, when combined with CL&P s proposed capital expenditures, will negatively impact CL&P s liquidity. CL&P is also refunding GSC overrecoveries of $120 million over a four-year period beginning in 2004. However, CL&P expects no difficulty in meeting these additional cash requirements.

On July 22, 2004, PSNH issued $50 million of 10-year first mortgage bonds at a fixed interest rate of 5.25 percent. Proceeds were used to repay short-term debt and fund PSNH s capital expenditure program. In October 2004, PSNH received sufficient approvals to begin the construction related to the conversion of one of the coal-fired units at Schiller Station to burn wood. The NHPUC has approved the project but the NHPUC s approval is subject to an appeal to the New Hampshire Supreme Court. This project is expected to cost $75 million.

On September 23, 2004, WMECO issued $50 million of 30-year senior unsecured notes at a fixed interest rate of 5.9 percent. Proceeds were used to finance a trust fund which will be used to meet WMECO s prior spent nuclear fuel liability.

Yankee Gas plans to issue up to $50 million in 15-year first mortgage bonds in the fourth quarter of 2004, pursuant to existing DPUC approvals. The proceeds will be used primarily to repay short-term debt, approximately $35 million of which was incurred to redeem two series of high coupon rate first mortgage bonds in the fourth quarter of 2004. On September 3, 2004, the DPUC approved the application by Yankee Gas to construct a LNG storage facility with an estimated cost of approximately $100 million that is capable of storing the equivalent of 1.2 billion cubic feet of natural gas.

NU Enterprises: At September 30, 2004, NU Enterprises had $113.6 million in letters of credit (LOCs) outstanding on NU parent s $350 million revolving credit line. This revolving credit line is scheduled to mature on November 8, 2004 and will be replaced on that date by a $500 million five-year facility under which borrowings will be made on a short-term basis. NU is seeking to increase its short-term borrowing authorization from the Securities and Exchange Commission (SEC) to $500 million from $450 million. A total of $350 million of the $500 million under the credit line can be in the form of LOCs which can be used to provide support for Select Energy s activities.

NU Enterprises liquidity is significantly impacted by both the amount of collateral from other counterparties it receives and the amount of collateral it is required to deposit with counterparties.

On September 17, 2004, Moody s Investors Service lowered NGC s bond rating to Baa3 from Baa2 and changed the outlook to stable. The change is not expected to have any negative impact on NGC.

SESI borrowed a net total of $8.1 million during 2004 to finance the implementation of energy saving improvements at customer facilities. Cash to repay these borrowings is funded by SESI s energy savings contracts. No additional non-contract related borrowings were made in the third quarter of 2004.

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Nuclear Decommissioning and Plant Closure Costs

NU has significant decommissioning and plant closure cost obligations to the companies that own the Yankee Atomic (YA), Connecticut Yankee (CY) and Maine Yankee (MY) nuclear power plants (collectively, 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 CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. YA has received FERC approval to collect all presently estimated decommissioning costs. MY and various other parties filed a settlement agreement with the FERC, which provides for the collection of approximately $27 million annually through October 31, 2008 for all presently estimated decommissioning and long-term spent fuel storage costs. The MY settlement was approved by the FERC on September 16, 2004.

CY s estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised estimate reflects the fact that CY is now self-performing all work to complete the decommissioning of the plant due to the termination of the decommissioning contract with Bechtel Power Corporation (Bechtel) in July 2003, due to the increases in the projected costs of spent fuel storage, and increased security and liability and property insurance costs. NU s share of CY s increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CY filed with the FERC for recovery of these increased costs. In the filing, CY sought 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 beginning on February 1, 2005, subject to refund, and scheduled hearings for May 2005. In total, NU s estimated remaining decommissioning and plant closure obligation for CY is $310.2 million at September 30, 2004.

On June 10, 2004, the DPUC and OCC filed a petition seeking declaratory order that CY 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. On August 30, 2004, the FERC denied this petition. On September 29, 2004, the DPUC and OCC asked the FERC to reconsider the petition. On October 29, 2004, the FERC issued an order granting further consideration regarding the DPUC s and OCC s petition for reconsideration. No hearing date has been established.

CY is currently in litigation with Bechtel over the termination of its decommissioning contract. On June 13, 2003, CY gave notice of the termination of its contract with Bechtel for the decommissioning of its nuclear power plant. CY terminated the contract due to Bechtel s history of incomplete and untimely performance and refusal to perform the remaining decommissioning work. Bechtel has departed the site, and the decommissioning responsibility has been transitioned to CY, which has recommenced the decommissioning process.

On June 23, 2003, Bechtel filed a complaint against CY asserting a number of claims and seeking a variety of remedies, including monetary and punitive damages and rescission of the contract. Bechtel has since amended its complaint to add claims for wrongful termination. On August 22, 2003, CY filed its answer and counterclaims, including counts for breach of contract, negligent misrepresentation and breach of duty of good faith and fair dealing. Discovery is currently underway, and a trial has been scheduled for May 2006.

On July 20, 2004, the Connecticut Superior Court (the Court) allowed the DPUC to intervene in the prejudgment remedy (PJR) proceeding filed in June 2004 for the limited purpose of objecting to Bechtel s requested garnishment of the decommissioning trust and related payments. On October 27, 2004, Bechtel and CY entered into a stipulation under which Bechtel relinquished its right to seek garnishment of the decommissioning trust and related payments in return for the potential attachment of CY s real property in Connecticut with a book value of $7.9 million and the escrowing of $41.7 million the sponsors are scheduled to pay to CY through June 30, 2007. This stipulation is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. CY intends to contest the attachability of such assets.

NU cannot at this time predict the timing or outcome of the FERC proceeding required for the collection of the increased decommissioning costs. Management believes that the costs have been prudently incurred and will ultimately be recovered from the customers of CL&P, PSNH and WMECO. However, there is a risk that some portion of these increased costs may not be recovered, or will have to be refunded if recovered, as a result of the FERC proceedings. NU also cannot predict the timing and outcome of the litigation with Bechtel or its impact on NU. For additional current information regarding these issues and litigation with Bechtel, see Part II, Item 1, Legal Proceedings, in this report on Form 10-Q.

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The Yankee Companies are seeking recovery of damages from the United States Department of Energy (DOE) for the cost of storing spent nuclear fuel that the DOE has failed to remove. The DOE trial ended on August 30, 2004, and a verdict has not yet been reached. The related claim for damages from the DOE incurred through 2010 is approximately $500 million. The current rates of the Yankee Companies do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

Utility Group Business Development and Capital Expenditures

Connecticut - CL&P: On August 19, 2004 a Connecticut Superior Court judge dismissed an appeal by the City of Norwalk concerning construction of a 345,000 volt transmission project from Bethel, Connecticut to Norwalk, Connecticut. Based upon a recently completed estimate, the project is currently projected to cost between $300 million and $350 million, depending upon resolution of technical and siting issues. The project is expected to help alleviate identified reliability issues in southwest Connecticut and to help reduce congestion costs for all of Connecticut. This current cost estimate has increased from a previous estimate of $200 million due to a number of factors, including higher bids, especially for underground construction in southwest Connecticut, and additional requirements that were added during the extensive permitting and technical design process. While work on the related substations has begun, work on the transmission lines has not yet begun and is pending final reviews involving the CSC, the New England Independent System Operator (ISO-NE), and the Connecticut Department of Transportation. Management estimates a project completion date of December 2006, which is one year later than the previous estimate due to the Norwalk court appeal. At September 30, 2004, CL&P has capitalized $56.6 million associated with this project.

On October 9, 2003, CL&P and United Illuminating (UI) filed for approval of a separate 345,000 volt transmission line from Norwalk, Connecticut to Middletown, Connecticut. The CSC has requested, and CL&P and UI have granted, a six-month extension of the date for final decision to April 2005. Construction is expected to commence shortly after the final route and configuration are determined by CSC. Some of the alternatives being considered by CL&P and evaluated by ISO-NE and CSC are significantly more costly than CL&P s previous estimate of $620 million for the total project. For forecasting purposes, CL&P is using an estimated total project cost of $700 million with a 2009 in service date, both of which recognize the complexity of the issues surrounding the siting and construction of the project, as well as the potential for court appeals of the CSC decision. The current estimated construction cost of this project continues to be evaluated as the project scope and portions of the transmission line to be built overhead and underground are under review. CL&P will jointly site this project with UI, and CL&P will own 80 percent of the project. At September 30, 2004, CL&P has capitalized $15.8 million related to this project.

In September 2002, the CSC approved a plan to replace an undersea electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York. This project is estimated to cost in the range of $100 million, and CL&P and the Long Island Power Authority (LIPA) will each own approximately 50 percent of the line. CL&P has not yet signed a contract with a vendor to complete this work; therefore, the cost estimate could increase. The project has received CSC approval but still requires federal and New York state approvals. On October 1, 2004, consistent with a comprehensive settlement agreement reached on June 24, 2004, CL&P and LIPA jointly filed an implementation plan for the cable replacement with the Connecticut Department of Environmental Protection. Pending final approval, construction activities are scheduled to begin in the fall of 2006. Management expects the cable to be in service by the middle of 2008. At September 30, 2004, CL&P has capitalized $6.3 million related to this project.

In May 2004, CL&P applied to the CSC to construct two 115,000-volt underground transmission lines between Norwalk, Connecticut and Stamford, Connecticut. The project is expected to cost approximately $120 million and will help meet the growing electric demands in the area. Management expects the lines to be in service by 2008. At September 30, 2004, CL&P has capitalized $2.5 million related to this project.

In the first nine months of 2004, NU placed in service $85 million of electric transmission projects. These projects included CL&P s $37 million upgrade of a transmission substation in Stamford, Connecticut that will allow more than 100 additional MW to be imported into southwest Connecticut.

Connecticut - Yankee Gas: On September 3, 2004, the DPUC approved the application by Yankee Gas to construct a LNG storage facility in Waterbury, Connecticut, at an expected cost of approximately $100 million, that is capable of storing the equivalent of 1.2 billion cubic feet of natural gas. On October 18, 2004, Yankee Gas signed a contract with a vendor that will build the facility, which will be filled through both liquification of natural gas on-site and the transportation of LNG from off-site locations. Yankee Gas anticipates beginning construction late in 2004 and for the facility to become operational in late 2007 in time for the 2007/2008 heating season. At September 30, 2004, Yankee Gas has capitalized $5.4 million related to this project.

On November 1, 2004, Yankee Gas placed in service a new nine-mile gas line to connect its system in southeast Connecticut to the New England Gas Company (NEGASCO) system in Rhode Island. The construction project and a 20-year contract between Yankee Gas and NEGASCO were previously approved by the DPUC and the FERC. The NEGASCO project will provide Yankee Gas with additional revenue, improve service reliability in the Stonington, Connecticut area, and expand natural gas delivery into additional areas of southeastern Connecticut.

New Hampshire: In October 2004, PSNH received sufficient approvals to begin the construction related to the conversion of one of three 50 megawatt units at the coal-fired Schiller Station to burn wood (Northern Wood Project). The $75 million Northern Wood Project is expected to be completed by late 2006. The NHPUC s approval of the project is subject to an appeal to the New Hampshire Supreme Court brought by some of New Hampshire s existing wood-fired generating plant owners. Management does not believe that the appeal will negatively affect PSNH s ability to complete the Northern Wood Project.

For further information regarding rate matters associated with business development and capital expenditures, see Regulatory Issues and Rate Matters, in this Management s Discussion and Analysis.

Regional Transmission Organization

On October 31, 2003, the ISO-NE, along with NU and six other New England transmission owning companies, filed a proposal with the FERC to create an RTO for New England. On March 24, 2004, the FERC issued an order conditionally accepting the New England RTO proposal. The RTO is intended to strengthen the independent and efficient management of the region s power system while ensuring that customers in New England continue to have highly reliable service and also realize the benefits of a competitive wholesale energy market.

In a separate filing made on November 4, 2003, NU along with six other New England transmission owners requested, consistent with the FERC s pricing policy for RTOs and Order-2000-compliant independent system operators, that the FERC approve a single ROE for regional and local rates that would consist of a proposed 12.8 percent base ROE as well as incentive adders of 0.5 percent for joining a RTO and 1.0 percent for constructing new transmission facilities approved by the RTO.

In its March 24, 2004 order, the FERC accepted the proposal for the 0.5 percent incentive adder, but set for hearing the issues of the appropriate base ROE and the clarification as to which facilities the 1.0 percent incentive adder applies.

On October 29, 2004, NU along with the other New England transmission owners, filed rebuttal testimony with the FERC in preparation for December 2004 ROE hearings. The revised testimony, among other items, updated the required FERC discounted cash flow methodology calculations used to support the requested base ROE. This update to the calculations produced an 11.1 percent base ROE, which is 1.7 percent lower than the ROE originally proposed in November 2003 of 12.8 percent. The reduction in the ROE is due to changes in some of the inputs used in the discounted cash flow analysis. The incentive adders would still apply to the revised base ROE.

On November 3, 2004, the FERC issued an order that 1) determined that the New England transmission owners methodology used to calculate the proposed ROE is appropriate, 2) provided guidance related to the incentive adders and 3) approved certain compliance items that were required by the FERC s March 24, 2004 order.

The order approved the methodology that had been proposed by the transmission owners for calculating the base ROE, which is based on the use of the mid-point of a proxy group of companies. The FERC found in its order that the proxy group proposed by the transmission owners was appropriate. The actual base ROE will be determined utilizing this methodology following the hearings, which are scheduled to commence in December 2004. Management cannot at this time predict the ultimate ROE that will be determined following the hearings, and cannot predict whether the hearings regarding the ROE will be contentious.

The order also clarified the application of the 0.5 percent incentive adder for joining a RTO and reaffirmed the appropriateness of the 1.0 percent incentive adder for new investments. However, still unresolved is the type of investments to which the FERC believes that the 1.0 percent incentive adder should apply.

A final ruling regarding these issues is expected in the second quarter of 2005.

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Utility Group Regulatory Issues and Rate Matters

Transmission: On August 26, 2003, the transmission segment of NU s regulated companies filed a transmission rate case at the FERC. In the filing, the companies requested implementation of a formula rate that would allow recovery of increasing transmission expenditures on a timelier basis and that the changes, including a $23.7 million annual rate increase through 2004, take effect on October 27, 2003. The companies requested that the FERC maintain their existing 11.75 percent ROE until a ROE for the New England RTO is established by the FERC. On October 22, 2003, the FERC accepted this filing implementing the proposed rates subject to refund effective on October 28, 2003 and set several issues for hearing.

On June 14, 2004, the transmission segment of NU s regulated companies reached a settlement agreement with the parties to its rate case which allows NU to implement formula-based rates as proposed, with an allowed ROE of 11.0 percent. This ROE will be superceded by the ROE determined as part of the ongoing RTO proceedings. On September 15, 2004, the FERC approved the settlement agreement. The impact of the change in ROE from 11.75 percent to 11.0 percent was recognized in the second quarter and reduced earnings by $1.1 million.

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 the New England Regional Network Service (RNS) tariff and NU s Local Network Service (LNS) tariff. The RNS tariff, which is administered by ISO-NE, recovers the revenue requirements associated with transmission facilities that are deemed by the FERC to be regional facilities. This regional rate is reset on June 1st of each year. The LNS tariff provides for the recovery of NU s total transmission revenue requirements, net of revenues received from other sources, including those revenues received under RNS rates. NU s LNS tariff is also reset on June 1st of each year to coincide with the change in RNS rates. Additionally, NU s LNS tariff provides for a true-up to actual costs which ensures that NU recovers its total transmission revenue requirements, including the allowed ROE. Through September 30, 2004, this true-up has resulted in the recognition of a $4 million regulatory liability.

A significant portion of NU s transmission businesses revenue is from charges to NU s distribution businesses. These distribution businesses recover these charges through rates charged to their retail customers. WMECO has a rate tracking mechanism to track transmission costs charged in distribution rates to the actual amount of transmission charges incurred. The 2004 rates set in the CL&P distribution rate case contained a level of transmission revenue sufficient to recover CL&P s anticipated 2004 transmission costs. CL&P continues to evaluate whether or not it will seek a new retail transmission rate in 2005. The June 1, 2005 PSNH rate increase includes revenues to recover expected transmission costs. Neither CL&P nor PSNH have transmission tracking mechanisms.

Connecticut - CL&P:

Public Act No. 03-135 and Rate Proceedings: On June 25, 2003, the Governor of Connecticut signed into law Public Act No. 03-135 (the Act) which amended Connecticut s 1998 electric utility industry legislation. The Act required CL&P to file a four-year transmission and distribution plan with the DPUC. On December 17, 2003, the DPUC issued its final decision in the rate case.

CL&P filed a petition for reconsideration of certain items in the final decision on December 31, 2003. Other parties also filed petitions for reconsideration. The DPUC issued a final decision on the petitions on August 4, 2004. The final decision allows CL&P to recover an additional $32 million beginning August 1, 2004. The DPUC also authorized using existing CTA overrecoveries in lieu of an increase in rates to recover approximately $24 million, which is the net present value of the $32 million.

The final decision had a third quarter positive pre-tax impact of $10.2 million (approximately $6 million after-tax) on CL&P. The remaining amount will be amortized over four years as an increase to revenues as the related costs to be recovered are incurred. The DPUC s conclusion on streetlighting refund periods and methodologies was also included in the final decision, and management has determined that the streetlighting refund period and methodology included in the final decision did not have an impact on CL&P s net income or financial position at September 30, 2004.

Under the Act, CL&P is allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (kWh) from customers who purchase transitional standard offer service (TSO). That fee can increase to 0.75 mills if CL&P beats certain regional benchmarks. The fixed portion of the procurement fee amounted to approximately $9 million for the nine months ended September 30, 2004, and is expected to total approximately $12 million (approximately $7 million after-tax) for 2004. CL&P submitted to the DPUC its proposed methodology to calculate the variable portion (incentive portion) of the procurement fee. A decision is expected in the first quarter of 2005. The variable portion of the procurement fee has not been recorded in 2004 and could total approximately $6 million if CL&P s proposed methodology is approved by the DPUC.

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

On April 1, 2004, CL&P filed its 2003 CTA and SBC reconciliation with the DPUC, which compares CTA and SBC revenues to revenue requirements. A final decision in the 2003 CTA and SBC docket was issued on August 4, 2004 and ordered a refund to customers of $88.5 million over a seven-month period beginning with October 2004 consumption.

The DPUC also directed CL&P to impute revenues of $2.7 million during 2004 payable to customers associated with a previously renegotiated IPP contract. On September 15, 2004, CL&P filed an appeal and a motion for partial stay with the Connecticut Superior Court challenging the DPUC s August 4, 2004 decision regarding this contract. The motion for partial stay was granted. On October 15, 2004, CL&P entered into a settlement agreement involving the counterparties to this contract and various other parties. If approved by the DPUC and by the bankruptcy court of one of the counterparties, the DPUC will rescind the imputed revenues order and CL&P would withdraw its appeal. CL&P is awaiting approvals of the settlement agreement.

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P s request, and on October 24, 2003, CL&P appealed the DPUC s final decision to the Connecticut Superior Court. The appeal has been fully briefed and is in the argument phase, and a decision from the Connecticut Superior Court could be rendered by the end of 2004. If CL&P s request is granted through these court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

Impacts of Standard Market Design: On March 1, 2003, ISO-NE implemented SMD. As part of SMD, LMP is utilized to assign value and causation to transmission congestion and line losses. Transmission congestion costs represent the additional costs incurred due to the need to run uneconomic generating units in certain areas that have transmission constraints, which prevent these areas from obtaining alternative lower-cost generation. Line losses represent losses of electricity as it is sent over transmission lines.

CL&P was billed $186 million of incremental LMP costs in 2003 by its standard offer service suppliers, including affiliate Select Energy, or by ISO-NE and collected $158 million from its customers. CL&P and its suppliers disputed the responsibility for the $186 million of incremental LMP costs incurred. An agreement was reached settling the dispute among all the parties involved and was filed with the FERC on March 3, 2004. NU recorded a pre-tax loss in 2003 of approximately $60 million (approximately $37 million after-tax) related to this settlement agreement. The settlement agreement was approved by the FERC on June 28, 2004.

On July 8, 2004, CL&P paid the standard offer service suppliers $83 million as part of the approved settlement agreement. On August 25, 2004, the DPUC approved a joint proposal for refunding the remaining $75 million to customers. The approved refund was included in customer bills beginning with September 2004 billings and will continue through December 2004 billings. The refund will total $83.5 million, consisting of the remaining $75 million of SMD amounts and an additional $8.5 million associated with previous replacement power costs collected from customers but later recouped from a supplier.

Application for Issuance of Long-Term Debt: On September 9, 2004, CL&P filed an application with the DPUC requesting approval to issue long-term debt in the amount of $600 million during the period February 1, 2005 to December 31, 2007. Additionally, CL&P is requesting approval to enter into hedging transactions, from time to time ending on December 31, 2007, in connection with any prospective or outstanding long-term debt in order to reduce the interest rate risk associated with the debt or debt issuances. The DPUC has not yet issued a schedule for review of this application.

Connecticut - Yankee Gas:

Rate Case Filing: On July 2, 2004, Yankee Gas filed a rate case with the DPUC to increase retail rates by $26.5 million, or 7.2 percent, effective January 1, 2005. Yankee Gas also requested an authorized ROE of 10.75 percent in the rate case filing. The requested increase in rates results from increased costs of distribution delivery services such as pension and healthcare, as well as additional investments needed to maintain a safe and reliable gas distribution system.

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On October 14, 2004, Yankee Gas filed a settlement agreement with the DPUC. Parties to the agreement included the OCC and the Prosecutorial Division of the DPUC. The settlement agreement increases customer rates by $14 million annually, allows an ROE of 9.9 percent and reduces Yankee Gas annual expense for plant taken out of service by approximately $5 million. As part of the settlement agreement, Yankee Gas has generally agreed not to file a new rate increase application prior to the earlier of the in-service date of its new LNG facility or July 1, 2007. The DPUC has suspended the rate case hearing schedule and held a hearing on October 28, 2004 to review the settlement agreement. A decision is expected during the fourth quarter of 2004.

New Hampshire:

Delivery Rate Case: PSNH s delivery rates were fixed, effective May 1, 2001, by the Agreement to Settle PSNH Restructuring (Restructuring Settlement) until February 1, 2004. Consistent with the requirements of the Restructuring Settlement and state law, PSNH filed a delivery service rate case and tariffs with the NHPUC on December 29, 2003 to increase electricity delivery rates by approximately $21 million, or 2.6 percent, effective February 1, 2004.

On July 14, 2004, PSNH filed with the NHPUC a revenue requirements settlement agreement among several parties, including the NHPUC staff and the Office of Consumer Advocate (OCA). The terms of the proposed settlement agreement allowed for increases in PSNH s delivery rates totaling $3.5 million annually, effective prospectively on October 1, 2004, and an incremental $10 million annual increase effective prospectively on June 1, 2005, for a total rate increase of $13.5 million. On July 29, 2004, PSNH filed with the NHPUC a rate design settlement agreement among several parties, including the NHPUC staff. These proposed revenue requirements and rate design settlement agreements together resolve all delivery service rate case issues. On September 2, 2004, the NHPUC issued an order approving both settlement agreements, and new delivery service rates went into effect on October 1, 2004.

Transition Energy Service: In accordance with the Restructuring Settlement and state law, PSNH files for updated transition energy service (TS) rates annually. Presently, TS rates for all customers may change annually effective February 1st. The TS rate recovers PSNH s generation and purchased power costs, including a return on PSNH s generation investment. PSNH defers any difference between its TS revenues and the actual costs incurred.

On September 24, 2004, PSNH filed a petition with the NHPUC requesting a change in the TS rate for the period February 1, 2005 through January 31, 2006. In its filing, PSNH did not request a specific TS rate; rather, given the current price volatility in the energy markets, PSNH requested that the NHPUC review and approve its underlying operational data within the September 24, 2004 filing. In December 2004, PSNH expects to petition for a specific TS rate based on updated market information. Management expects the NHPUC to issue an order prior to February 1, 2005.

SCRC Reconciliation Filing: The stranded cost recovery charge (SCRC) allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the NHPUC a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and TS revenues billed with TS costs. The NHPUC reviews the filing, including a prudence review of PSNH s generation operations. The cumulative deferral of SCRC revenues in excess of costs was $200.6 million at September 30, 2004. This cumulative deferral will decrease the amount of non-securitized stranded costs that will have to be recovered from PSNH s customers in the future from $422.6 million to $222 million.

The 2003 SCRC reconciliation filing was filed with the NHPUC on April 30, 2004, and a proposed stipulation and settlement agreement between PSNH, the OCA and NHPUC staff was filed with the NHPUC on October 4, 2004. Under the terms of the settlement agreement, no costs related to the recovery of stranded costs or the cost of providing TS were disallowed, and the NHPUC staff agreed to accept the 2003 SCRC filing without change. On October 29, 2004, the NHPUC issued an order accepting the settlement agreement as filed.

Estimated unbilled revenues are not included in the reconciliation of billed revenues to incurred costs through rate mechanisms for the SCRC and the TS. At September 30, 2004, the unbilled balance related to SCRC and TS was $11.7 million and $16.7 million, respectively. The level of the TS rate will vary from time to time and will continue until it is replaced with Default Energy Service, or some equivalent, which will then continue indefinitely. The SCRC rate is expected to begin decreasing in late 2006. Management will seek from regulators a determination as to the ultimate inclusion of any of this unbilled revenue into billed rates.

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Massachusetts:

*Transition Cost Reconciliation:*On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy. This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The timing of a final decision is uncertain, but management does not expect the outcome of this docket to have a material adverse impact on WMECO s net income or financial position.

NU Enterprises

Business Segments: NU Enterprises aligns its businesses into two business segments, the merchant energy business segment and the energy services business segment. The merchant energy business segment includes Select Energy s wholesale and retail marketing businesses. Also included in this segment are 1,440 MW of generation assets, including 1,293 MW of pumped storage and hydroelectric generation assets at NGC and 147 MW of coal-fired generation assets at HWP. The wholesale business primarily services firm requirements sales to local distribution companies and bilateral sales to other counterparties. To serve these customers, Select Energy relies on its own generation and inventory of energy products procured in the market.

The energy services business segment includes the operations of SESI, NGS, and Woods Network. SESI performs energy management services for large commercial customers, institutional facilities and the United States government and energy-related construction services. NGS operates and maintains NGC s and HWP s generation assets and provides third-party electrical services. Woods Network is a network design, products and services company.

Outlook: The energy services business segment expected to earn in the range of between $1 million and $2 million.

Intercompany Transactions: CL&P s standard offer purchases from Select Energy represented $134.8 million for the three months ended September 30, 2004, compared with $184.9 million during the same period in 2003. Other energy purchases between CL&P and Select Energy totaled $25.7 million for the three months ended September 30, 2004 and $32.2 million during the same period in 2003. Additionally, WMECO s purchases from Select Energy represented $28 million for the three months ended September 30, 2004, compared with $42.1 million during the same period in 2003.

CL&P s standard offer purchases from Select Energy represented $391.5 million for the first nine months of 2004, compared with $464.8 million during the same period in 2003. Other energy purchases between CL&P and Select Energy totaled $83.4 million for the first nine months of 2004 and $101.4 million during the same period in 2003. Additionally, WMECO s purchases from Select Energy represented $81.5 million for the first nine months of 2004, compared with $110.3 million during the same period in 2003. These amounts are eliminated in consolidation.

NU Enterprises Market and Other Risks

Overview: For further information on risk management activities, see Competitive Energy Subsidiaries Market and Other Risks in NU s combined report on Form 10-K.

Risk management within Select Energy is organized to address the market, credit and operational exposures arising from the merchant energy business segment, which include: wholesale marketing activities (including limited energy trading for market and price discovery purposes as well as asset optimization) and retail marketing activities. The framework for managing these risks is set forth in NU s risk management policies and procedures, which are reviewed by the NU Board of Trustees on an as needed basis.

A significant portion of Select Energy s merchant energy marketing activities is providing electricity to full requirements customers, which are primarily regulated local distribution companies (LDCs) and commercial and industrial retail customers. Under the terms of full requirements contracts, Select Energy is required to provide a percentage of the LDC s electricity requirements at all times. The volumes sold under these contracts vary based on the usage of the LDC s retail electric customers, and usage is dependent upon factors outside of Select Energy s control, such as the weather. The varying sales volumes could be different than the supply volumes that Select Energy expected to utilize, either from generation or from electricity purchase contracts, to serve the full requirements contracts. Differences between actual sales volumes and supply volumes can require Select Energy to purchase additional electricity or sell excess electricity, both of which are subject to market conditions such as weather, plant availability, transmission congestion, and potentially volatile price fluctuations that can impact prices and, in turn, Select Energy s margins.

The pricing terms of full requirement contracts and of supply contracts can affect the timing of Select Energy s margins. Many full requirements contracts have higher prices in certain months, while certain supply contracts have one price for the

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entire contract term. Accordingly, Select Energy s margins will tend to be higher in the months when the full requirements contract price is high and lower or could be negative when the full requirements contract price is lower.

Energy Sourcing Activities: In June 2004, Select Energy began purchasing fixed-price electricity and some electricity with prices indexed to gas for 2005 and 2006 in anticipation of winning full requirements contract sales and sales to load-serving entities. Purchasing electricity in advance of winning contracts exposes Select Energy to the risk of electricity price decreases before the full requirement quantities are contracted and before contract prices are known.

To mitigate the risk of electricity price decreases on the fixed-price electricity that was purchased, Select Energy in June 2004 began selling contracts for wholesale natural gas delivery (basis contracts) and natural gas futures and swaps contracts for 2005 and 2006. Select Energy expected that the result of this risk mitigation strategy would be that decreases in the value of the fixed-price electricity purchase contracts would be offset in part by increases in the value of the gas contracts, and vice versa. Select Energy intends to purchase natural gas when quantities and prices of electricity are secured by full requirements contracts or sales contracts with load-serving entities. Natural gas was sold in this risk mitigation strategy due to the high liquidity of the natural gas market compared to the low liquidity of electricity in the Northeast.

The electricity contracts are accounted for on the accrual basis, which will result in earnings recognition when the electricity is delivered in 2005 and 2006. These electricity purchase contracts are expected to be used to meet electricity sales contract requirements, which are a key component of Select Energy s business. Select Energy believes that this electricity will be delivered to its customers.

The use of fair value accounting for the natural gas basis and futures and swaps contracts has exposed and will continue to expose Select Energy s and NU s earnings to future changes in natural gas prices, which could be significant. This has and can reasonably be expected to create uncertainty regarding Select Energy s and NU s earnings and earnings trends. The electricity contracts are not expected to be accounted for at fair value, and changes in the value of these contracts, which could be significant, will not impact earnings until the electricity is delivered.

The natural gas basis and futures and swaps contracts are included in non-trading derivative assets and liabilities in the table in Note 2, Derivative Instruments, to the condensed consolidated financial statements.

Merchant Energy Marketing Activities: Select Energy manages its portfolio of wholesale and retail marketing contracts and assets to maximize value while maintaining an acceptable level of risk. There could be significant volatility in the electricity commodities markets that could affect merchant energy assets and contracts between now and when the electricity is delivered and the contracts are settled. Accordingly, there can be no assurances that Select Energy will realize the gross margin expected from its wholesale marketing portfolio.

Hedging and Other Non-Trading: For information on derivatives used for hedging purposes and non-trading derivatives, see Note 2, Derivative Instruments, to the condensed consolidated financial statements.

Wholesale Contracts Defined as Energy Trading : Energy trading transactions at Select Energy include financial transactions and physical delivery transactions for electricity, natural gas and oil in which Select Energy is attempting to profit from changes in market prices. Energy trading contracts are recorded at fair value, and changes in fair value affect net income.

At September 30, 2004, Select Energy had trading derivative assets of $94 million and trading derivative liabilities of $71 million, for a net positive position of $23 million for the entire trading portfolio. These amounts are combined with other derivatives and are included in derivative assets and derivative liabilities on the accompanying condensed consolidated balance sheets. The decrease in both derivative asset and liability amounts from June 30, 2004, relates primarily to contracts realized or otherwise settled during the period. Information regarding non-trading and other derivatives is included in Note 2, Derivative Instruments, to the condensed consolidated financial statements.

There can be no assurances that Select Energy will realize cash corresponding to the present positive net fair value of its trading positions. Numerous factors could either positively or negatively affect the realization of the net fair value amount in cash. These include the volatility of commodity prices, changes in market design or settlement mechanisms, the outcome of future transactions, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all trading positions to be marked-to-market at the end of each business day and segregating responsibilities between the individuals actually trading (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.

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The methods used to determine the fair value of energy trading contracts are identified and segregated in the table of fair value of contracts at September 30, 2004. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange futures 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. Currently, Select Energy has no contracts for which fair value is determined based on a model or other valuation method. Broker quotes for electricity at locations that Select Energy has entered into deals are available through the year 2006. Broker quotes for natural gas are available through 2013.

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. However, Select Energy has obtained corresponding purchase or sale contracts for substantially all of the trading contracts that have maturities in excess of one year. Because these contracts are sourced, changes in the value of these contracts due to fluctuations in commodity prices are not expected to affect Select Energy s earnings.

As of and for the nine months ended September 30, 2004, the sources of the fair value of trading contracts and the changes in fair value of these trading contracts are included in the following tables. Intercompany transactions are eliminated and not reflected in the amounts below.

(Millions of Dollars)	Fair Value of Trading Contracts at September 30, 2004			
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	$0.7	$0.2	$	$ 0.9
Prices provided by external sources	1.1	7.7	13.3	22.1
Totals	$1.8	$7.9	$13.3	$23.0

The fair value of energy trading contracts decreased $5.3 million from $28.3 million at June 30, 2004 to $23 million at September 30, 2004. The change in the fair value of the trading portfolio is primarily attributable to contracts realized or otherwise settled during the period. There were no changes in valuation techniques or assumptions in the third quarter of 2004.

	Total Portfolio Fair Value	
(Millions of Dollars)	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2004
Fair value of trading contracts outstanding at the beginning of the period	$28.3	$ 32.5
Contracts realized or otherwise settled during the period	(5.4)	(11.5)
Changes in fair value of contracts	0.1	2.0
Fair value of trading contracts outstanding at the end of the period	$23.0	$ 23.0

Changing Market: The breadth and depth of the market for energy marketing products in Select Energy s areas of business have been adversely affected by the withdrawal or financial weakening of a number of companies, particularly power marketers, who have historically done significant amounts of business with Select Energy. In general, the market for such products is shorter term in nature with less liquidity, market pricing information is less readily available and participants are sometimes unable to meet Select Energy s credit standards without providing cash or LOC support. Select Energy is being adversely affected by these factors, and there could be a continuing adverse impact on Select Energy s business lines due to its increasing reliance on business arrangements with a more limited number of counterparties, primarily power generators.

Changes are occurring in the administration of transmission systems in territories in which Select Energy does business. RTOs are being proposed and approved, and other changes in market design are occurring within transmission regions. As the market continues to evolve, there could be additional challenges or opportunities that management cannot determine at this time.

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 written 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, 2004, approximately 74 percent of Select Energy s counterparty credit exposure to wholesale and trading counterparties was cash collateralized or rated BBB- or better. Select Energy received $67.4 million and $46.5 million of counterparty deposits at September 30, 2004 and December 31, 2003, respectively. Select Energy used these amounts to fund current operations. For further information, see Note 1M, Counterparty Deposits, to the condensed consolidated financial statements.

Select Energy s Credit: A number of Select Energy s contracts require the posting of additional collateral in the form of cash or LOCs in the event NU s ratings were to decline and in increasing amounts dependent upon the severity of the decline. At NU s present investment grade ratings, Select Energy has not had to post any collateral based on credit downgrades. Were NU s unsecured ratings to decline two to three levels to sub-investment grade, Select Energy could, under its present contracts, be asked to provide approximately $384 million of collateral or LOCs to various unaffiliated counterparties and approximately $136 million to several independent system operators and unaffiliated local distribution companies, which management believes NU would currently be able to provide, subject to the SEC limits described below. NU s credit ratings outlooks are currently stable or negative, but management does not believe that at this time there is a significant risk of a ratings downgrade to sub-investment grade levels.

On June 30, 2004, the SEC issued an order allowing NU to significantly expand its financial support of NU Enterprises. The new order allows NU through June 30, 2007 to 1) increase its allowable investments in certain of its unregulated businesses, presently 15 percent of its consolidated capitalization as permitted by SEC regulation, by an additional $500 million, 2) increase the limit for its guarantees of all of its competitive affiliates from $500 million to $750 million, and 3) increase its allowable investments in exempt wholesale generators (EWGs) from $481 million to $1 billion. The order will permit NU to fully support the planned level of business activities of Select Energy and its other unregulated businesses. NU has no present plans to significantly expand its EWG portfolio. However, if an investment opportunity becomes available, NU will be able to pursue it within the new allowable EWG investment level.

For further information regarding Select Energy s activities and risks, see Note 2, Derivative Instruments, and Note 5, Comprehensive Income, to the condensed consolidated financial statements.

Critical Accounting Policies and Estimates Update

Derivative Accounting, the Election of Normal, and the Use of Hedge Accounting: Most of the contracts comprising Select Energy s wholesale and retail marketing activities are derivatives. The application of derivative accounting under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, is complex and requires management s judgment. Judgment is applied in determining the qualification for the election of the normal purchases and sale exception (and resulting accrual accounting), which includes the conclusions that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting would be terminated and fair value accounting would be applied.

Cash flow hedge contracts that are designated as hedges for contracts for which the company has elected the normal purchases and sales exception can continue to be accounted for as cash flow hedges only if the normal exception for the hedged contract continues to be appropriate. If the normal exception is terminated, then the hedge designation would be terminated at the same time and fair value accounting would be applied.

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, which 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 were filed in the fall of 2004 for the 2003 tax year. Management adjusted NU s tax reserves to reflect the difference in the actual 2003 tax return amounts being compared to the 2003 year end estimated tax expense. Recording these tax reserve adjustments resulted in a positive impact in the third

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quarter on NU s earnings of approximately $3.7 million, including a PSNH adjustment of a positive $5.4 million, a CL&P adjustment of a negative $3.2 million, a WMECO adjustment of a positive $0.6 million, and a NU Enterprises adjustment of a positive $1.8 million. Adjustments for other NU subsidiaries amounted to a negative $0.9 million. The process of truing up the income tax differences between the condensed consolidated financial statements and the income tax returns is an annual procedure.

Goodwill Impairment Testing: NU conducts annual goodwill impairment testing as of October 1st. Testing of current goodwill balances commenced in October of 2004.

Adjustments to the Impact of the Medicare Subsidy: On December 8, 2003, the President signed into law a bill that expanded Medicare, primarily by adding a prescription drug benefit and by adding a federal subsidy to qualifying plan sponsors of retiree health care benefit plans. Management believes that NU currently qualifies for the subsidy.

The actuarial gain resulting from the expansion of the Medicare program decreases the postretirement benefits other than pensions (PBOP) accumulated plan benefit obligation. Based on the most recent actuarial valuation as of January 1, 2004, the impact of the Medicare program has been revised from a $20 million decrease in the PBOP benefit obligation at December 31, 2003 to $27 million at September 30, 2004. The total $27 million decrease consists of $20 million as a direct result of the subsidy for certain non-capped retirees and $7 million related to changes in participation assumptions for capped retirees and future retirees as a result of the subsidy. The total $27 million decrease is currently being amortized as a reduction to PBOP expense over approximately 13 years. For the nine months ended September 30, 2004, this reduction in PBOP expense totaled approximately $2.8 million, including amortization of the actuarial gain of $1.5 million and a reduction in interest cost based on a lower PBOP benefit obligation of $1.3 million.

Utility Group Unbilled Revenues: Unbilled revenues represent an estimate of electricity or gas delivered to customers that has not been billed. Unbilled revenues are assets on the condensed consolidated balance sheet that become accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when changes in estimating methodology occur and under other circumstances.

The Utility Group estimates unbilled revenues monthly using the requirements method. The requirements method utilizes the total monthly volume of electricity or gas delivered to the system and applies a delivery efficiency (DE) factor to reduce the total monthly volume by an estimate of delivery losses in order to calculate total estimated monthly sales to customers. The total estimated monthly sales amount less the total monthly billed sales amount results in a monthly estimate of unbilled sales. Unbilled revenues are estimated by applying an average rate to the estimate of unbilled sales. The estimated DE factor can have a significant impact on estimated unbilled revenue amounts.

In accordance with management s policy of testing the estimate of unbilled revenues twice each year using the cycle method of estimating unbilled revenues, testing was performed in the second quarter of 2004. The cycle method uses the billed sales from each meter reading cycle and an estimate of unbilled days in each month based on the meter reading schedule. The cycle method is more accurate than the requirements method when used in a mostly weather-neutral month.

The cycle method testing resulted in adjustments to the estimate of unbilled revenues that had a net positive after-tax earnings impact of $1.5 million in the second quarter of 2004. There were positive after-tax impacts on CL&P, WMECO and Yankee Gas of $1.8 million, $0.9 million, and $0.5 million, respectively, while there was a negative after-tax impact on PSNH of $1.7 million.

Testing using the cycle method will be performed again in the fourth quarter of 2004, and any adjustment will be recorded in the fourth quarter of 2004.

Other Matters

Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 4, Commitments and Contingencies, to the condensed consolidated financial statements.

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The following are material updates to the table of contractual obligations and commercial commitments disclosed in NU s 2003 report on Form 10-K:

(Millions of Dollars)	2004	2005	2006	2007	2008	Thereafter
Contracted expenditures for construction of Yankee Gas LNG facility	$ 7.5	$ 30.6	$ 39.3	$ 3.4	$	$
Northern Wood Project	21.6	36.5	5.6			
FERC-approved billings from the Yankee Companies	40.8	92.5	74.4	68.6	60.9	113.5
	$69.9	$159.6	$119.3	$72.0	$60.9	$ 113.5

Certain other estimated construction expenditures totaling $19.2 million related to the Yankee Gas LNG facility and $11.3 million related to the Northern Wood Project are not included in the contracts signed to build these facilities and are not included in the table above. NU s other long-term contractual arrangements have not changed materially from the amounts reported at December 31, 2003.

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 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 uncerta 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, expiration or initiation of significant energy supply contracts, regulations or regulatory policy, levels of capital expenditures, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the 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.

Website: Additional financial information is available through NU s website at www.nu.com.

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RESULTS OF OPERATIONS - NU CONSOLIDATED

The following table provides the variances in income statement line items for the condensed consolidated statements of income for NU included in this report on Form 10-Q for the third quarter of 2004 and the first nine months of 2004:

	Income Statement Variances (Millions of Dollars) 2004 over/(under) 2003			
	Third Quarter	Percent	Nine Months	Percent
Operating Revenues:	$ 28	2%	$ 476	10%
Operating Expenses:				
Fuel, purchased and net interchange power	73	7	431	16
Other operation	41	18	126	19
Maintenance	8	17	12	8
Depreciation	6	12	16	11
Amortization	(14)	(24)	(40)	(28)
Amortization of rate reduction bonds	3	6	9	8
Taxes other than income taxes	2	4	10	6
Total operating expenses	119	8	564	14
Operating income	(91)	(72)	(88)	(22)
Interest expense, net			3	2
Other income, net	3	75	7	(a)
Income before income tax expense	(88)	(a)	(84)	(40)
Income tax expense	(36)	(a)	(36)	(47)
Preferred dividends of subsidiary				
Income before cumulative effect of accounting change	(52)	(a)	(48)	(36)
Cumulative effect of accounting change, net of tax benefit	5	100	5	100
Net Income	$ (47)	(a)%	$ (43)	(34)%

(a) Percent greater than 100.

Comparison of the Third Quarter of 2004 to the Third Quarter of 2003

Operating Revenues
Total revenues increased $28 million in the third quarter of 2004, compared with the same period in 2003, due to higher revenues from NU Enterprises ($78 million after intercompany eliminations), higher gas distribution revenues ($17 million) and higher regulated transmission revenues ($5 million after intercompany eliminations), partially offset by lower electric distribution revenues ($72 million).

NU Enterprises contribution to consolidated NU revenues increased primarily due to more of its revenues coming from companies that are not other subsidiaries of NU ($71 million), and due to higher revenues for the merchant energy segment resulting from higher gas prices and volumes ($10 million). Total NU Enterprises third quarter revenues before eliminations were flat in 2004 compared to 2003.

The electric distribution revenue decrease is primarily due to lower SMD revenue for CL&P ($91 million), lower sales volume for distribution revenues ($14 million) which includes the absence of the 2003 positive unbilled revenue estimate change, lower CL&P Energy Adjustment Clause (EAC) revenue as a result of the end of EAC billings in December 2003 ($12 million), lower revenues for CL&P and WMECO transition charges ($17 million), partially offset by increases in the standard offer, TS, and default service revenues for CL&P, PSNH and WMECO ($41 million) due mainly to rate increases and Federally Mandated Congestion Cost (FMCC) revenues for CL&P ($40 million). Electric retail kWh sales decreased by 4.9 percent in the third quarter of 2004 primarily due to the 2003 unbilled revenue estimate change. In addition, electric wholesale revenues decreased by $27 million primarily due to lower short-term transactions ($21 million) and the expiration of long-term contracts ($6 million).

The higher gas distribution revenues are primarily due to the absence of the 2003 negative adjustment to the estimate of unbilled revenues ($19 million).

Transmission revenues were higher due to the October 2003 implementation of the transmission rate case filed at the FERC.

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Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $73 million in the third quarter of 2004, primarily due to higher costs at NU Enterprises ($62 million after intercompany eliminations) and higher purchased power costs for the Utility Group ($11 million after intercompany eliminations). The NU Enterprises increase includes the negative $76 million related to the mark-to-market accounting for certain natural gas contracts. The increase for the Utility Group is primarily due to more of its standard offer service being provided by companies that are not other subsidiaries of NU ($71 million) as a result of the change in the amount of standard offer service provided by Select Energy, partially offset by the decrease in the CL&P fuel expense amortization resulting from the rate adjustment clauses ($62 million).

Other Operation

Other operation expenses increased $41 million in the third quarter of 2004, primarily due to higher competitive business expenses resulting from business growth ($19 million) and higher CL&P reliability must run costs ($22 million) and other power pool related expenses ($6 million), higher regulated business administrative and general expenses ($13 million) primarily due to higher pension costs and higher distribution expenses ($2 million), partially offset by lower C&LM spending ($13 million).

Maintenance

Maintenance expenses increased $8 million in the third quarter of 2004, primarily due to higher distribution maintenance expense ($3 million) and higher fossil production expense ($3 million).

Depreciation

Depreciation increased $6 million in the third quarter of 2004 due to higher Utility Group plant balances and higher depreciation rates at CL&P resulting from the distribution rate case decision effective in January 2004.

Amortization

Amortization decreased $14 million in the third quarter of 2004 primarily due to lower Utility Group recovery of stranded costs ($7 million) and a decrease in CL&P amortization expense resulting from the distribution rate case decision effective in January 2004 ($7 million).

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $3 million in the third quarter of 2004 due to the repayment of additional principal as compared to 2003.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $2 million in the third quarter of 2004 primarily due to higher local property taxes, higher payroll taxes and higher sales tax.

Other Income, Net
Other income, net increased $3 million in the third quarter of 2004 primarily due to the recognition beginning in 2004 of a CL&P procurement fee approved in the December 2003 TSO docket decision ($3 million).

Income Tax Expense
Income tax expense decreased $36 million in the third quarter of 2004 due to lower income before tax expense along with a lower effective tax rate due to adjustments to tax reserves as a result of the actual 2003 tax return amounts compared to the 2003 year end tax provision estimates.

Comparison of the First Nine Months of 2004 to the First Nine Months of 2003

Operating Revenues
Total revenues increased $476 million in the first nine months of 2004, compared with the same period in 2003, due to higher revenues from NU Enterprises ($377 million after intercompany eliminations), higher electric distribution revenues ($53 million), higher gas distribution revenues ($38 million) and higher regulated transmission revenues ($8 million after intercompany eliminations).

The NU Enterprises revenue increase is primarily due to higher revenues for the merchant energy segment resulting from higher electric prices ($146 million), higher gas volumes ($54 million) and higher gas prices ($25 million), partially offset by lower electric volumes ($7 million). The NU Enterprises contribution to consolidated NU revenues increased due to more of its revenues coming from companies that are not other subsidiaries of NU ($122 million).

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The electric distribution revenue increase is primarily due to increases in the standard offer, TS, and default service revenues for CL&P, PSNH and WMECO ($192 million) due mainly to rate increases, FMCC revenues for CL&P ($115 million) and higher CL&P retail transmission rates ($20 million), partially offset by lower SMD revenue for CL&P ($120 million), lower CL&P EAC revenue as a result of the end of EAC billings in December 2003 ($33 million) and lower revenues for CL&P and WMECO transition revenues ($34 million). In addition, electric wholesale revenues decreased by $74 million primarily due to lower short-term transactions ($56 million) and the expiration of long-term contracts ($18 million).

The higher gas distribution revenue is primarily due to the increased recovery of gas costs and the absence of the 2003 unbilled revenue estimate change ($28 million).

Transmission revenues were higher due to the October 2003 implementation of the transmission rate case filed at the FERC.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense increased $431 million in the first nine months of 2004, primarily due to higher wholesale costs at NU Enterprises ($258 million after intercompany eliminations) and higher purchased power costs for the Utility Group ($170 million after intercompany eliminations). The NU Enterprises increase includes the negative $74 million related to the mark-to-market accounting for certain natural gas contracts. The increase for the Utility Group is primarily due to more of its standard offer service being provided by companies that are not other subsidiaries of NU ($122 million) as a result of the change in the amount of standard offer service provided by Select Energy, an increase in the standard offer service requirements rates for CL&P ($66 million) and WMECO ($15 million), higher Yankee Gas expenses due to increased gas prices ($28 million), partially offset by the 2003 recovery of certain fuel costs ($33 million), lower wholesale purchases for CL&P ($17 million) and WMECO ($5 million), and lower expenses for PSNH due to lower regulated energy and capacity purchases ($7 million).

Other Operation
Other operation expenses increased $126 million in the first nine months of 2004, primarily due to higher competitive business expenses

resulting from business growth ($57 million), higher CL&P reliability must run costs ($42 million) and other power pool related expenses ($8 million), higher regulated business administrative and general expenses ($18 million) primarily due to higher pension costs, higher fossil production expense ($4 million), higher distribution expenses ($4 million), and higher nuclear related expenses as a result of the absence of the 2003 CL&P Millstone use of proceeds docket ($2 million), partially offset by lower C&LM spending ($11 million). That docket resulted in the recovery of certain other operation costs and maintenance costs that were expensed in periods prior to 2003. The recovery of these costs through the use of proceeds docket resulted in credits to these accounts in the first quarter of 2003.

Maintenance
Maintenance expenses increased $12 million in the first nine months of 2004, primarily due to higher distribution maintenance expense ($6 million) and the absence of the 2003 positive resolution of the CL&P Millstone use of proceeds docket ($5 million).

Depreciation
Depreciation increased $16 million in the first nine months of 2004 due to higher Utility Group plant balances and higher depreciation rates at CL&P resulting from the distribution rate case decision effective in January 2004.

Amortization
Amortization decreased $40 million in the first nine months of 2004 primarily due to lower Utility Group recovery of stranded costs and a decrease in amortization expense resulting from the implementation of the CL&P distribution rate case decision effective in January 2004 ($22 million).

Amortization of Rate Reduction Bonds
Amortization of rate reduction bonds increased $9 million in the first nine months of 2004 due to the repayment of additional principal as compared to 2003.

Taxes Other Than Income Taxes
Taxes other than income taxes increased $10 million in the first nine months of 2004 primarily due to higher Connecticut gross earnings tax as a result of an increase in revenues for NU Enterprises, CL&P and Yankee Gas, higher local property taxes, higher payroll taxes and higher sales tax.

Interest Expense, Net
Interest expense, net increased $3 million in the first nine months of 2004 primarily due to the issuance of $75 million of ten-year notes at Yankee Gas in January 2004.

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Other Income, Net
Other income, net increased $7 million in the first nine months of 2004 primarily due to the recognition beginning in 2004 of a CL&P procurement fee approved in the TSO docket decision ($9 million).

Income Tax Expense
Income tax expense decreased $36 million in the first nine months of 2004 due to lower income before tax expense along with a lower effective tax rate due to adjustments to tax reserves as a result of the actual 2003 tax return amounts compared to the 2003 year end tax provision estimates.

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ITEM 4. CONTROLS AND PROCEDURES (RESTATED)

NU, CL&P, PSNH, and WMECO (collectively, the companies) evaluated the design and operation of their disclosure controls and procedures at September 30, 2004 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 the companies principal executive officers and principal financial officer, as of the end of the period covered by this report on Form 10-Q/A. The principal executive officers and principal financial officer previously concluded, based on their review, that the companies disclosure controls and procedures were effective to ensure that information required to be disclosed by the companies in reports that they file under the Exchange Act (i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and (ii) is accumulated and communicated to management, including the principal executive officers and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

On January 26, 2005, subsequent to the September 30, 2004 disclosure control and procedures evaluation, it was determined that there was a material weakness in NU s internal controls over financial reporting. This weakness relates to the discovery, subsequent to the filing of the September 30, 2004 Form 10-Q, of an accounting error in which certain natural gas basis contracts at NU s subsidiary Select Energy were incorrectly accounted for on an accrual basis and certain natural gas futures and swaps contracts were incorrectly accounted for as cash flow hedges. This conclusion is based on the intent of these contracts to hedge electricity contracts, the uncertainty as to if the contracts will result in physical delivery, and the relationship of these contracts to the status of the wholesale natural gas business. The controls and procedures that should have prevented this error will be enhanced and include improved communications, derivative documentation, reporting relationships, and other items.

This error resulted in the restatement of NU s condensed consolidated financial statements as of and for the three and nine month periods ended September 30, 2004, and this Form 10-Q/A reflects the change from accrual and hedge accounting to fair value accounting for the contracts described above. Because of these restatements, NU s principal executive officer and principal financial officer, following consultation with and approval of the Audit Committee of the Board of Trustees, have now concluded that NU s disclosure controls and procedures were not effective as of September 30, 2004.

The principal executive officer and principal financial officer of CL&P, PSNH, and WMECO continue to believe that their disclosure controls and procedures were effective to ensure that information required to be disclosed by CL&P, PSNH, and WMECO in reports that they file under the Exchange Act i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and ii) is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There were no significant changes in the companies internal controls over financial reporting during the quarter ended September 30, 2004 that have materially affected, or are reasonably likely to materially affect the companies internal controls over financial reporting. Changes to address the material weakness described above were not yet implemented at September 30, 2004.

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PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Listing of Exhibits (NU)

Exhibit No.	Description

10.1	Letter Agreement relating to employment of Lawrence E. De Simone dated September 27, 2004*
31	Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 15, 2005
31.1	Certification of David R. McHale, Senior Vice President and Chief Financial Officer of Northeast Utilities, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 15, 2005
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 March 15, 2005

*Filed with original report on Form 10-Q.

(b) Reports on Form 8-K:

NU and PSNH filed current reports on Form 8-K dated July 14, 2004 disclosing:

The filing with the NHPUC of a settlement among several parties with regards to its delivery service rate case.

NU and CL&P filed current reports on Form 8-K dated August 19, 2004 disclosing:

The dismissal of the appeal by the City of Norwalk concerning the Bethel, Connecticut to Norwalk, Connecticut transmission project.

NU filed a current report on Form 8-K dated September 15, 2004 disclosing:

The announcement that John H. Forsgren, Vice Chairman, Executive Vice President and Chief Financial Officer, will retire effective January 1, 2005 and at that time, David R. McHale, NU Vice President and Treasurer, will be promoted to senior vice president and chief financial officer.

NU filed a current report on Form 8-K dated October 25, 2004 disclosing:

NU s financial results for the third quarter and nine months ended September 30, 2004.

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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: March 15, 2005

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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