CONNECTICUT LIGHT & POWER CO
Form 10-K
February 27, 2009

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2008

OR

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

For the transition period from ____________ to ____________

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

780 North Commercial Street
Manchester, New Hampshire 03101-1134
Telephone: (603) 669-4000

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

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Northeast Utilities	Common Shares, $5.00 par value	New York Stock Exchange, Inc.
Northeast Utilities	Common Share Purchase Rights	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
The Connecticut Light and Power Company	Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are outstanding:

$1.90	Series	of 1947
$2.00	Series	of 1947
$2.04	Series	of 1949
$2.20	Series	of 1949
3.90%	Series	of 1949
$2.06	Series E	of 1954
$2.09	Series F	of 1955
4.50%	Series	of 1956
4.96%	Series	of 1958
4.50%	Series	of 1963
5.28%	Series	of 1967
$3.24	Series G	of 1968
6.56%	Series	of 1968

Public Service Company of New Hampshire and Western Massachusetts Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

Yes	No
√	

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes	No
	√

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

Yes	No
√	

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
Northeast Utilities	√		
The Connecticut Light and Power Company			√

Public Service Company of New Hampshire	√
Western Massachusetts Electric Company	√

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

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

The aggregate market value of **Northeast Utilities'** Common Shares, $5.00 par value, held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of Northeast Utilities most recently completed second fiscal quarter (June 30, 2008) was **$3,970,521,694** based on a closing sales price of **$25.53** per share for the 155,523,764 common shares outstanding on June 30, 2008. **Northeast Utilities** holds all of the 6,035,205 shares, 301 shares, and 434,653 shares of the outstanding common stock of **The Connecticut Light and Power Company, Public Service Company of New Hampshire** and **Western Massachusetts Electric Company,** respectively.

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

Company - Class of Stock	Outstanding at January 31, 2009
Northeast Utilities Common shares, $5.00 par value	155,878,897 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
Public Service Company of New Hampshire Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company Common stock, $25.00 par value	434,653 shares

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated
Portions of the Northeast Utilities Proxy Statement expected to be dated April 1, 2009	Part III

GLOSSARY OF TERMS

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

COMPANIES

Boulos	E. S. Boulos Company
CL&P	The Connecticut Light and Power Company
CRC	CL&P Receivables Corporation
HWP	Holyoke Water Power Company
Mt. Tom	Mt. Tom generating plant
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company and subsidiaries
NU or the company	Northeast Utilities
NU Enterprises	NU Enterprises, Inc. is the parent company of Select Energy, Boulos, NGS, and SECI. For further information, see Note 17, "Segment Information," to the consolidated financial statements.
NUSCO	Northeast Utilities Service Company
NU parent and other companies	NU parent and other companies is comprised of NU parent, NUSCO, HWP (since January 1, 2007) and other subsidiaries, including The Rocky River Realty Company and The Quinnehtuk Company (both real estate subsidiaries), Mode 1 Communications, Inc. and the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, Yankee Energy Financial Services Company and NorConn Properties, Inc.).
PSNH	Public Service Company of New Hampshire
Regulated companies	NU's regulated companies, comprised of the electric distribution and transmission segments of CL&P, PSNH and WMECO, the generation segment of PSNH, and Yankee Gas, a natural gas local distribution company. For further information, see Note 17, Segment Information," to the consolidated financial statements.
SECI	Select Energy Contracting, Inc.
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
Woods Electrical	Northeast Acquisition Company, formerly Woods Electrical Co., Inc., a portion of the business of which was sold in April 2006 and the remainder of which was wound down in the second quarter of 2007.

WMECO	Western Massachusetts Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Gas	Yankee Gas Services Company

REGULATORS

CDEP	Connecticut Department of Environmental Protection
DOE	United States Department of Energy
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
SEC	Securities and Exchange Commission

OTHER

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
CfD	Contract for Differences
COLA	Cost of Living Adjustment
Con Edison	Consolidated Edison, Inc.
CTA	Competitive Transition Assessment
CYAPC	Connecticut Yankee Atomic Power Company
EDIT	Excess Deferred Income Taxes
EPS	Earnings Per Share
ES	Default Energy Service
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation No.
FMCC	Federally Mandated Congestion Charges
Globix	Globix Corporation
GSC	Generation Service Charge
GWH	Gigawatt Hours
ISO-NE	New England Independent System Operator or ISO New England, Inc.
KWH or kWh	Kilowatt-hours
KV	Kilovolt
LBCB	Lehman Brothers Commercial Bank, Inc.
LNG	Liquefied Natural Gas
LNS	Local Network Service
LOC	Letter of Credit
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001
Money Pool or Pool	Northeast Utilities Money Pool
MW	Megawatts
MYAPC	Maine Yankee Atomic Power Company
NYMPA	New York Municipal Power Agency
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segments excluding the wholesale

	transmission segment.
Restructuring Settlement	"Agreement to Settle PSNH Restructuring"
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RRB	Rate Reduction Bonds or Rate Reduction Certificates issued by the Regulated Companies
RTO	Regional Transmission Operator
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
TCAM	Transmission Cost Adjustment Mechanism
TSO	Transitional Standard Offer
UI	The United Illuminating Company
UITC	Unamortized Investment Tax Credits
VAR	Voltage Ampere Reactive
VIE	Variable Interest Entity
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, MYAPC and YAEC

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

2008 Form 10-K Annual Report
Table of Contents

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

References in this Annual Report on Form 10-K to "NU," "we," "our," and "us" refer to Northeast Utilities and its consolidated subsidiaries.

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify our "forward-looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward-looking statements are based on the current expectations, estimates, assumptions or projections of management and are not guarantees of future performance. These expectations, estimates, assumptions or projections may vary materially from actual results. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause our actual results to differ materially from those contained in our forward-looking statements, including, but not limited to, actions or inaction by local, state and federal regulatory bodies, changes in business and economic conditions, including their impact on interest rates, bad debt expense, and demand for our products and services, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels and timing of capital expenditures, disruptions in the capital markets or other events that make our access to necessary capital more difficult or costly, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports filed with the Securities and Exchange Commission (SEC) and we encourage you to consult such disclosures.

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

1

PART I

Item 1.

Business

NU, headquartered in Berlin, Connecticut, is a public utility holding company registered with the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned regulated utility subsidiaries:

.

The Connecticut Light and Power Company (CL&P), a regulated electric utility which serves residential, commercial and industrial customers in parts of Connecticut.

.

Public Service Company of New Hampshire (PSNH), a regulated electric utility which serves residential, commercial and industrial customers in parts of New Hampshire.

.

Western Massachusetts Electric Company (WMECO), a regulated electric utility which serves residential, commercial and industrial customers in parts of western Massachusetts; and

.

Yankee Gas Services Company (Yankee Gas), a regulated gas utility which serves residential, commercial and industrial customers in parts of Connecticut.

We sometimes refer to CL&P, PSNH, WMECO and Yankee Gas collectively in this Annual Report on Form 10-K as the "regulated companies."

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises, Inc. (NU Enterprises). We have exited most of these businesses. As of December 31, 2008, NU Enterprises's remaining business consisted of (i) Select Energy Inc. s few remaining wholesale marketing contracts, and (ii) NU Enterprises remaining energy services business.

Although NU consolidated, CL&P, PSNH and WMECO report their financial results separately, we also include information in this report on a segment, or line of business basis. The regulated companies include three business segments: the electric distribution segment (which includes PSNH s regulated generation activities), the natural gas distribution segment and the electric transmission segment. The regulated companies segment of our business represented approximately 99.5 percent of our total earnings for 2008, excluding an after-tax charge of $29.8 million resulting from the settlement of litigation with Consolidated Edison, Inc. (Con Edison), with electric distribution (including PSNH s generation activities) representing approximately 42.6 percent, electric transmission representing approximately 47.6 percent, and natural gas distribution representing approximately 9.3 percent. At December 31, 2008, the NU Enterprises business segment included the following legal entities: (i) Select Energy, Inc. (Select Energy), (ii) Northeast Generation Services Company (NGS), (iii) E.S. Boulos Company (Boulos), (iv) the remaining business of Select Energy Contracting, Inc. (SECI), (iv) NGS Mechanical, Inc., and (v) NU Enterprises parent.

For information regarding each of NU s segments, see Note 17, "Segment Information," to the Consolidated Financial Statements in this Annual Report on Form 10-K.

REGULATED ELECTRIC DISTRIBUTION

General

NU s distribution segment is made up of the distribution businesses of CL&P, PSNH and WMECO, which are primarily engaged in the distribution of electricity in Connecticut, New Hampshire and western Massachusetts, respectively, plus PSNH s regulated electric generation business. The following table shows the sources of 2008 electric franchise retail revenues for NU s electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	**Total Operating Companies**
Residential	55%

Commercial	35%
Industrial	9%
Other	1%
Total	100%

A summary of changes in the operating companies electric kilowatt-hour (kWh) distribution sales for the 12-months ended December 31, 2008 as compared to December 31, 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Electric							
	CL&P		PSNH		WMECO		Total	
	Percentage Decrease	**Weather Normalized Percentage Decrease**	**Percentage (Decrease)/ Increase**	**Weather Normalized Percentage (Decrease)/ Increase**	**Percentage Decrease**	**Weather Normalized Percentage Decrease**	**Percentage Decrease**	**We Norr Perc Dec**
Residential	(4.1)%	(2.7)%	(2.2)%	(1.0)%	(3.1)%	(2.1)%	(3.6)%	
Commercial	(1.3)%	(0.7)%	(1.2)%	(0.4)%	(2.6)%	(2.1)%	(1.4)%	
Industrial	(9.8)%	(9.3)%	(6.1)%	(5.4)%	(8.7)%	(8.5)%	(8.6)%	
Other	(3.2)%	(3.2)%	2.2 %	2.2 %	(14.6)%	(14.6)%	(3.7)%	
Total	(3.7)%	(2.8)%	(2.5)%	(1.6)%	(4.2)%	(3.5)%	(3.5)%	

Retail electric sales in 2008 were lower than those in 2007. The 2008 weather normalized decrease of 2.6 percent reflects the fact that our customers are responding to the volatile costs of energy and to the economic conditions of our region and the nation. We believe customers will continue to respond to these factors and to the recent and ongoing developments in the financial markets resulting in an estimated decline in weather-normalized sales of approximately 1 percent in 2009.

Changes in electric sales, however, have less of an impact on the earnings of our electric distribution companies than in prior years because non-distribution rate revenues, which represented approximately 76 percent of electric distribution company revenues in 2008, are tracked and reconciled to actual costs. Non-distribution rate revenues include the energy, stranded cost, retail transmission and federally mandated congestion charges (FMCC) and other components of rates. For non-distribution rate revenues, the only impact to earnings is from carrying costs on over- or under-recoveries. With respect to our electric distribution company revenues, about two-thirds of CL&P's and WMECO's revenues and about one-half of PSNH's revenues are recovered through charges that are not dependent on overall sales volumes, such as the customer charge and the demand charge.

Comparable to our sales results in 2008, our uncollectibles expense has also been influenced by the adverse economic conditions of our region. Our write-offs as a percentage of revenues increased in 2008 for all our electric distribution companies. Similar to changes in our retail sales, changes in our uncollectibles expense have less of an impact on earnings of our electric distribution companies than in prior years as a portion of the uncollectibles expense for each of the electric distribution companies is allocated to its respective energy supply rate and recovered as a tracked expense.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

CL&P s distribution segment is primarily engaged in the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2008, CL&P furnished retail franchise electric service to approximately 1.2 million customers in 149 cities and towns in Connecticut. CL&P does not own any electric generation facilities.

The following table shows the sources of 2008 electric franchise retail revenues for CL&P based on categories of customers:

CL&P	
Residential	59%
Commercial	34%
Industrial	6%
Other	1%
Total	100%

Rates

CL&P is subject to regulation by the Connecticut Department of Public Utility Control (DPUC) which, among other things, has jurisdiction over rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of facilities. CL&P's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services.

CL&P's retail rates include a delivery service component, which includes distribution, transmission, conservation, renewables, competitive transition assessment (CTA) and other charges that are assessed on all customers. CL&P also has regulatory orders allowing it to recover all or substantially all of its prudently incurred stranded costs, which are pre-restructuring expenditures incurred, or commitments for future expenditures made, on behalf of customers with the expectation such expenditures would continue to be recoverable in the future through rates. CL&P has financed a significant portion of its stranded costs through the issuance of rate reduction certificates or bonds (RRBs) secured by its right to recover stranded costs over time (securitization). CL&P recovers the costs of securitization through the CTA component of its rates. In addition to those stranded costs being recovered through securitization, CL&P s stranded costs included, as of December 31, 2008, ongoing independent power producer costs and costs associated with the ongoing decommissioning of the Maine Yankee, Connecticut Yankee and Yankee Rowe nuclear units.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers while retaining CL&P as their electric distribution company. Under "Standard Service" rates for customers with less than 500 kW of demand and "Supplier of Last Resort Service" rates for customers with 500 kW of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes through the cost to ratepayers through the "Generation Service Charge" and the "Bypassable Federally Mandated Congestion Charge" (FMCC) components of the customer s bill, which are adjusted and reconciled on a semi-annual basis.

A large percentage of CL&P's customers have continued to buy their power from CL&P at Standard Service rates or Supplier of Last Resort Service rates. However, CL&P has experienced some customer migration to competitive energy suppliers, with the movement concentrated among larger customers. Because this customer migration is only for energy supply service, there is no impact on the delivery portion of the business or the operating income of CL&P.

CL&P adjusts its retail transmission rates on a regular basis, thereby recovering all of its retail transmission expenses on a timely basis. (See "Regulated Electric Transmission" in this Annual Report on Form 10-K).

On January 28, 2008, the DPUC approved $77.8 million, or 11.7 percent, and $20.1 million, or 2.6 percent, in annual increases in CL&P s distribution rates, effective February 1, 2008 and February 1, 2009, respectively. The rate decision included an ROE of 9.4 percent, with CL&P continuing its earnings sharing mechanism, which provides that ratepayers and shareholders share equally in any earnings in excess of its allowed regulatory ROE. For further information on CL&P rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

Regulatory Update

On May 2, 2008, the DPUC approved CL&P s revised metering compliance plan that would meet the DPUC's objective of making time-of-use rates available to CL&P customers. The DPUC decision authorized a pilot program involving the installation of advanced metering infrastructure (AMI) meters and a rate design pilot to test new time-of-use and real-time rates to determine customer acceptance and load response to various pricing structures. CL&P expects to conduct the AMI pilot with approximately 3,000 customers during the summer of 2009. The estimated incremental cost of the program is expected to be between $10.6 million to $13 million and such costs are authorized to be recovered from customers, initially through CL&P s FMCC charges. The non-incremental operating and maintenance expenses are projected to be less than $2 million.

In 2008, pursuant to Connecticut's "Act Concerning Energy Independence," (Energy Independence Act), CL&P signed five contracts and The United Illuminating Company (UI) signed two contracts, each to purchase energy, capacity and renewable energy credits from planned renewable energy plants, including biomass and fuel cell projects, approved by the DPUC, for a total of 109 MW. CL&P had also signed one contract with a biomass project in 2007 to purchase 15 MW of its output. Purchases under the contracts are scheduled to begin in 2009 through 2011 and to extend for periods ranging from 15 to 20 years. As directed by the DPUC, CL&P and UI have also signed a sharing agreement under which they will share the costs and benefits of these contracts, with 80 percent to CL&P and 20 percent to UI. On January 16, 2009, the DPUC issued a draft decision selecting two additional renewable energy projects for a total of 6 MW with which CL&P or UI will sign similar contracts. The final decision is scheduled for March 11, 2009. Additional projects are expected to be selected by the DPUC to achieve a total of 150 MW of additional renewable energy sources in Connecticut. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

Also in 2008, CL&P and UI entered into contracts for differences (Peaker CfDs) with developers of three proposed peaking generation units totaling 506 MW of summer peaking capacity, as approved by the DPUC. The Peaker CfDs provide for the payment to the developer of the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. As directed by the DPUC, CL&P and UI will share the net costs and benefits of the Peaker CfDs on a basis of 80 percent and 20 percent, respectively. CL&P s portion of the costs and benefits will be paid by or refunded to its customers

In 2008, the DPUC issued final decisions in a docket examining the manner of operation and accuracy of CL&P's electric meters and in a docket investigating CL&P billing errors involving approximately 2,000 customers on time of use rates. In the metering docket decision, the DPUC did not fine CL&P, but held that possibility open if CL&P fails to meet benchmarks to be established in the docket. The decision in the time-of-use docket disallowed recovery from customers of the incremental costs associated either directly or indirectly with the billing errors. These incremental costs are not material and have been expensed as incurred.

In prior years, CL&P has submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its Transition Service energy procurement fee, which was effective through 2006 and had requested approval of a pre-tax $5.8 million 2004 incentive fee. In December 2005, the DPUC issued a draft decision authorizing the $5.8 million incentive fee and CL&P recovered the $5.8 million amount by recording it in 2005 earnings through the CTA reconciliation process. CL&P has not recorded any amounts in earnings related to the 2005 or 2006 procurement fee. On January 15, 2009, the DPUC issued a final decision on the 2004 incentive fee that reversed its December 2005 draft decision, and concluded that CL&P was not eligible for the procurement incentive compensation for 2004. As a result, the $5.8 million pre-tax charge was recorded in CL&P s 2008 earnings, and an obligation to refund the $5.8 million to customers was established in the CTA reconciliation process as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

For further information on regulatory actions affecting CL&P, see "Regulatory Developments and Rate Matters - Connecticut - CL&P" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases its energy requirements to serve its Standard Service and Supplier of Last Resort Service loads from a variety of competitive sources through periodic requests for proposals (RFPs). CL&P issues RFPs periodically for periods of up to three years to layer Standard Service full requirements supply contracts in order to mitigate price volatility for its residential and small and medium commercial and industrial customers. CL&P issues RFPs for Supplier of Last Resort service for larger commercial and industrial customers every three months. Currently, CL&P has in place contracts with various suppliers through 2010 for Standard Service and to date one tranche has been filled for 2011.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH s distribution segment (which includes its regulated generation) is primarily engaged in the generation, purchase, delivery and sale of electricity to its residential, commercial and industrial customers. At December 31, 2008, PSNH furnished retail franchise electric service to approximately 493,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of electricity generation assets. Approximately 70 MW of those generation assets are hydroelectric units. Included among these generating assets is a 50 MW wood-burning generating unit (Northern Woods Power Project) at its Schiller Station in Portsmouth, New Hampshire, which was converted from a coal-burning unit in December 2006.

The following table shows the sources of 2008 electric franchise retail revenues based on categories of customers:

PSNH	
Residential	44%
Commercial	40%
Industrial	16%
Total	100%

Rates

PSNH is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) which has jurisdiction over, among other things, rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of facilities.

PSNH s Energy Service (ES) rate recovers PSNH's generation and purchased power costs, including an ROE on PSNH's generation assets. PSNH files for approval of updated ES rates annually with the NHPUC, with a six-month true-up, to ensure timely recovery of its costs. PSNH defers for future recovery or refund any difference between its ES revenues and the actual costs incurred.

On July 1, 2008, PSNH s Delivery Service (DS) rates decreased by $0.4 million annually. This amount consisted of a $3.4 million rate reduction related to the full recovery of a rate differential recoupment and an increase of approximately $3 million per year for a two-year period effective July 1, 2008 to eliminate a negative balance in the major storm cost reserve and restore the intended reserve level of $1 million.

Pursuant to a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the Office of Consumer Advocate, the NHPUC approved PSNH s petition seeking to establish a Transmission Cost Adjusting Mechanism (TCAM) rate to be reset annually consistent with the rate settlement agreement. On May 13, 2008, PSNH filed a July 1, 2007 through June 30, 2008 TCAM reconciliation and a projected TCAM rate to be billed effective July 1, 2008 related to July 1, 2008 through June 30, 2009 TCAM costs.

Under New Hampshire law, the Stranded Cost Recovery Charge (SCRC) allows PSNH to recover its stranded costs, including expenses incurred through mandated power contracts and other long-term investments and obligations. PSNH has financed a significant portion of its stranded costs through securitization by issuing RRBs secured by the right to recover these stranded costs from customers over time. It recovers the costs of these bonds through the SCRC rate. On an annual basis, PSNH makes an SCRC reconciliation filing with the NHPUC for the previous year. For further information on PSNH rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

Under the terms of the order issued by the NHPUC approving PSNH s Northern Wood Power Project, which replaced one of the three 50 MW boiler units at the coal-fired Schiller Station, certain revenue, credits and cost avoidances (revenue sources) are shared between PSNH and its customers. These revenue sources include sales of renewable energy certificates (RECs) to other utilities, brokers, or suppliers, and production tax credits. In any given year, if the combination of revenue sources falls short of a stipulated revenue level, PSNH and its customers each share half of any deficiency, and if the combination exceeds the stipulated revenue level, PSNH and its customers each share half of any excess. The Northern Wood Power Project entered commercial operation on December 1, 2006, and revenue sources exceeded stipulated levels in 2008 due to its performance and favorable pricing in the Massachusetts and Rhode Island markets for the RECs. As a result, customers and shareholders will share equally a benefit of about $7.8 million of incremental revenues for 2008.

Although PSNH's customers are entitled to choose competitive energy suppliers, PSNH has experienced only a small amount of customer migration to date.

On December 11, 2008, a major ice storm struck portions of New England, severely damaging PSNH s distribution systems. This was the most severe ice storm in PSNH s history. Of the 440,000 New Hampshire homes and businesses that lost power, 322,000 were served by PSNH. Restoration operations commenced on December 11, 2008 and were substantially completed by December 25, 2008. PSNH utilized its own line crews, local contractors, line crews from other NU subsidiaries and numerous other line crews from the eastern United States and Canada.

The operating cost of storm restorations that meet a NHPUC specified criteria are funded through the Major Storm Costs Reserve (MSCR). Capital costs for any storm work are charged to property, plant and equipment and are recovered through the normal distribution ratemaking process. As the December 2008 ice storm met the MSCR criteria, $62.7 million of total estimated repair costs of $75 million associated with this storm were charged to the MSCR at December 31, 2008. PSNH intends to request recovery of these costs as part of its next delivery rate proceeding with the NHPUC. Out of the remaining total storm costs incurred through December 31, 2008, $6.5 million has been expensed and $5.6 million has been capitalized to plant and equipment. PSNH expects to recognize an additional $10 million in 2009 when the weather is warmer and additional clean-up and repairs can be performed. We carry $15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to PSNH to reduce the amount of deferred or expensed storm costs.

Regulatory Update

In 2006, New Hampshire enacted a law requiring PSNH to reduce the mercury emissions for its coal fired plants by at least 80 percent (with co-benefits of reduction in sulfur dioxide (SO2) emissions as well). Wet scrubber technology will be installed at Merrimack Station in Bow New Hampshire no later than July 1, 2013. Following an August 2008 announcement by PSNH that the cost of this installation would be increasing from the original estimate of $250 million to $457 million, the NHPUC opened an inquiry to determine whether it had authority to assess whether the project is in the public interest. In September 2008, the NHPUC ruled that its authority is limited to determining at a later time the prudence of the costs incurred in complying with the legislation. In October 2008, several parties filed motions with the NHPUC requesting a reconsideration of its ruling; these motions were rejected. On December 11, 2008, several parties involved in the filing of the October 2008 motion for a rehearing filed an appeal with the New Hampshire Supreme Court requesting that the Court overturn the NHPUC finding that it lacked present authority over this matter. The Supreme Court has indicated that it will hear this appeal, but has not yet issued a schedule for oral arguments.

In July 2008, New Hampshire passed a law establishing a transmission commission responsible for developing a proposal to expand the electric transmission system in northern New Hampshire to encourage the development of new renewable generation sources. On December 1, 2008, the transmission commission submitted its progress report, which concluded that New Hampshire should continue to pursue the upgrade of transmission capacity in its northern region to allow development of its native renewable energy resources. Also, the transmission commission should continue to pursue both local and regional cost allocation issues related to the transmission expansion. We believe the northern New Hampshire region has the potential for over 500 MW of new renewable resources. PSNH has included $130 million in its 2009 to 2013 capital plan for transmission upgrades in the region which assumes that these projects are built and a cost allocation solution can be agreed to by relevant parties.

In July 2008, New Hampshire passed a law authorizing rate recovery by electric public utilities of investments made in distributed energy resources up to 5 MW, such as renewable energy generation. The total investment is limited to resources having a capability equal to 6 percent of a distribution utility s peak load. PSNH has not yet included any distributed energy resource investment opportunities in its capital expenditure plans.

Sources and Availability of Electric Power Supply

During 2008, about 67 percent of PSNH s load was met through its own generation and long-term power supply rate orders and contracts with third parties. The remaining 33 percent of PSNH's load was met by short-term (less than one year) purchases and spot purchases in the competitive New England wholesale power market. PSNH expects to meet its load requirements in 2009 in a similar manner.

New Hampshire s "Renewable Energy Act" establishes renewable portfolio standards for electricity sold in the state that require annual increases in the percentage of the electricity sold to retail customers having direct ties to renewable sources. The renewable sourcing requirements began in 2008 and increase each year to reach 23.8 percent by 2025. PSNH plans to meet these standards, in part, through the purchase of Renewable Energy Certificates (RECs) from qualified renewable energy resources. For each MWH of energy produced from a qualifying resource, the producer will receive one REC. Energy suppliers, like PSNH, will purchase these RECs from the producers and will use them to satisfy the RPS requirements. To the extent that PSNH is unable to purchase sufficient RECs, it will be required to make up the difference between the RECs purchased and its total obligation by making an alternative compliance payment (ACP) for each REC requirement for which PSNH is deficient. The costs of both the RECs and ACPs do not impact earnings, as these costs are being recovered by PSNH through its ES rates. For further information, see "Regulatory Developments and Rate Matters - New Hampshire" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO s distribution segment is engaged in the purchase, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2008, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western third of Massachusetts. WMECO does not own any electricity generating facilities. On December 31, 2008, WMECO purchased all of the transmission-related assets of its affiliates, Holyoke Water Power Company (HWP) and Holyoke Power and Electric Company (HP&E) for approximately $4 million.

The following table shows the sources of 2008 electric franchise retail revenues based on categories of customers:

WMECO	
Residential	58%
Commercial	32%
Industrial	9%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts Department of Public Utilities (DPU), which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities. WMECO's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. Massachusetts utilities are entitled under state law to charge rates that are sufficient to allow them an opportunity to cover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under state law, all of WMECO's customers are now entitled to choose their energy suppliers, while retaining WMECO as their distribution company. WMECO purchases electric power for and passes through the cost to those customers who do not choose a competitive energy supplier (basic service). Basic service charges are adjusted and reconciled on an annual basis. Most of WMECO's residential and smaller customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and business customers have opted for a competitive energy supplier.

WMECO collects its transmission costs through a transmission adjustment clause, which is adjusted annually, thereby allowing WMECO to recover all of its retail transmission expenses on a timely basis.

WMECO also has regulatory orders allowing it to recover all or substantially all of its prudently incurred stranded costs. WMECO has financed a portion of its stranded costs through securitization by issuing RRBs secured by the right to recover stranded costs from customers over time. It is recovering the costs of securitization through rates.

On January 1, 2008, WMECO s distribution rates increased by $3 million annually as approved by the Massachusetts DPU in December 2006. WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. On December 29 and 30, 2008, the DPU approved WMECO s proposed rate changes effective January 1, 2009. The rate changes were made in accordance with WMECO s various tracking mechanisms.

The major ice storm on December 11, 2008 also impacted parts of Massachusetts, including areas served by WMECO. As this storm met the storm costs reserve criteria approved in WMECO s last distribution rate case settlement, $11.3 million of the total $13.8 million estimated repair costs associated with this storm were recognized as a deferred asset at December 31, 2008. WMECO expects to begin recovery of these costs in its next distribution rate proceeding. The DPU has opened a formal docket to review storm restoration efforts by the state's utilities.

For further information on WMECO s rates, see "Regulatory Developments and Rate Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

Regulatory Update

On July 16, 2008, the DPU issued a decision in its decoupling generic docket requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. The decision rejected calls for partial decoupling or decoupling by rate design in favor of full decoupling by rate class. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. That case will include a proposal to fully decouple distribution revenues from kilowatt-hour sales.

As part of WMECO s December 2006 rate case settlement agreement approved by the DPU, WMECO became subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred are paid to customers through a method approved by the DPU. WMECO will likely be required to pay an assessment charge for its 2008 reliability performance against the metrics established for 2008, primarily as a result of significant storm activity. WMECO has performed at target for other non-storm related reliability metrics. WMECO will file its 2008 SQ results and assessment calculation with the DPU in March 2009. In 2008, WMECO recorded an estimated pre-tax charge and a regulatory liability of approximately $1.3 million for this assessment.

In July 2008, Massachusetts enacted "The Green Communities Act of 2007." Aimed at increasing energy efficiency (EE) and the use of renewable resources in the state, the Act contains many provisions important to the state s utilities. In addition to adopting RGGI requirements, the Act:

.

Removes the cap on utility expenditures for EE and demand response (DR).

.

Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;

.

Requires utilities to sign long-term contracts for renewable resources;

.

Allows each utility to own and operate up to 50 MW of solar generation;

.

Requires utilities to file a plan with the DPU for a smart grid pilot; and

.

Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

By April 30, 2009, WMECO is required to prepare a three-year EE and DR investment plan related to the cost of EE and DR programs established by the Act for review by the Energy Efficiency Council and, ultimately, the DPU. In addition, WMECO filed a program with the DPU on February 11, 2009 providing for a three-phase solar generation program subject to DPU authorization prior to each phase. The initial phase calls for 6 MW of solar generation to be installed at eight host sites in WMECO's service territory upon receipt of DPU approval. This phase of the project is expected to be completed as early as 2010 at a cost of approximately $42 million. The second phase includes an additional 9 MW extending through 2012, and the third and final phase could increase total capacity to the 50 MW maximum. The DPU has six months to issue a decision on WMECO's plan. WMECO is otherwise precluded from making new generation investments, but has not yet included any solar generation investment opportunities in its capital expenditure plans.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets and purchases its energy requirements from a variety of competitive sources through periodic RFPs. For basic service power supply, WMECO issues RFPs periodically, consistent with DPU regulations. On May 14, 2008, WMECO entered into an agreement to secure 50 percent of residential, small commercial and industrial, and street lighting loads for the July 1, 2008 through June 30, 2009 period, and on November 3, 2008 WMECO entered into an agreement to secure power for half of its residential, small commercial and industrial, and street lighting loads for the January 1 through December 31, 2009 period. WMECO will issue an RFP in the second quarter of 2009 to secure the remaining 50 percent of its residential, small commercial and industrial, and street lighting loads for the July 1 through December 31, 2009 period and 50 percent of the load for January 1, 2010 through June 30, 2010. For its large commercial and industrial customers, WMECO entered into an agreement on November 3, 2008 to secure power for the first quarter of 2009 and an agreement to secure power for the second quarter 2009 on February 10, 2009. RFPs will be issued quarterly to secure power for the balance of the year.

REGULATED GAS DISTRIBUTION

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 200,000), and size of service territory (2,088 square miles). Total throughput (sales and transportation) in 2008 was 49.8 billion cubic feet (Bcf) compared with 49.7 Bcf in 2007. Yankee Gas provides firm gas sales service to customers who require a continuous gas supply throughout the year, such as residential customers who rely on gas for their heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase gas from Yankee Gas. Yankee Gas also offers firm transportation service to its commercial and industrial customers who purchase gas from sources other than Yankee Gas as well as interruptible transportation and interruptible gas sales service to those certain commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice. Yankee Gas can interrupt service to these customers during peak demand periods or at any other time to maintain distribution system integrity. In 2007, Yankee Gas completed construction of a liquefied natural gas (LNG) facility in Waterbury, Connecticut. The LNG facility is capable of storing the equivalent of 1.2 Bcf of natural gas.

Yankee Gas earned $27.1 million on total gas operating revenues of approximately $577.4 million for 2008. The following table shows the sources of 2008 total gas operating revenues:

Yankee Gas	
Residential	45%
Commercial	29%
Industrial	23%

Other	3%
Total	100%

For more information regarding Yankee Gas s financial results, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data," which includes Note 17, "Segment Information," contained within this Annual Report on Form 10-K.

A summary of changes in Yankee Gas firm natural gas sales for 2008 as compared to 2007 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Yankee Gas	
	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase
Residential	(2.0)%	(0.1)%
Commercial	(0.2)%	1.4%
Industrial	9.2%	9.6%
Total	2.1%	3.4%

Firm natural gas sales for 2008 were higher than 2007. The 2008 results reflect warmer weather in the first quarter, colder weather in the fourth quarter and an increase in industrial sales primarily due to customer-owned gas-fired distributed generation and favorable natural gas prices relative to oil. We have assumed an increase in weather normalized firm natural gas sales of approximately 2.5 percent in 2009. Similar to our electric distribution companies, Yankee Gas recovers a significant portion of its distribution revenues (approximately 40 percent) through charges that are not dependent on usage.

Although Yankee Gas is not subject to the FERC's jurisdiction, the FERC has limited oversight with respect to certain reporting and intrastate gas transportation that Yankee Gas provides. In addition, the FERC regulates the interstate pipelines serving Yankee Gas s service territory.

Rates

Yankee Gas is subject to regulation by the DPUC, which has jurisdiction over, among other things, rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities.

Yankee Gas recovers its cost of gas supplied to customers through a Purchased Gas Adjustment (PGA) clause in its rate tariff. In 2005 and 2006, the DPUC issued decisions requiring an audit by an independent party of approximately

$11 million in previously recovered PGA revenues associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order pursuant to which Yankee Gas was required to refund to customers approximately $5.8 million in recoveries under its Purchased Gas Adjustment clause. Yankee Gas results for 2008 reflect an after-tax charge of $3.5 million associated with that decision.

Under a settlement of its distribution rate filing with the Connecticut Office of Consumer Counsel and the DPUC s Prosecutorial Division, Yankee Gas s base rate increased, effective July 1, 2007, by $22 million, or 4.2 percent, net of expected pipeline and commodity cost savings resulting primarily from completion of Yankee Gas s LNG facility, and Yankee Gas was allowed an authorized ROE of 10.1 percent. Yankee Gas will return to ratepayers 100 percent of all earnings in excess of the allowed 10.1 percent ROE. As a result of the base rate increase, the amount of gas supply costs charged to customers through the PGA decreased.

FORWARD CAPACITY MARKETS

On December 1, 2006, a FERC-approved Forward Capacity Market (FCM) settlement agreement was implemented, and the payment of fixed compensation to generators began. The second forward capacity auction concluded on December 10, 2008 for the capacity year June 2011 through May 2012. The bidding reached the established minimum of $3.60 per kilowatt-month with 4,755 MW of excess remaining capacity. This means the effective price will be $3.12 per kilowatt-month compared to the equivalent first forward capacity auction price of $4.25 per kilowatt-month for the 12-month capacity period ending May 31, 2011 and $4.10 per kilowatt-month for the 12-month capacity period ending May 31, 2010. These costs are recoverable in all jurisdictions through the currently established rate structures.

REGULATED ELECTRIC TRANSMISSION

General

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

Wholesale Transmission Rates

Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under ISO-NE s FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes the Regional Network Service (RNS) and Local Network Service (LNS) rate schedules, among other things. The RNS rate, administered by ISO-NE and billed to all New England transmission owners, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not covered under the RNS rate, including 100 percent of the construction costs of the New England East-West Solutions (NEEWS) projects. Both the LNS and RNS rates provide for annual true-ups to actual costs. The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e. RNS, rental, etc.), thereby ensuring that we recover all regional and local revenue requirements as described in Tariff No. 3.

FERC ROE Decision

On March 24, 2008, the FERC issued an order on rehearing confirming its initial order setting the base ROE on transmission projects for the New England transmission owners, including NU s subsidiaries. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC s earlier decision granting a 100 basis point adder for new transmission projects that are built as part of the ISO-NE Regional System Plan and are "completed and on line" by December 31, 2008. In order to receive incentives for projects completed after December 31, 2008, transmission owners are required to make project-specific incentive requests that meet the nexus requirements under FERC guidelines for new projects. In 2008, we recognized $6 million in transmission segment earnings related to this order. This order has been appealed to the D.C. Circuit Court of Appeals by various state regulators and consumer advocates. The court has set a schedule for the briefing to be concluded in the second quarter of 2009, with no date set for argument.

On May 16, 2008, CL&P filed an application with the FERC to receive ROE incentives for its portions of the Middletown-Norwalk project seeking a waiver of the "completed and on line" date of December 31, 2008 to earn the ROE incentives. Alternatively, CL&P asked FERC to find that this project met the nexus test requirements for incentives under FERC s guidelines for new projects, and also requested an additional 50 basis point adder for advanced technology used in the project. FERC subsequently granted the waiver request and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also found that the project met the nexus test, and granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project. CL&P completed the project by the end of 2008. The 50 basis point adder results in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent, which represents the overall ROE limit established by FERC. Certain state regulators and municipal utilities had sought rehearing which was denied by FERC and Connecticut state regulators have since appealed the order to the D.C. Circuit Court of Appeals.

On November 17, 2008, the FERC issued an order granting certain incentives and rate amendments to National Grid USA (National Grid) and us, for certain components of the proposed NEEWS projects. The approved incentives included (1) an ROE of 12.89 percent, which includes an incentive of 125 basis points; (2) inclusion of 100 percent construction work in progress (CWIP) costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our or National Grid's control. Our portion of the components that received these incentives is estimated to cost approximately $1.41 billion of our $1.49 billion share of the total NEEWS projects. Several parties have sought rehearing of this FERC order on which FERC has not yet acted.

Transmission Projects

In December 2008, we completed the last of our four southwest Connecticut transmission upgrades. The first of those projects, a new 345KV/115KV overhead and underground line between Bethel, Connecticut and Norwalk, Connecticut, was placed in service in October 2006. The remaining three projects were placed in service in 2008. The Middletown-Norwalk project, a 69-mile, 345KV/115 KV transmission project from Middletown to Norwalk, Connecticut constructed jointly with UI, was completed in December 2008. CL&P's portion of this project cost approximately $950 million, $100 million lower than our earlier cost estimate. The 45-mile overhead section of the project entered service on August 28, 2008 and the 24-mile underground section entered service on December 16, 2008. The Glenbrook Cables project, a two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut entered service on November 11, 2008 at a project cost of approximately $239 million, $16 million higher than previous estimates due to increased construction costs to remove underground obstacles. The Long Island Replacement Cable project, a 138KV, 11-mile undersea transmission project between Norwalk, Connecticut and Northport-Long Island, New York was completed in September 2008. CL&P owns 51 percent of the project, with Long Island Power Authority owning the remainder, and CL&P's portion of the project costs is anticipated to be approximately $78 million.

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

The first of the NEEWS projects, the Greater Springfield Reliability Project, which involves a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. This project is expected

to cost approximately $714 million if built according to our preferred route and configuration. CL&P filed its application to build the Connecticut portion of the Greater Springfield Reliability Project with the Connecticut Siting Council (Siting Council) on October 20, 2008 and WMECO filed its application to build its portion of the project with the Massachusetts Energy Facilities Siting Board on October 27, 2008. The Connecticut Energy Advisory Board is currently reviewing Connecticut-based generation, demand side management and other proposed alternatives to the Greater Springfield Reliability Project, which must be submitted to the Siting Council by March 19, 2009. The Siting Council has preliminarily set dates for hearings, public comments and site visits on the Connecticut portion of the project in the second quarter of 2009. If the overall project is approved in 2010 as expected, we currently expect to commence construction in late 2010 and place the project in service in 2013.

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

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide us with another 345 KV connection to move power across the state of Connecticut. The timing of this project would be six to twelve months behind the other two projects, and CL&P currently expects to file the siting application in early 2010 with construction beginning in 2011. The project is currently expected to be placed in service in 2013 at a cost of approximately $315 million. Included as part of NEEWS are approximately $210 million of associated reliability related expenditures, some of which may be incurred in advance of the three major projects.

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

On December 12, 2008, we submitted jointly with NSTAR, a petition with the FERC requesting a declaratory order that would allow us and NSTAR to enter into a bilateral transmission services agreement with H.Q. Energy Services (U.S.) Inc. (HQUS), a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR subsidiaries would sell to HQUS 1,200 megawatts of firm electric transmission service over a new, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver this same amount of firm electric power from Canadian low-carbon energy resources to New England.

If FERC issues the declaratory order as we anticipate, NU and NSTAR would subsequently seek approval from FERC of the specific terms and conditions of the transmission arrangement and approvals from state regulators of the terms and conditions of the power purchase arrangements. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. This project would provide a competitive source of low-carbon power that is favorable in comparison to current alternatives. It also would provide for an expansion of New England s transmission system without raising regional transmission rates.

NU, NSTAR and HQUS have also begun discussions on the specifics of a potential long-term power purchase agreement that would ensure the line is utilized to bring low-carbon power to benefit New England customers. A FERC order is expected in the first half of 2009, and if the order approves the proposal, then NU and NSTAR plan to negotiate a power purchase agreement with HQUS later in 2009. The terms of such an agreement would be subject to regulatory approval in several states.

Assuming completion of an acceptable power purchase agreement, and receipt of all necessary state and federal regulatory approvals, we expect this project to be under construction between 2011 and 2014. Our initial estimate of our portion of the construction funding is approximately $525 million. HQUS will reimburse NU and NSTAR for the total costs of this project, including an investment return to these companies, over the estimated 40-year operating life of the transmission line. NU and NSTAR s intent is to create an agreement that approximates a typical FERC approved cost-of-service rate structure. The revenue recovery model will ultimately require FERC approval.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects enter rate base once they are placed in commercial operation. Additionally, 100 percent of the NEEWS projects will enter rate base during their construction period. At the end of 2008, our transmission rate base was approximately $2.4 billion, including approximately $2.0 billion at CL&P, $250 million at PSNH and $80 million at WMECO. We forecast that our total transmission rate base will grow to approximately $5.0 billion by the end of 2013. This increase in transmission rate base is driven by the need to improve the capacity and reliability of our regulated transmission system.

A summary of projected year-end transmission rate base by regulated company is as follows (millions of dollars):

Company	**2009**	**2010**	**2011**	**2012**	**2013**
CL&P	$2,024	$2,033	$2,224	$2,433	$2,454
PSNH	314	325	666	1,089	1,189
WMECO	125	218	488	729	876
Other	-	-	-	-	525
Totals	$2,463	$2,576	$3,378	$4,251	$5,044

The projected rate base amounts reflected above assume that $1.49 billion in transmission projects associated with NEEWS will be completed before the end of 2013 and the transmission line connecting to HQUS is built. Numerous factors, some of which are beyond our control, may impact the rate base amounts above, including the level and timing of capital expenditures and plant placed in service and regulatory approvals. For more information regarding Regulated Transmission matters, see "Transmission Rate Matters and FERC Regulatory Issues" and "Business Development and Capital Expenditures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in this Annual Report on Form 10-K.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding the existing electric transmission and distribution system and natural gas distribution system. Our consolidated capital expenditures in 2008, including amounts incurred but not paid, cost of removal, allowance for funds used during construction and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors in determining rate base), totaled approximately $1.3 billion, almost all of which was expended by the regulated companies. The capital expenditures of these companies in 2009 are estimated to total approximately $851 million. Of this amount, approximately $375 million is expected to be expended by CL&P, $310 million by PSNH, $100 million by WMECO and $66 million by Yankee Gas. This capital budget includes anticipated costs for all committed capital projects (i.e., generation, transmission, distribution, environmental compliance and others) and those reasonably expected to become committed projects in 2009. We expect to evaluate needs beyond 2009 in light of future developments, such as restructuring, industry consolidation, performance and other events. Increases in proposed distribution capital expenditures stems primarily from increasing labor and material costs and an aging infrastructure. The costs (both labor and material) that our regulated companies incur to construct and maintain their electric delivery systems have increased dramatically in recent years. These increases have been driven primarily by higher demand for commodities and electrical products, as well as increased demand for skilled labor. Our regulated companies have many major classes of equipment that are approaching or beyond their useful lives, such as old and obsolete distribution poles, underground primary cables and substation switchgear. Replacement of this equipment is extremely costly.

CL&P s transmission capital expenditures in 2008 totaled approximately $586 million. The decrease in transmission segment capital expenditures in 2008 as compared with 2007 was primarily due to the early completion of the major southwest Connecticut transmission projects discussed above. For 2009, CL&P projects transmission capital expenditures of approximately $97 million. During the period 2009 through 2013, CL&P plans to invest approximately $974 million in transmission projects, the majority of which will be for NEEWS.

In addition to its transmission projects, CL&P plans distribution capital expenditures to meet growth requirements and improve the reliability of its distribution system. In 2008, CL&P's distribution capital expenditures totaled approximately $297 million. CL&P projects its distribution capital expenditures in 2009 to be approximately $278 million. CL&P plans to spend approximately $1.59 billion on distribution projects during the period 2009-2013. If all of the distribution and transmission projects are built as proposed, CL&P s rate base for electric transmission is projected to increase from approximately $2.0 billion at the end of 2008 to approximately $2.5 billion by the end of 2013, and its rate base for distribution assets is projected to increase from approximately $2.0 billion to approximately $3.0 billion over the same period.

In 2008, PSNH's transmission capital expenditures totaled approximately $82 million, its distribution capital expenditures totaled $98 million and its generation capital expenditures totaled $74 million. For 2009, PSNH projects transmission capital expenditures of approximately $58 million, distribution capital expenditures of approximately $96 million and generation capital expenditures of approximately $156 million. The increase in generation capital expenditures is mostly due to the expenditures for the Merrimack Clean Air project. During the period 2009-2013, PSNH plans to spend approximately $1.1 billion on transmission projects, approximately $559 million on distribution projects, and $623 million on generation projects. If all of the distribution, generation and transmission projects are built as proposed, PSNH s rate base for electric transmission is projected to increase from approximately $250 million at the end of 2008 to approximately $1.2 billion by the end of 2013, and its rate base for distribution and generation assets is projected to increase from approximately $1.0 billion to approximately $2.0 billion over the same period.

In 2008, WMECO's transmission capital expenditures totaled approximately $44.2 million and its distribution capital expenditures totaled approximately $37.8 million. In 2009, WMECO projects transmission capital expenditures of approximately $70 million and distribution capital expenditures of approximately $30 million. During the period 2009-2013, WMECO plans to spend approximately $888 million on transmission projects, with the bulk of that amount to be spent on the NEEWS Greater Springfield Reliability Project, and approximately $168 million on distribution projects. If all of the distribution and transmission projects are built as proposed, WMECO s rate base for electric transmission is projected to increase to approximately $876 million by the end of 2013 and its rate base for distribution assets is projected to increase from approximately $374 million to approximately $497 million over the same period.

In 2008, Yankee Gas s capital expenditures totaled approximately $44 million. For 2009, Yankee Gas projects total capital expenditures of approximately $66 million. During the period 2009-2013, Yankee Gas plans on making approximately $399 million of capital expenditures. If all of Yankee Gas s projects are built as proposed, Yankee Gas s investment in its regulated assets is projected to increase from approximately $685 million at the end of 2008 to approximately $890 million by the end of 2013.

For more information regarding NU and its subsidiaries' construction and capital improvement programs, see "Business Development and Capital Expenditures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in this Annual Report on Form 10-K.

STATUS OF EXIT FROM COMPETITIVE ENERGY BUSINESSES

Since 2005, we have been in the process of exiting our competitive energy businesses and are now focusing exclusively on our regulated businesses. At December 31, 2008, our competitive businesses consisted solely of (i) Select Energy s few remaining wholesale marketing contracts and NGS and its affiliates, which are winding down, and (ii) Boulos, NU Enterprises remaining active energy services business.

On May 31, 2008, Select Energy s remaining wholesale sales contract in the PJM power pool expired. Select Energy s wholesale contract with The New York Municipal Power Agency (NYMPA) and related supply contracts expire in 2013. In addition to the PJM and NYMPA contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to operate and purchase the output of a certain generating facility in New England through 2012.

For more information regarding the exit of the competitive businesses, see "NU Enterprises Divestitures" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements, contained within this Annual Report on Form 10-K.

FINANCING

We paid dividends on our common shares totaling $129.1 million in 2008, compared to $121 million in 2007, reflecting increases in the quarterly dividend amount that were effective in the third quarters of 2007 and 2008. On February 10, 2009, the NU Board of Trustees declared a quarterly dividend of $0.2375 per share, payable on March 31, 2009, an increase of $0.10 per share above the previous annualized rate of $0.85 per share. This dividend reflects the company s policy, announced in November 2008, of targeting a dividend payout ratio of approximately 50 percent of earnings, with a goal of continuing the policy of increasing the dividend at a rate above industry average and providing an attractive return to shareholders. NU expects to revisit its dividend levels in the first quarter of each year.

In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In 2008, CL&P, PSNH, WMECO and Yankee Gas paid $106.5 million, $36.4 million, $39.7 million, and $31 million, respectively, in common dividends to NU parent. In 2008, NU parent contributed $210 million of equity to CL&P, $75.6 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

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

Our total debt, including short-term debt, capitalized lease obligations and prior spent nuclear fuel liabilities, but not including RRBs, was approximately $4.8 billion as of December 31, 2008.

During 2008, the NU companies issued an aggregate of $760 million of long-term debt, as follows: On May 27, 2008, CL&P issued $300 million of 10-year first and refunding mortgage bonds carrying a coupon rate of 5.65 percent, and PSNH issued $110 million of 10-year first mortgage bonds with a coupon rate of 6.00 percent. On June 5, 2008, NU parent issued $250 million of five-year senior unsecured notes with a coupon rate of 5.65 percent, and on October 7, 2008, Yankee Gas issued $100 million of 10-year first mortgage bonds at 6.9 percent. In addition, on February 13, 2009, CL&P issued $250 million of 10-year first mortgage bonds at 5.5 percent.

NU parent has a combined credit line and letter of credit (LOC) facility in a nominal aggregate amount of $500 million, including the lending commitment of Lehman Brothers Commercial Bank, Inc. (LBCB) (as discussed below), which expires on November 6, 2010. At December 31, 2008, NU parent had $304 million of borrowings and $87 million of LOCs issued for the benefit of certain subsidiaries outstanding under that facility. NU parent had approximately $50 million of borrowing availability on this facility as of February 25, 2009, excluding the remaining unfunded commitment of LBCB. NU also had approximately $466 million of externally invested cash at February 25, 2009.

The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million, including the lending commitment of LBCB, which also expires on November 6, 2010. There were $315 million of short-term borrowings outstanding under that facility at December 31, 2008. We had approximately $1 million of borrowing availability on this facility as of February 25, 2009, excluding the remaining unfunded commitment of LBCB. NU also had approximately $466 million of externally invested cash at February 25, 2009.

The lenders under these facilities are: Bank of America, N.A.; Barclays Bank PLC; BNY Mellon, N.A.; Citigroup Inc.; HSBC Bank USA, N.A.; JPMorgan Chase Bank, N.A.; LBCB; Sumitomo Mitsui Banking Corporation (Sumitomo); Toronto Dominion (Texas) LLC; Union Bank of California, N.A.; Wachovia Bank, N.A.; and Wells Fargo Bank, N.A. Lehman Brothers Holdings Inc., the parent of LBCB, filed for Chapter 11 bankruptcy protection in September 2008. LBCB's original aggregate lending commitment under the two facilities was $85 million, of which $30 million was assigned to Sumitomo in late September 2008. At December 31, 2008, LBCB had advanced approximately $19.2 million under the facilities and had declined to fund the remainder of its commitment. As a result, when current loans from LBCB are repaid, we will be limited to an aggregate of $845 million of borrowing capacity under our credit facilities, which we believe will provide sufficient operating flexibility to maintain adequate amounts of liquidity.

PSNH has outstanding approximately $407 million of PCRBs, one series of which, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as the result of failed auctions due to general market concerns. The interest rate on these PCRBs has reset by formula under the applicable documents every 35 days and has been between 0.2 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for a current interest rate of 0.3 percent. We are not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents.

In addition, CL&P has approximately $423.9 million of PCRBs, one series of which, in the aggregate principal amount of $62 million, had a fixed interest rate for a five-year period that expired on September 30, 2008. CL&P chose to acquire these PCRBs on October 1, 2008 as a result of poor liquidity in the tax-exempt market. These PCRBs, which mature in 2031, have not been retired, and CL&P expects to remarket them when conditions in the market improve.

Under their revolving credit facility agreements, each of NU, CL&P, WMECO, PSNH and Yankee Gas must maintain a ratio of consolidated debt to total capitalization of no more than 65 percent. At December 31, 2008, NU, CL&P, WMECO, PSNH, and Yankee Gas were, and are expected to remain, in compliance with this ratio.

For more information regarding NU and its subsidiaries' financing, see "Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to the Consolidated Financial Statements and "Liquidity" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders of three inactive regional nuclear companies, Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective facilities and are now engaged in the long-term storage of their spent nuclear fuel. Each Yankee Company collects decommissioning and closure costs through wholesale FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, PSNH and WMECO. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The ownership percentages of CL&P, PSNH and WMECO in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	Total
Connecticut Yankee Atomic Power Company	34.5%	5.0%	9.5%	49.0%
Maine Yankee Atomic Power Company	12.0%	5.0%	3.0%	20.0%
Yankee Atomic Electric Company	24.5%	7.0%	7.0%	38.5%

Our share of the obligations to support the Yankee Companies under FERC-approved rules is the same as the ownership percentages above.

For more information regarding decommissioning and nuclear assets, see "Deferred Contractual Obligations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in this Annual Report on Form 10-K.

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including the FERC, the SEC, and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each of our companies operates, including the DPUC having jurisdiction over CL&P and Yankee Gas, the NHPUC having jurisdiction over PSNH, and the DPU having jurisdiction over WMECO.

Environmental Regulation

We are subject to various federal, state and local requirements with respect to water quality, air quality, toxic substances, hazardous waste and other environmental matters. Additionally, our major generation and transmission facilities may not be constructed or significantly modified without a review of the environmental impact of the proposed construction or modification by the applicable federal or state agencies. PSNH owns generation assets and plans to spend approximately $457 million to install a wet flue gas desulphurization system at Merrimack Station to reduce mercury emissions of its coal fired plants in compliance with current New Hampshire law. Compliance with additional increasingly stringent environmental laws and regulations, particularly air and water pollution control requirements, may limit operations or require further substantial investments in new equipment at existing facilities.

Water Quality Requirements

The federal Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the United States Environmental Protection Agency or state environmental agency specifying the allowable quantity and characteristics of its effluent. States may also require additional permits for discharges into state waters. We are in the process of obtaining or renewing all required NPDES or state discharge permits in effect for our facilities. Compliance with NPDES and state discharge permits has necessitated substantial expenditures and may require further significant expenditures, which are difficult to estimate, because of additional requirements or restrictions that could be imposed in the future.

Air Quality Requirements

The Clean Air Act Amendments of 1990 (CAAA), as well as state laws in Connecticut, Massachusetts and New Hampshire, impose stringent requirements on emissions of SO2 and nitrogen oxides (NOX) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Installation of continuous emissions monitors and expanded permitting provisions also are included.

In New Hampshire, the Multiple Pollutant Reduction Program capped NOX, SO2 and carbon dioxide (CO2) emissions for current compliance beginning in 2007. In addition, a 2006 New Hampshire law requires PSNH to install a wet flue gas desulphurization system, known as "scrubber" technology, to reduce mercury emissions of its coal fired plants by at least 80 percent (with the co-benefit of reductions in SO2 emissions as well). Wet scrubber technology will be installed at Merrimack Station in Bow, New Hampshire. PSNH currently anticipates that compliance with this law will cost approximately $457 million. PSNH began site work for this project in November 2008. The project is scheduled to be completed by the end of 2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO2 emissions from fossil fuel-fired electric generating plants. It is the first market-based, mandatory cap-and-trade program in the U.S. designed to reduce greenhouse gas emissions. Each of the participating states has regulations in place to cap and then reduce the amount of CO2 that power plants in their region are allowed to emit. Power sector CO2 emissions are capped at current levels through 2014. The cap will then be reduced by 2.5 percent in each of the four years 2015 through 2018, for a total reduction of 10 percent. RGGI is composed of individual CO2 budget trading programs in each of the participating states. Each participating state s CO2 budget trading program establishes its respective share of the regional cap, and each state will issue CO2 allowances in a number equivalent to its portion of the regional cap. Each CO2 allowance represents a permit to emit one ton of CO2 in a specific year. The RGGI states will distribute CO2 allowances primarily through regional auctions.

Because CO2 allowances issued by any participating state will be usable across all state programs, the ten individual state CO2 budget trading programs, in the aggregate, will form one regional compliance market for CO2 emissions. Initial CO2 allowance auctions were held in 2008 as pre-compliance events to facilitate market price discovery and compliance planning by regulated CO2 emitters. A regulated power plant must hold CO2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period beginning in 2009.

Connecticut adopted regulations in connection with RGGI in July 2008 which established an auction clearing price threshold of $5 per CO2 allowance, above which all auction proceeds will be rebated to customers. For proceeds up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed by the state s utilities in conjunction with the Energy Conservation Management Board. Seventy-five percent of the RGGI auction proceeds directed to conservation and load management programs will be allocated to CL&P s programs. Because CL&P does not own any generating assets, it is not required to acquire CO2 allowances; however, the costs will likely be included in wholesale rates charged to CL&P in standard offer type contracts.

Massachusetts law does not set an auction clearing price threshold for RGGI auctions. The law requires 80 percent of RGGI auction proceeds to be allocated to utility energy efficiency and demand response programs. Because WMECO does not own any generation assets, it is not required to acquire any CO2 allowances; however, the costs will likely be included in wholesale rates charged to WMECO in standard offer type contracts.

New Hampshire law sets an auction clearing price threshold of $6 per CO2 allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO2 per year after taking into effect the operation of PSNH s Northern Woods wood-burning generating plant that, under the RGGI formula, decreased PSNH s responsibility for reducing fossil-fired CO2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO2 allowances per year for PSNH s fossil fueled generating plants during the 2009-2011 compliance period. These banked CO2 allowances will initially comprise approximately one-half of the yearly CO2 allowances required for PSNH s generating plants to comply with RGGI and such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing CO2 allowances at auction or in the secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers.

The first regional auction of RGGI CO2 allowances took place on September 25, 2008. Six states offered allowances for sale. At the auction, more than 12.5 million CO2 allowances were sold at the clearing price of $3.07 per CO2 allowance. The auction raised $38.6 million for use by the six RGGI states. The next regional auction took place on December 17, 2008. All ten RGGI states participated and more than 31.5 million CO2 allowances were sold at a clearing price of $3.38 per allowance. The auction raised $106.5 million for use by the ten RGGI states. For 2009, four quarterly regional auctions are scheduled for March, June, September and December.

Each of the states in which we do business also has renewable portfolio standards (RPS). New Hampshire s renewable portfolio standards provision requires increasing percentages of the electricity sold to retail customers in the state, beginning in 2008, to have direct ties to renewable sources, ultimately reaching 23.8 percent by 2025. PSNH is required to comply with these standards. We expect that the additional costs incurred to meet this new requirement will be recovered through PSNH s energy service rates. Connecticut's RPS statutes require that a specific percentage of the generation provided to Connecticut consumers be produced from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources. Beginning with a 4 percent requirement in 2004, the requirement increases each year. For 2009, the requirement is 12 percent, increasing to 14 percent by 2010, 19.5 percent by 2015 and 27 percent by 2020. Massachusetts RPS program required electricity suppliers to meet a 1 percent renewable energy standard in 2003, which increased to 4 percent for 2009 and has a goal of 15 percent by 2015.

In addition, many states and environmental groups have challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. As a result, it is possible that state and federal regulations could be developed that will impose more stringent limitations on emissions than are currently in effect.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, residues from operations were often disposed of by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, ash, gasoline and other hazardous materials that might contain polychlorinated biphenyls. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. We have recorded a liability for what we believe is, based upon currently available information, our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability, and continue to evaluate the environmental impact of our former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on us for such past disposal. At December 31, 2008, the liability recorded by us for our estimable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $27.4 million, representing 54 liabilities. All cost estimates were made in accordance with generally accepted accounting principles where investigation and/or remediation costs are probable and reasonably estimable. These costs could be significantly higher if additional remedial actions become necessary or when additional information as to the extent of contamination becomes available.

The most significant liabilities currently relate to future clean up costs at former manufactured gas plant (MGP) facilities. These facilities were owned and operated by predecessor companies to us from the mid-1800's to mid-1900's. By-products from the manufacture of gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose risks to human health and the environment. We, through our subsidiaries, currently have partial or full ownership responsibilities at 28 former MGP sites. Of our total recorded liabilities of $27.4 million, a reserve of approximately $25.4 million has been established to address future investigation and/or remediation costs at MGP sites. In addition, Holyoke Water Power Company (HWP), a wholly-owned subsidiary of NU, is continuing to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a MGP, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP and HG&E share responsibility for the site. HWP has already conducted substantial investigative and remediation activities.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP s 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. HWP has developed and begun to implement plans for

16

additional investigations in conformity with MA DEP s guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

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

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

For further information on environmental liabilities, see Note 7B, "Commitments and Contingencies - Environmental Matters" to the Consolidated Financial Statements contained in this Annual Report on Form 10-K.

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Although weak health risk associations reported in some epidemiology studies remain unexplained, most researchers, as well as numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies, have concluded that the available body of scientific information does not support the conclusion that EMF affects human health.

We have closely monitored research and government policy developments for many years and will continue to do so. In accordance with recommendations of various regulatory bodies and public health organizations, we reduce EMF associated with new transmission lines by the use of designs that can be implemented without additional cost or at a modest cost. We do not believe that other capital expenditures are appropriate to minimize unsubstantiated risks.

FERC Hydroelectric Project Licensing

New Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, or (ii) the United States may take over the project or (iii) the FERC may issue a new license to a new licensee, upon payment to the existing licensee of the lesser of the fair value or the net investment in the project, plus severance damages, less certain amounts earned by the licensee in excess of a reasonable rate of return.

PSNH owns nine hydroelectric generating stations with an aggregate of approximately 66.3 MW of capacity, with a current claimed capability representing winter rates, of approximately 69.5 MW. Of these nine plants, eight are licensed by the FERC under long-term licenses that expire on varying dates from 2009 through 2036. As a licensee under the Federal Power Act (FPA), PSNH and its licensed hydroelectric projects are subject to conditions set forth in the FPA and related FERC regulations, including provisions related to the condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment and severance damages and other matters.

FERC hydroelectric project licenses expire periodically, and the generating facilities must be relicensed at such times. A new FERC license for PSNH s Merrimack River Hydroelectric Project, which consists of the Amoskeag, Hooksett and Garvins Falls generating stations, was issued on May 18, 2007. PSNH's Canaan Hydroelectric Project is currently undergoing relicensing proceedings. On January 16, 2009, FERC issued a new license for this project. The new license takes effect upon the July 3, 2009 expiration of its current license. The water quality certification associated with this new license has been appealed to the Vermont Environmental Court.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision which expressly permits the FERC to order decommissioning during the license term. However, the FERC has taken the position that under appropriate circumstances it may order decommissioning of hydroelectric projects at relicensing or may require the establishment of decommissioning trust funds as a condition of relicensing. The FERC may also require project decommissioning during a license term if a hydroelectric project is abandoned, the project license is surrendered or the license is revoked.

At this time, it appears unlikely that the FERC will order decommissioning of PSNH's hydroelectric projects at relicensing or that the projects will be abandoned, surrendered or the project licenses revoked. However, it is impossible to predict the outcome of the FERC relicensing proceedings with certainty, or to determine the impact of future regulatory actions on project economics. Until such time as a project is ordered to be decommissioned and the terms and conditions of a decommissioning order are known, any estimates of the cost of project decommissioning are preliminary and subject to change as new information becomes available.

EMPLOYEES

As of December 31, 2008, we employed a total of 6,189 employees, excluding temporary employees, of which 1,944 were employed by CL&P, 1,268 by PSNH, 366 by WMECO, 417 by Yankee Gas and 2,182 were employed by Northeast Utilities Service Company (NUSCO). Approximately 2,300 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are covered by 11 union agreements.

INTERNET INFORMATION

Our website address is www.nu.com. We make available through our website a link to the SEC's IDEA site, at which site NU's, CL&P's, WMECO's and PSNH's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports may be reviewed. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Northeast Utilities, 107 Selden Street, Berlin, Connecticut 06037.

Item 1A.

Risk Factors

We are subject to a variety of significant risks in addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" in Item 1, "Business," above. Our susceptibility to certain risks, including those discussed in detail below, could exacerbate other risks. These risk factors should be considered carefully in evaluating our risk profile.

The infrastructure of our transmission and distribution system may not operate as expected, and could require additional unplanned expense which could adversely affect our earnings.

Our ability to manage operational risk with respect to our transmission and distribution systems is critical to the financial performance of our business. Our transmission and distribution businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age), accidents and labor disputes. The costs (both labor and material) that our regulated companies incur to construct and maintain their electric delivery systems have increased in recent years. These increases have been driven primarily by higher demand for commodities and electrical products, as well as increased demand for skilled labor. A significant percentage of our regulated company equipment is nearing or at the end of its life cycle, such as old and obsolete distribution poles, underground primary cables and substation switchgear. The failure of our transmission and distributions systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in expenses, including higher maintenance costs. Any such costs which may not be recoverable from our ratepayers would have an adverse effect on our earnings.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition. The extreme disruption in the capital markets has limited companies ability to access the capital and credit markets to support their operations and refinance debt and has led to higher financing costs compared to recent years. We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not satisfied by our operating cash flow, including construction costs. The cost of debt financing and the proceeds of equity financing may be materially adversely impacted by these market conditions. The inability to raise capital on favorable terms could negatively affect our ability to maintain and to expand our businesses. Our current credit ratings cause us to believe that we will continue to have access to the capital markets. However, events beyond our control, such as the disruption in global capital and credit markets in 2008, may create uncertainty that could increase our cost of capital or impair our ability to access the capital markets. In addition, certain of NU parent s subsidiaries rely, in part, on NU parent for access to capital. Circumstances that limit NU parent s access to capital could impair its ability to provide those companies with needed capital. The credit crisis could also have an impact on our lenders or our customers, causing them to fail to meet their obligations to us. Additionally, the crisis could have a broader impact on business in general in ways that could lead to reduced electricity and gas usage, which could have a negative impact on our revenues.

In addition, the consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses.

Changes in regulatory or legislative policy, difficulties in obtaining siting, design or other approvals, global demand for critical resources, or environmental or other concerns, or construction of new generation may delay completion of or displace our transmission projects or adversely affect our ability to recover our investments or result in lower than expected rates of return.

The successful implementation of our transmission construction plans is subject to the risk that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could impact our ability to meet our construction schedule and/or require us to incur additional expenses and may adversely affect our ability to achieve forecast levels of revenues. In addition, difficulties in obtaining required approvals for construction, or increased cost of and difficulty in obtaining critical resources as a result of global or domestic demand for such resources could cause delays in our construction schedule and may adversely affect our ability to achieve forecasted earnings.

The regulatory approval process for our planned transmission projects encompasses an extensive permitting, design and technical approval process. Various factors could result in increased cost estimates and delayed construction. These include environmental and community concerns and design and siting issues. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all such expenses have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, to the extent that new generation facilities are proposed or built to address the region s energy needs, the need for our planned transmission projects may be delayed or displaced, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

The currently planned transmission projects are expected to help alleviate identified reliability issues and to help reduce customers' costs. However, if, due to further regulatory or other delays, the projected in-service date for one or more of these projects is delayed, there may be increased risk of failures in the existing electricity transmission system and supply interruptions or blackouts may occur which could have an adverse effect on our earnings.

The FERC has followed a policy of providing incentives designed to encourage the construction of new transmission facilities, including higher returns on equity and allowing facilities under construction to be placed in rate base before completion. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the level presently anticipated.

Increases in electric and gas prices, the continued economic slowdown and focus on conservation and self-generation by customers and changes in legislative and regulatory policy may adversely impact our business.

The nation's economy has been affected by significant increases in energy prices, particularly fossil fuels, as well as by a general economic slowdown. The impact of these increases has led to increased electricity and natural gas prices for our customers, which, coupled with the continued economic slowdown, has increased the focus on conservation, energy efficiency and self-generation on the part of customers and on legislative and regulatory policies. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity and gas sales in our service territories. If any such declines were to occur without corresponding adjustments in rates, then our revenues would be reduced and our future growth prospects would be limited.

In addition, Connecticut, New Hampshire and Massachusetts have each announced policies aimed at increased energy efficiency and conservation. In connection with such policies, all three states have opened proceedings to investigate revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. In Connecticut, the DPUC authorized decoupling via a rate design that is intended to recover proportionately greater distribution revenue through the fixed Customer and Demand charges, and proportionately less distribution revenue through the per kWh charges . At this time it is uncertain what mechanisms will ultimately be adopted by New Hampshire and Massachusetts and what impact these decoupling mechanisms will have on our companies.

Changes in regulatory policy may adversely affect our transmission franchise rights or facilitate competition for construction of large-scale transmission projects, which could adversely affect our earnings.

We have undertaken a substantial transmission capital investment program and expect to invest approximately $3.5 billion in regulated electric transmission infrastructure from 2009 through 2013.

Although our public utility subsidiaries have exclusive franchise rights for transmission facilities in our service area, the demand for improved transmission reliability could result in changes in federal or state regulatory or legislative policy that could cause us to lose the exclusivity of our franchises or allow other companies to compete with us for transmission construction opportunities. Such a change in policy could result in reduced transmission capital investments, reduce earnings, and limit future growth prospects.

Changes in regulatory and/or legislative policy could negatively impact regional transmission cost allocation rules.

The existing New England transmission tariff allocates the costs of transmission investment that provide regional benefits to all customers in New England. As new investment in regional transmission infrastructure occurs in any one state, there is a sharing of these regional costs across all of New England. This regional cost allocation is contractually agreed to by the Transmission Operating Agreement signed by all of the New England transmission owning utilities but can be changed with the approval of a majority of the transmission owning utilities after February 1, 2010. In addition, after that date, other parties, such as state regulators, may seek certain changes to the regional cost allocation, which could have adverse effects on our distribution companies' local rates. We are working to retain the existing regional cost allocation treatment but cannot predict the actions of the states or utilities in the region.

Changes in regulatory or legislative policy could jeopardize our full recovery of costs incurred by our distribution companies.

Under state law, our utility companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their reasonable operating and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Each of these companies prepares and submits periodic rate filings with their respective state regulatory commissions for review and approval. There is no assurance that these state commissions will approve the recovery of all costs prudently incurred by our regulated companies, such as for operation and maintenance, construction, as well as a return on investment on their respective regulated assets. Increases in these costs, coupled with increases in fuel and energy prices could lead to consumer or regulatory resistance to the timely recovery of such prudently incurred costs, thereby adversely affecting our cash flows and results of operations.

In addition, CL&P and WMECO procure energy for a substantial portion of their customers via requests for proposal on an annual, semi-annual or quarterly basis. CL&P and WMECO receive approvals of recovery of these contract prices from the DPUC and DPU, respectively. While both regulatory agencies have consistently approved solicitation processes, results and recovery of costs, management cannot predict the outcome of future solicitation efforts or the regulatory proceedings related thereto.

The energy requirements for PSNH are currently met primarily through PSNH's generation resources or fixed-price forward purchase contracts. PSNH s remaining energy needs are met primarily through spot market or bilateral energy purchases. Unplanned forced outages of its generating plants could increase the level of energy purchases needed by PSNH and therefore increase the market risk associated with procuring the necessary amount of energy to meet requirements. PSNH recovers these costs through its ES rate, subject to a prudence review by the NHPUC. We cannot predict the outcome of future regulatory proceedings related to recovery of these costs.

Judicial or regulatory proceedings or changes in regulatory or legislative policy could jeopardize completion of, or full recovery of costs incurred by PSNH in constructing, the Clean Air Project.

Pursuant to New Hampshire law, PSNH has begun work on the Clean Air Project at its Merrimack Station in Bow, New Hampshire. As a result of an increase in the estimated cost of the project from $250 million to $457 million, several parties have initiated legal proceedings challenging the project. These proceedings, or new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could result in the delay or cancelation of this project or add to its cost. Any delay or cancelation of the project would adversely affect our ability to achieve forecast levels of earnings. If the project were to be canceled, contract payments and termination costs would be a substantial portion of the contractual commitments entered into by PSNH. As of March 31, 2009, the contractual commitments are expected to total approximately $250 million. The actual amount of contract termination costs would depend on timing of the cancelation and negotiations with the contractors. At this time, we cannot predict any legislative or regulatory changes or the outcome of the pending legal proceedings.

In addition, PSNH s investment in the project after it is completed is subject to prudence review by the NHPUC at the time the project is placed in service. A prudence disallowance of a material nature could adversely affect PSNH s cash flows and results of operations. While we believe that all expenditures to date have been prudently incurred, we cannot predict the outcome of any prudency reviews should they occur. Our projected earnings and growth could be adversely affected were the NHPUC to deny recovery of some or all of PSNH s investment in the project.

The loss of key personnel or the inability to hire and retain qualified employees could have an adverse effect on our business, financial condition and results of operations.

Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. We cannot guarantee that any member of our management or any key employee at the NU parent or subsidiary level will continue to serve in any capacity for any particular period of time. In addition, a significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to ten years. Such highly skilled individuals cannot be quickly replaced due to the technically complex work they perform. We are developing strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce, but cannot predict the impact of these plans on our ability to hire and retain key employees.

Grid disturbances, severe weather, or acts of war or terrorism could negatively impact our business.

Because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business continuity due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage, or terrorist action) on an interconnected system or the actions of another utility. In addition, we are subject to the risk that acts of war or terrorism could negatively impact the operation of our system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

Severe weather, such as ice and snow storms, such as the ice storm that impacted New Hampshire in December 2008, hurricanes and other natural disasters, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial. The effect of the failure of our facilities to operate as planned would be particularly burdensome during a peak demand period, such as during the hot summer months.

A negative change in NU's credit ratings could require NU parent to post cash collateral and affect our ability to obtain financing.

NU parent s senior unsecured debt ratings by Moody's Investors Service, Standard & Poor's, Inc. and Fitch Ratings are currently Baa2, BBB- and BBB, respectively, with stable outlooks. Were any of these ratings to decline to non-investment grade level, Select Energy could be asked to provide, as of December 31, 2008, collateral in the form of cash or letters of credit in the amount of $23.2 million to unaffiliated counterparties and cash or letters of credit in the amount of $10 million to two independent system operators. While our credit facilities are sufficient in amounts that would be adequate to meet collateral calls at that level, our ability to meet any future collateral calls would depend on our liquidity and access to bank lines and the capital markets at such time.

Changes in wholesale electric sales could require Select Energy to acquire or sell additional electricity on unfavorable terms.

Select Energy's remaining wholesale sales contracts provide electricity to full requirements customers, including a municipal electric company. Select Energy provides a portion of the customer's electricity requirements. The volumes sold under these contracts vary based on the usage of the underlying retail electric customers, and usage is dependent upon factors outside of Select Energy's control, such as economic activity and weather. The varying sales volumes may differ from the supply volumes that Select Energy expected to utilize from electricity purchase contracts. Differences between actual sales volumes and supply volumes may require Select Energy to purchase additional electricity or sell excess electricity, both of which are subject to market conditions which change due to weather, plant availability, transmission congestion, and input fuel costs. The purchase of additional electricity at high prices or sale of excess electricity at low prices could negatively impact Select Energy's cost to serve the contracts.

Costs of compliance with environmental regulations may increase and have an adverse effect on our business and results of operations.

Our subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations which regulate, among other things, air emissions, water discharges and the management of hazardous and solid waste. Compliance with these requirements requires us to incur significant costs relating to environmental monitoring, installation of pollution control equipment, emission fees, maintenance and upgrading of facilities, remediation and permitting. The costs of compliance with existing legal requirements or legal requirements not yet adopted may increase in the future. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and results of operations, financial position and cash flows.

In addition, global climate change issues have received an increased focus on the federal and state government levels which could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the power plants we own and operate as well as general utility operations. Although we would expect that any costs of these rules and regulations would be recovered from ratepayers, the impact of these rules and regulations on energy use by ratepayers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time.

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control, or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. Revised or additional laws could result in significant additional expense and operating restrictions on our facilities or increased compliance costs which may not be fully recoverable in distribution company rates for generation. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time. For further information, see Item 1, "Business - Other Regulatory and Environmental Matters - Environmental Regulation" in this Annual Report on Form 10-K.

We are subject to legal proceedings which could result in large cash obligations.

We are engaged in legal proceedings that could result in the imposition of large cash obligations against us. We may also be subject to future legal proceedings based on asserted or unasserted claims and cannot predict the outcome of any of these proceedings. Adverse outcomes in existing or future legal proceedings could result in the imposition of substantial cash damage awards or cash obligations against us.

Further information regarding legal proceedings, as well as other matters, is set forth in Item 3, "Legal Proceedings."

Item 1B.

Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2.

Properties

Transmission and Distribution System

At December 31, 2008, our electric operating subsidiaries owned 29 transmission and 443 distribution substations that had an aggregate transformer capacity of 4,312,000 kilovolt amperes (kVa) and 29,401,000 kVa, respectively; 3,096 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 432 cable miles of underground transmission lines ranging from 69 KV to 345

KV; 34,897 pole miles of overhead and 2,925 conduit bank miles of underground distribution lines; and 536,203 underground and overhead line transformers in service with an aggregate capacity of 36,730,940 kVa.

Electric Generating Plants

As of December 31, 2008, PSNH owned the following electric generating plants:

Type of Plant	Number of Units	Year Installed	Claimed Capability* (kilowatts)
Total - Fossil-Steam Plants	(7 units)	1952-78	997,532
Total - Hydro-Conventional	(20 units)	1917-83	70,329
Total - Internal Combustion	(5 units)	1968-70	102,961
Total PSNH Generating Plant	(32 units)		1,170,822

*Claimed capability represents winter ratings as of December 31, 2008. The nameplate capacity of the generating plants is approximately 1,200 MW.

Neither CL&P nor WMECO owned any electric generating plants during 2008.

Yankee Gas

At December 31, 2008, Yankee Gas owned 27 gate stations, approximately 270 district regulator stations and 3,200 miles of main gas pipelines. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut as well as propane facilities in Danbury, Kensington and Vernon, Connecticut.

Franchises

CL&P. Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to provide electric transmission and distribution services in the respective areas in which it is now supplying such service.

In addition to the right to provide electric transmission and distribution services as set forth above, the franchises of CL&P include, among others, limited rights and powers, as set forth in Title 16 of the Connecticut General Statutes and the special acts of the General Assembly constituting its charter, to manufacture, generate, purchase and/or sell electricity at retail, including to provide Standard Service, Supplier of Last Resort service and backup service, to sell electricity at wholesale and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain. Title 16 of the Connecticut General Statutes was amended by Public Act 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," to prohibit an electric distribution company from owning or operating generation assets. However, Public Act 05-01, "An Act Concerning Energy Independence," allows CL&P to own up to 200 MW of peaking facilities if the DPUC determines that such facilities will be more cost effective than other options for mitigating FMCCs and LICAP costs. In addition, Section 83 of Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency" states that if an existing electric generating plant located in Connecticut is offered for sale, then an electric distribution company, such as CL&P, would be eligible to purchase the generation plant upon obtaining prior approval from the DPUC and a determination by the DPUC that such purchase is in the public interest.

PSNH. The NHPUC, pursuant to statutory requirements, has issued orders granting PSNH exclusive franchises to distribute electricity in the respective areas in which it is now supplying such service.

In addition to the right to distribute electricity as set forth above, the franchises of PSNH include, among others, rights and powers to manufacture, generate, purchase, and transmit electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The distribution and transmission franchises of PSNH include the power of eminent domain.

WMECO. WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and for extensions of lines in public highways. Further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority and pursuant to state laws, has the power of eminent domain. On December 31, 2008, WMECO purchased all of the transmission-related assets of its affiliates, HWP and HP&E, for approximately $4 million.

The Massachusetts restructuring legislation defines service territories as those territories actually served on July 1, 1997 and following municipal boundaries to the extent possible. The restructuring legislation further provides that until terminated by law or otherwise, distribution companies shall have the exclusive obligation to serve all retail customers within their service territories and no other person shall provide distribution service within such service territories without the written consent of such distribution companies. Pursuant to the Massachusetts restructuring legislation, the DPU (then, the Department of Telecommunications and Energy) was required to define service territories for each distribution company, including WMECO. The DPU subsequently determined that there were advantages to the exclusivity of service territories and issued a report to the Massachusetts Legislature recommending against, in this regard, any changes to the restructuring legislation.

Holyoke Water and Power Company and Holyoke Power and Electric Company. HWP, and its wholly owned subsidiary HP&E, are authorized by their charters to conduct their businesses in the territories served by them. In connection with the sale of certain of HWP's and HP&E's assets to the city of Holyoke Gas and Electric Department (HG&E) effective December 2001, HWP agreed not to distribute electricity at retail in Holyoke and surrounding towns unless other sellers can legally compete with HG&E, and to amend the charters of HWP and HP&E to reflect that limitation.

Prior to December 31, 2008, the two companies had locations in the public highways for their transmission lines. Such locations were granted pursuant to the laws of Massachusetts by the Massachusetts Department of Public Works or by local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. HP&E has no retail service territory area and sells electric power exclusively at wholesale. On December 31, 2008, HWP and HP&E sold all of their transmission-related assets to WMECO.

Yankee Gas. Yankee Gas directly and from its predecessors in interest holds valid franchises to sell gas in the areas in which Yankee Gas supplies gas service. Generally, Yankee Gas holds franchises to serve customers in areas designated by those franchises as well as in most other areas throughout Connecticut so long as those areas are not occupied and served by another gas utility under a valid franchise of its own or are not subject to an exclusive franchise of another gas utility. Yankee Gas s franchises are perpetual but remain subject to the power of alteration, amendment or repeal by the General Assembly of the State of Connecticut, the power of revocation by the DPUC and certain approvals, permits and consents of public authorities and others prescribed by statute. Generally, Yankee Gas s franchises include, among other rights and powers, the right and power to manufacture, generate, purchase, transmit and distribute gas and to erect and maintain certain facilities on public highways and grounds, and the right of eminent domain, all subject to such consents and approvals of public authorities and others as may be required by law.

Item 3.

Legal Proceedings

1.

Yankee Companies v. U.S. Department of Energy

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

In a ruling released in 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. CL&P, PSNH and WMECO expect to pass any recovery onto their customers, therefore, no earnings impact is expected to result. In December 2006, the DOE appealed the decision and the Yankee Companies filed cross-appeals. The Court of Appeals disagreed with the trial court s method of calculation of the amount of the DOE s liability, among other things, and vacated the decision of the Court of Federal Claims and remanded the case to make new findings consistent with its decision. The application of any damages which are ultimately recovered to benefit customers is established in the Yankee Companies' FERC-approved rate settlement agreements, although implementation will be subject to the final determination of the FERC.

In December 2007, the Yankee Companies filed a second round of lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001 and 2002.

2.

Connecticut MGP Cost Recovery

On August 5, 2004, Yankee Gas and CL&P (NU Companies) demanded contribution from UGI Utilities, Inc. (UGI) of Pennsylvania for past and future remediation costs related to historic MGP operations on thirteen sites currently or formerly owned by the NU Companies (Yankee Gas is responsible for ten of the sites, CL&P for two of the sites, and both companies share responsibility for one site) in a number of different locations throughout the State of Connecticut. The NU Companies alleged that UGI controlled operations of the plants at various times throughout the period 1883 to 1941, when UGI was forced to divest its interests. Investigations and remediation expenditures at the sites to date total over $20 million, and projected potential remediation costs for all sites, based on litigation modeling assumptions, could total as much as $232 million. At this point, we are unable to estimate the potential costs associated with this matter.

In September 2006, the NU Companies filed a complaint against UGI in the U.S. District Court for the District of Connecticut seeking a fair and equitable contribution for the actual and anticipated remediation costs related to the former MGP operations. The trial has been scheduled for April 2009.

3.

Other Legal Proceedings

For further discussion of legal proceedings see the following sections of Item 1, "Business": "Regulated Electric Distribution," "Regulated Gas Operations," and "Regulated Electric Transmission" for information about various state regulatory and rate proceedings, civil lawsuits related thereto, and information about proceedings relating to power, transmission and pricing issues; "Nuclear Decommissioning" for information related to high-level nuclear waste; and "Other Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality requirements, toxic substances and hazardous waste, EMF, licensing of hydroelectric projects, and other matters. In addition, see Item 1A, "Risk Factors" for general information about several significant risks.

Item 4.

Submission Of Matters To a Vote of Security Holders

No event that would be described in response to this item occurred with respect to NU or CL&P.

The information called for by Item 4 is omitted for PSNH and WMECO pursuant to General Instruction I (2)(c) of Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries.)

EXECUTIVE OFFICERS OF THE REGISTRANT

This information is provided by NU in reliance on General Instruction G of Form 10-K. All of the Company s officers serve terms of one year and until their successors are elected and qualified:

Name	Age	Title
Gregory B. Butler	51	Senior Vice President and General Counsel.
Peter J. Clarke	47	President and Chief Operating Officer and a Director of WMECO. Previously Vice President - Shared Services of Northeast Utilities Service Company (NUSCO), a subsidiary of NU.
Jean M. LaVecchia	57	Vice President - Human Resources of NUSCO.
David R. McHale	48	Executive Vice President and Chief Financial Officer.
Leon J. Olivier	60	Executive Vice President and Chief Operating Officer.
Shirley M. Payne*	57	Vice President - Accounting and Controller.
James B. Robb	48	Senior Vice President, Enterprise Planning and Development of NUSCO.
Charles W. Shivery	63	Chairman of the Board, President and Chief Executive Officer.

*

On February 17, 2009, Ms. Payne resigned her position and was appointed Vice President - Shared Services of NUSCO, in each case, effective April 1, 2009.

Gregory B. Butler. Mr. Butler became Senior Vice President and General Counsel of NU effective December 1, 2005, and of CL&P, PSNH and WMECO, subsidiaries of NU, effective March 9, 2006, and was elected a Director of Northeast Utilities Foundation, Inc. effective December 1, 2002. Previously Mr. Butler served as Senior Vice President, Secretary and General Counsel of NU from August 31, 2003 to December 1, 2005 and Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003.

Peter J. Clarke. Mr. Clarke was elected President and Chief Operating Officer and a Director of WMECO, and a Director of Northeast Utilities Foundation, Inc., effective January 1, 2009. Previously, Mr. Clarke served as Vice President - Shared Services of NUSCO, CL&P, PSNH and WMECO, from January 1, 2008 to December 31, 2008; Vice President - Customer Operations of CL&P from July 1, 2006 to December 31, 2007; Vice President - Customer Operations and Relations of CL&P from January 17, 2005 to June 30, 2006; and Director - System Projects of CL&P from March 11, 2002 to January 16, 2005.

Jean M. LaVecchia. Ms. LaVecchia was elected Vice President - Human Resources of NUSCO, effective January 1, 2005 and was elected a Director of Northeast Utilities Foundation, Inc. effective January 30, 2007. Previously, Ms. LaVecchia served as Vice President - Human Resources and Environmental Services from May 1, 2001 to December 31, 2004.

David R. McHale. Mr. McHale was elected Executive Vice President and Chief Financial Officer of NU, CL&P, WMECO and PSNH, effective January 1, 2009, elected a Director of PSNH and WMECO, effective January 1, 2005, of CL&P effective January 15, 2007 and of Northeast Utilities Foundation, Inc. effective January 1, 2005. Previously, Mr. McHale served as Senior Vice President and Chief Financial Officer of NU, CL&P, PSNH and WMECO from January 1, 2005 to December 31, 2008 and Vice President and Treasurer of NU, WMECO and PSNH from July 1998 to December 31, 2004.

Leon J. Olivier. Mr. Olivier was elected Executive Vice President and Chief Operating Officer of NU effective May 13, 2008; He also has served as Chief Executive Officer of CL&P, PSNH and WMECO since January 15, 2007; a Director of PSNH and WMECO since January17, 2005 and a Director of CL&P since September 2001. Previously, Mr. Olivier served as Executive Vice President - Operations of NU from February 13, 2007 to May 12, 2008 Executive Vice President of NU from December 1, 2005 to February 13, 2007; President - Transmission Group of NU from January 17, 2005 to December 1, 2005; and President and Chief Operating Officer of CL&P from September 2001 to January 2005.

Shirley M. Payne. Ms. Payne was elected Vice President - Accounting and Controller of NU effective February 13, 2007, and Vice President - Accounting and Controller of CL&P, PSNH and WMECO effective January 29, 2007. Previously, Ms. Payne served as Vice President, Corporate Accounting and Tax of TECO Energy, Inc., from July 2000 to January 26, 2007, and Tax Officer of TECO Energy, Inc., from April 1999 to January 26, 2007.

James B. Robb. Mr. Robb was elected Senior Vice President, Enterprise Planning and Development of NUSCO on September 4, 2007. Previously, Mr. Robb served as Managing Director, Russell Reynolds Associates from December 2006 to August 2007; Entrepreneur in Residence, Mohr Davidow Ventures from March 2006 to November 2006; Senior Vice President, Retail Marketing, Reliant Energy, Inc. from December 2003 to December 2006; and Senior Vice President, Performance Management, Reliant Resources, Inc. from November 2002 to December 2003.

Charles W. Shivery. Mr. Shivery was elected Chairman of the Board, President and Chief Executive Officer of NU effective March 29, 2004; Chairman and a Director of CL&P, PSNH and WMECO effective January 19, 2007 and a Director of Northeast Utilities Foundation effective March 3, 2004. Previously, Mr. Shivery served as President (interim) of NU from January 1, 2004 to March 29, 2004; and President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 2003.

There are no family relationships between any executive officer and any Trustee or other executive officer of NU and none of the above executive officers serve as an executive officer pursuant to any agreement or understanding with any other person.

Part II

Item 5.

Market for The Registrants' Common Equity and Related Stockholder Matters

NU. Our common shares are listed on the New York Stock Exchange. The ticker symbol is "NU," although it is frequently presented as "Noeast Util" and/or "NE Util" in various financial publications. The high and low closing sales prices for the past two years, by quarters, are shown below.

Year	Quarter	High	Low
2008	First	$ 31.15	$ 24.01
	Second	27.74	25.12
	Third	28.03	24.52
	Fourth	25.97	19.15
2007	First	$ 32.77	$ 27.40
	Second	33.53	27.37
	Third	29.42	26.93
	Fourth	32.83	27.98

There were no purchases made by or on behalf of our company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of common stock during the fourth quarter of the year ended December 31, 2008.

As of January 31, 2009, there were 44,042 common shareholders of our company on record. As of the same date, there were a total of 176,230,893 common shares issued, including 643,860 unallocated Employee Stock Ownership Plan (ESOP) shares held in the ESOP trust.

Pursuant to NU parent's Shareholder Rights Plan (the "Plan"), NU parent distributed to shareholders of record as of May 7, 1999, a dividend in the form of one common share purchase right (a "Right") for each common share owned by the shareholder. The Rights and the Plan expired at the end of the 10-year term on February 23, 2009. NU parent's Board of Trustees adopted the Plan in 1999 to protect its shareholders in the event of an unsolicited bid to acquire the company. If triggered, it would have allowed shareholders other than the acquiror to purchase a specified number of additional shares at a 50 percent discount from the then current market price, thus encouraging the acquiror to negotiate a fair price for NU common shares with the Board. NU parent s Board of Trustees felt that renewal of the Plan was unnecessary at this time to protect shareholders' rights and accordingly decided to allow it to expire. The Board has the ability in its discretion to adopt a similar plan in the future but has no present intention of doing so.

On February 10, 2009, our Board of Trustees declared a dividend of 23.75 cents per share, payable on March 31, 2009, to shareholders of record as of March 1, 2009.

On October 14, 2008, our Board of Trustees declared a dividend of 21.25 cents per share, payable on December 31, 2008, to shareholders of record as of December 1, 2008.

On May 12, 2008, our Board of Trustees declared a dividend of 21.25 cents per share, payable on September 30, 2008, to shareholders of record as of September 1, 2008.

On April 8, 2008, our Board of Trustees declared a dividend of 20 cents per share, payable on June 30, 2008, to shareholders of record as of June 1, 2008.

On February 12, 2008, our Board of Trustees declared a dividend of 20 cents per share, payable on March 31, 2008, to shareholders of record as of March 1, 2008.

On November 13, 2007, our Board of Trustees declared a dividend of 20 cents per share, payable on December 31, 2007, to shareholders of record as of December 1, 2007.

On May 7, 2007, our Board of Trustees declared a dividend of 20 cents per share, payable on September 28, 2007, to shareholders of record as of September 1, 2007.

On April 10, 2007, our Board of Trustees declared a dividend of 18.75 cents per share, payable on June 29, 2007, to shareholders of record as of June 1, 2007.

On February 13, 2007, our Board of Trustees declared a dividend of 18.75 cents per share, payable on March 31, 2007, to shareholders of record as of March 1, 2007.

Information with respect to dividend restrictions for us, CL&P, PSNH, and WMECO is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity" and in the "Combined Notes to Consolidated Financial Statements," within this Annual Report on Form 10-K.

There is no established public trading market for the common stock of CL&P, PSNH and WMECO. All of the common stock of CL&P, PSNH and WMECO is held solely by NU.

During 2008 and 2007, CL&P approved and paid $106.5 million and $79.2 million, respectively, of common stock dividends to NU.

During 2008 and 2007, PSNH approved and paid $36.4 million and $30.7 million, respectively, of common stock dividends to NU.

During 2008 and 2007, WMECO approved and paid $39.7 million and $12.8 million, respectively, of common stock dividends to NU.

For information regarding securities authorized for issuance under equity compensation plans, see Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters," included in this Annual Report on Form 10-K.

Item 6.

Selected Financial Data

NU Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and share information)	2008	2007	2006	2005	2004
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 8,207,876	$ 7,229,945	$ 6,242,186	$ 6,417,230	$ 5,864,161
Total Assets	13,988,480	11,581,822	11,303,236	12,567,875	11,638,396
Total Capitalization (a)	7,293,960	6,667,920	5,879,691	5,595,405	5,293,644
Obligations Under Capital Leases (a)	13,397	14,743	14,425	13,987	14,806
Income Data:					
Operating Revenues	$ 5,800,095	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684
Income/(Loss) from Continuing Operations	260,828	245,896	132,936	(256,903)	70,423
Income from Discontinued Operations	-	587	337,642	4,420	46,165
Income/(Loss) Before Cumulative Effects of Accounting Changes, Net of Tax Benefits	260,828	246,483	470,578	(252,483)	116,588
Cumulative Effects of	-	-	-	(1,005)	-

Accounting Changes, Net of Tax Benefits										
Net Income/(Loss)	$	260,828	$	246,483	$	470,578	$	(253,488)	$	116,588
Common Share Data:										
Basic Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations	$	1.68	$	1.59	$	0.86	$	(1.95)	$	0.55
Income from Discontinued Operations		-		-		2.20		0.03		0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		(0.01)		-
Net Income/(Loss)	$	1.68	$	1.59	$	3.06	$	(1.93)	$	0.91
Fully Diluted Earnings/(Loss) Per Common Share:										
Income/(Loss) from Continuing Operations	$	1.67	$	1.59	$	0.86	$	(1.95)	$	0.55
Income from Discontinued Operations		-		-		2.19		0.03		0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits		-		-		-		(0.01)		-
Net Income/(Loss)	$	1.67	$	1.59	$	3.05	$	(1.93)	$	0.91
Basic Common Shares Outstanding (Average)		155,531,846		154,759,727		153,767,527		131,638,953		128,245,860

Fully Diluted Common Shares Outstanding (Average)	155,999,240	155,304,361	154,146,669	131,638,953	128,396,076
Dividends Per Share	$ 0.83	$ 0.78	$ 0.73	$ 0.68	$ 0.63
Market Price - Closing (high) (b)	$ 31.15	$ 33.53	$ 28.81	$ 21.79	$ 20.10
Market Price - Closing (low) (b)	$ 19.15	$ 26.93	$ 19.24	$ 17.61	$ 17.30
Market Price - Closing (end of year) (b)	$ 24.06	$ 31.31	$ 28.16	$ 19.69	$ 18.85
Book Value Per Share (end of year)	$ 19.38	$ 18.79	$ 18.14	$ 15.85	$ 17.80
Tangible Book Value Per Share (end of year)	$ 17.54	$ 16.93	$ 16.28	$ 13.98	$ 15.17
Rate of Return Earned on Average Common Equity (%)	8.8	8.6	18.0	(10.7)	5.1
Market-to-Book Ratio (end of year)	1.2	1.7	1.6	1.2	1.1
Capitalization:					
Common Shareholders Equity	41 %	44 %	48 %	43 %	44 %
Preferred Stock	2	2	2	2	2
Long-Term Debt (a)	57	54	50	55	54
	100 %	100 %	100 %	100 %	100 %

(a)

Includes portions due within one year, but excludes RRBs.

(b)

Market price information reflects closing prices as reflected by the New York Stock Exchange.

CL&P Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2008	2007	2006	2005	2004
Operating Revenues	$ 3,558,361	$ 3,681,817	$ 3,979,811	$ 3,466,420	$ 2,832,924
Net Income	191,158	133,564	200,007	94,845	88,016
Cash Dividends on Common Stock	106,461	79,181	63,732	53,834	47,074
Property, Plant and Equipment, net	5,089,124	4,401,846	3,634,370	3,166,692	2,824,877
Total Assets	8,336,118	7,018,099	6,321,294	5,765,072	5,306,913
Rate Reduction Bonds	378,195	548,686	743,899	856,479	995,233
Long-Term Debt (a)	2,270,414	2,028,546	1,519,440	1,258,883	1,052,891
Preferred Stock - Non-Redeemable	116,200	116,200	116,200	116,200	116,200
Obligations Under Capital Leases (a)	11,207	13,602	14,264	13,488	14,093

PSNH Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	2008	2007	2006	2005	2004
Operating Revenues	$ 1,141,202	$ 1,083,072	$ 1,140,900	$ 1,128,427	$ 968,749
Net Income	58,067	54,434	35,323	41,739	46,641
Cash Dividends on Common Stock	36,376	30,720	41,741	42,383	27,186
Property, Plant and Equipment, net	1,580,985	1,388,405	1,242,378	1,155,423	1,031,703
Total Assets	2,628,833	2,106,969	2,071,276	2,294,583	2,205,374
Rate Reduction Bonds	235,139	282,018	333,831	382,692	428,769
Long-Term Debt (a)	686,779	576,997	507,099	507,086	457,190
Obligations Under Capital Leases (a)	1,931	1,141	1,356	498	712

WMECO Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars)	**2008**	**2007**	**2006**	**2005**	**2004**
Operating Revenues	$ 441,527	$ 464,745	$ 431,509	$ 409,393	$ 379,229
Net Income	18,330	23,604	15,644	15,085	12,373
Cash Dividends on Common Stock	39,706	12,779	7,946	7,685	6,485
Property, Plant and Equipment	624,205	559,357	526,094	499,317	468,884
Total Assets	1,048,489	991,088	988,693	945,996	922,472
Rate Reduction Bonds	73,176	86,731	99,428	111,331	122,489
Long-Term Debt (a)	303,868	303,872	261,777	259,487	207,684

(a)

Includes portions due within one year, but excludes RRBs.

Item 7.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related combined notes included in this Annual Report on Form 10-K. References in this Annual Report to "NU," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. All per share amounts are reported on a fully diluted basis.

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

The discussion below also includes non-GAAP measures referencing our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation with Consolidated Edison, Inc. (Con Edison), and our 2006 earnings and EPS excluding two significant, discrete impacts, which are the gain from the sale of our competitive generation business and a reduction in income tax expense at The Connecticut Light and Power Company (CL&P) pursuant to a Private Letter Ruling (PLR) issued by the Internal Revenue Service (IRS). We use these non-GAAP measures to more fully explain and compare the 2008, 2007 and 2006 results without including the impact of these items. Due to the nature and significance of these amounts, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to investors in analyzing historical and future performance. These measures should not be considered as alternatives to reported net income or EPS determined in accordance with GAAP as indicators of operating performance.

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

Financial Condition and Business Analysis

Current Economic Conditions: As widely reported, the capital and credit markets are experiencing uncertainty and volatility to an unprecedented extent. This disruption has weakened and may continue to weaken economic conditions in parallel with the general decline in consumer confidence in the Northeast and throughout the United States. So far, the limited access to capital and higher cost of capital for businesses and consumers has reduced spending, resulted in job losses, and pressured economic growth for the foreseeable future. These weak economic conditions have affected and could continue to affect our revenues and future earnings growth and could result in greater risk of default by our counterparties, including customers, weaker sales growth, increased energy conservation, and higher bad debt expense, among other things. The weak economic conditions are also expected to put pressure on our ability to obtain distribution rate relief or to receive approvals on major transmission projects that will ultimately increase customer rates. We have included our best estimate of the impacts of these factors in the assumptions that were used to develop our earnings guidance; however, we are unable to predict the ultimate impact of these conditions on our results of operations, financial position, or liquidity.

In addition, we expect to make significant levels of investments in our capital projects in 2009 through 2013. The disruption in the capital markets has limited some companies ability to access the capital and credit markets to support their operations and refinance debt and has led to higher financing costs compared to recent years. We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for our capital requirements, including construction costs. We believe our current credit ratings will allow us to have access to the capital markets as needed (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). However, events beyond our control, such as the disruption in global capital and credit markets that occurred in September 2008, may create further uncertainty that could increase our cost of capital or impair our ability to access the capital markets. In addition, certain of NU s subsidiaries rely, in part, on NU parent for access to capital. Circumstances that limit NU parent s access to capital could impair its ability to provide those companies with needed capital. At this point in time, while the impact of continued market volatility and the extent and impacts of the ongoing economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity.

Executive Summary

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

Results, Strategy and Outlook:

.

We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share.

.

After payment of CL&P preferred dividends, our regulated companies, which consist of CL&P, Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Yankee Gas Services Company (Yankee Gas), earned $289.1 million, or $1.85 per share, in 2008, compared with $228.7 million, or $1.47 per share, in 2007. The 2008 results included earnings of $150.8 million in the distribution segment (which includes the generation segment of PSNH and gas distribution segment of Yankee Gas), and $138.3 million in the transmission segment. In 2007, our distribution segment earned $146.2 million and our transmission segment earned $82.5 million.

.

Our competitive businesses, or NU Enterprises, Inc. (NU Enterprises), earned $13.1 million, or $0.08 per share, in 2008, compared with $11.7 million, or $0.08 per share, in 2007.

.

NU parent and other companies recorded net expenses of $41.4 million, or $0.26 per share, in 2008, compared with net income of $6.1 million, or $0.04 per share, in 2007. Excluding the litigation settlement charge related to Con Edison, NU parent and other companies recorded net expenses of $11.6 million, or $0.07 per share, in 2008.

.

In 2008, CL&P completed the final three of its four major transmission projects in southwest Connecticut. The projects were completed approximately $80 million below their $1.68 billion budget and the final project was completed approximately one year ahead of schedule. Also, in October 2008, CL&P and WMECO filed siting applications to build their portions of the $714 million Greater Springfield Reliability Project, which is the largest project within the New England East-West Solutions (NEEWS) series of projects. Refer to "Business Developments and Capital Expenditures - Regulated Companies - Transmission Segment" in this Management s Discussion and Analysis for further discussion.

.

We project consolidated 2009 earnings of between $1.80 per share and $2.00 per share, including earnings of between $1.00 per share and $1.10 per share at our distribution segment, between $0.85 per share and $0.90 per share at our transmission segment and between $0.00 per share and $0.05 per share at our remaining competitive businesses, and net expenses of $0.05 per share at NU parent and other companies. This projection assumes the issuance of between $250 million and $300 million of additional equity in mid-2009. Our 2009 forecast reflects our expectations of lower electric sales and higher pension and uncollectible expense than what we experienced in 2008, due to current economic conditions.

.

During 2008, we announced that our corporate headquarters will be relocated from its current location in Berlin, Connecticut to a recently purchased office building in downtown Hartford, Connecticut. We expect to move approximately 175 corporate employees into Hartford by the summer of 2009.

Legal, Regulatory and Other Items:

.

On January 28, 2008, the Connecticut Department of Public Utility Control (DPUC) approved an increase in CL&P s annual distribution rates of $77.8 million, effective February 1, 2008, and an incremental $20.1 million annual increase, effective February 1, 2009.

.

On March 13, 2008, we entered into a settlement agreement with Con Edison that settled all claims in the civil lawsuit between Con Edison and us relating to our proposed but unconsummated merger. Under the terms of the settlement agreement, we paid Con Edison $49.5 million on March 26, 2008, which resulted in an after-tax charge of $29.8 million. This amount is not recoverable from ratepayers.

.

On March 24, 2008, the Federal Energy Regulatory Commission (FERC) issued a rehearing order confirming its initial decision setting the base return on equity (ROE) for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the New England Independent System Operator (ISO-NE) Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million ($4.9 million for CL&P) in transmission segment earnings related to this order.

.

On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund to customers approximately $5.8 million in previous recoveries through Yankee Gas' Purchased Gas Adjustment (PGA) clause. Yankee Gas results for 2008 reflect an after-tax charge of $3.5 million associated with that decision.

.

On July 16, 2008, the Massachusetts Department of Public Utilities (DPU) issued a decision requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal to fully decouple distribution revenues from kilowatt-hour (KWH) sales.

.

On July 17, 2008, the FERC confirmed the 100 basis point incentive ROE for the Middletown-Norwalk transmission project and approved an additional 50 basis points, capped at the overall ROE limit, to the ROE CL&P will earn on the advanced technology aspects of its 24-mile underground portion of the 69-mile project, which entered service in December 2008. This decision adds approximately $0.9 million to CL&P s annual transmission segment earnings beginning in 2009.

.

In October 2008, CL&P had entered into contracts for differences (CfDs) with developers of three peaking generation units approved by the DPUC. These units will have a total of approximately 500 megawatts (MW) of peaking capacity. As directed by the DPUC, CL&P and The United Illuminating Company (UI) entered into a sharing agreement, whereby CL&P is responsible for

80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P s portion of the costs and benefits will be paid by or refunded to its customers.

.

On November 17, 2008, the FERC issued an order granting incentives and rate amendments to National Grid USA and us for NEEWS transmission upgrade components. Our portion of these components is currently estimated to comprise about $1.41 billion of the total $1.49 billion cost estimate for our portion of NEEWS. The approved incentives included cash recovery through rates for 100 percent construction work in progress (CWIP), an incentive ROE of 12.89 percent and recovery of prudently incurred costs associated with project elements that may be cancelled for reasons outside of our control or National Grid USA's control.

.

On December 11, 2008, a major ice storm struck portions of New England causing approximately $100 million of damage to PSNH's, WMECO's and CL&P's distribution systems. This was the most severe ice storm in PSNH's history, and most of the $100 million in damages was to its system. CL&P s system suffered the least amount of damage from the storm. Some of these costs are covered by insurance, a small portion was expensed in 2008 and the balance should be recoverable in future rates and has been deferred or capitalized. None of the companies experienced a material impact to their results of operations from this storm.

.

On December 12, 2008, NU and NSTAR submitted a joint petition for a declaratory order to the FERC to allow NU and NSTAR to enter into a bilateral transmission services agreement with H.Q. Energy Services (U.S.) Inc. (HQUS), a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR would sell 1,200 MW of firm electric transmission service over a newly constructed, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver into New England this same amount of firm electric power from Canadian low-carbon energy resources. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. Our portion of this project is currently estimated to cost approximately $525 million. Refer to "Business Development and Capital Expenditures" in this Management s Discussion and Analysis for further discussion.

.

On January 15, 2009, the DPUC issued a final decision reversing its December 2005 draft decision regarding CL&P s proposed methodology to calculate the variable incentive portion of its transition service procurement fee in 2004. The final decision concluded that CL&P was not eligible for this procurement incentive. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings. A $5.8 million pre-tax charge (approximately $3.5

million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers was established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

Liquidity:

.

While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for NU parent and our regulated companies are all stable. Our companies have modest risk of calls for collateral. We also have only one series of bonds maturing before 2012 ($50 million in the second quarter of 2009), and capital expenditures projected for 2009 are significantly less than 2008. No cash contributions to our pension plan are required during 2009; however, due to the substantial decrease in our pension plan assets in 2008 and unless there is a change in current funding requirements, we will be required to make an estimated $150 million contribution in 2010. Refer to "Liquidity - Impact of Financial Market Conditions" in this Management s Discussion and Analysis for further discussion.

.

Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007. We were successful in meeting our extensive 2008 capital plan. In 2009, we expect cash capital expenditures to be approximately $880 million, primarily because of lower transmission capital expenditures at CL&P.

.

We issued $760 million of long-term debt in 2008 at rates of between 5.65 percent and 6.9 percent, and $250 million in February 2009 at a rate of 5.5 percent. We expect further external financings totaling $400 million to $450 million in mid-2009 (or earlier depending on market opportunities), including approximately $150 million of long-term debt by PSNH, subject to regulatory approval, and between $250 million and $300 million of additional equity by NU parent. Refer to "Liquidity" in this Management s Discussion and Analysis for further discussion.

.

On June 30, 2008, due to the availability and lower relative cost of other liquidity sources, CL&P chose to terminate the arrangement under which CL&P could sell to a financial institution up to $100 million of accounts receivable and unbilled revenues.

.

After rate reduction bond (RRB) payments included in financing activities, we had cash flows provided by operations in 2008 of $418.5 million, which represented an increase of $429.8 million from 2007. This increase was primarily due to the absence in 2008 of approximately $400 million in tax payments in 2007 related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. Refer to "Liquidity - Consolidated" in this Management s Discussion and Analysis for further discussion.

.

In 2009, we project operating cash flows of approximately $500 million, after repayment of RRBs. This projection does not include any contributions to our pension plan, as they are not required to be paid in 2009. The primary reasons for the projected increase from 2008 are that our major southwest Connecticut transmission projects will be fully reflected in rates in 2009 due to their completion in the second half of 2008 and that the 2008 Con Edison settlement payment is absent in 2009, partially offset by the payment in 2009 of major storm costs incurred in December 2008 that likely will not be fully recovered from customers in 2009. Excluding potential contributions to our pension plan, we currently project our internally-generated cash flows to grow to approximately $1 billion by 2013.

.

As of February 25, 2009, we had approximately $466 million of externally invested cash. At this time, we also had approximately $51 million of borrowing availability on our revolving credit lines, excluding the remaining unfunded commitment of Lehman Brothers Commercial Bank (LBCB) (refer to "Liquidity - Impact of Financial Market Conditions" for further discussion).

Overview

Consolidated: We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007 and $470.6 million, or $3.05 per share, in 2006. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share. Results for 2006 included an after-tax gain of $314 million, or $2.03 per share, associated with the sale of our competitive generation business, and a reduction in income tax expense at CL&P of $74 million, or $0.48 per share, pursuant to a PLR received from the IRS. Results in 2007 and 2006 included discretionary pre-tax donations to the NU Foundation (Foundation) of $3 million and $25 million, respectively. There was no such contribution in 2008. A summary of our earnings, which also reconciles the non-GAAP measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, to the most directly comparable GAAP measures of consolidated net income and fully diluted EPS, for 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,					
	2008		2007		2006	
(Millions of Dollars, except per share amounts)	**Amount**	**Per Share**	**Amount**	**Per Share**	**Amount**	**Per Share**
Net Income (GAAP)	$ 260.8	$ 1.67	$ 246.5	$ 1.59	$ 470.6	$ 3.05
Regulated companies	$ 289.1	$ 1.85	$ 228.7	$ 1.47	$ 183.3	$ 1.19
	13.1	0.08	11.7	0.08	(102.7)	(0.66)

Competitive businesses						
NU parent and other companies	(11.6)	(0.07)	6.1	0.04	2.0	0.01
Non-GAAP earnings	290.6	1.86	246.5	1.59	82.6	0.54
Con Edison litigation charge	(29.8)	(0.19)	-	-	-	-
Gain on sale of competitive business	-	-	-	-	314.0	2.03
Reduction in income tax expense (PLR)	-	-	-	-	74.0	0.48
Net Income (GAAP)	$ 260.8	$ 1.67	$ 246.5	$ 1.59	$ 470.6	$ 3.05

Regulated Companies: Our regulated companies segment their earnings between their electric transmission segments and their electric and gas distribution segments, with PSNH generation included in the electric distribution segment. A summary of regulated company earnings by segment for 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
CL&P Transmission*	$ 115.6	$ 66.7	$ 46.9
PSNH Transmission	16.7	10.7	8.3
WMECO Transmission	6.0	5.1	4.6
Total Transmission*	$ 138.3	$ 82.5	$ 59.8
CL&P Distribution*	$ 70.0	$ 61.4	$ 147.6
PSNH Distribution	41.4	43.7	27.0
WMECO Distribution	12.3	18.5	11.0
Yankee Gas	27.1	22.6	11.9
Total Distribution*	$ 150.8	$ 146.2	$ 197.5
Net Income - Regulated Companies*	$ 289.1	$ 228.7	$ 257.3

*After preferred dividends of CL&P in all years.

The higher 2008 and 2007 transmission segment earnings reflect a higher level of investment in this segment as we continued to build out our transmission infrastructure to meet the region s reliability needs. CL&P s transmission segment earnings increased primarily due to the investment by CL&P of approximately $1.6 billion since the beginning of 2005 in the southwest Connecticut transmission projects that were completed in 2008. At December 31, 2008, our transmission segment rate base was approximately $2.4 billion, compared with approximately $1.5 billion at December 31, 2007.

CL&P s 2008 distribution segment earnings were $8.6 million higher than 2007 primarily due to higher distribution revenues resulting from a distribution rate increase effective February 1, 2008, a settlement of federal tax matters, a lower effective income tax rate, and higher other revenues resulting from financial incentives under Connecticut's "Act Concerning Energy Independence" to promote distributed generation and demand side management. These items were partially offset by a 3.7 percent decline in sales, higher operating costs, including full-year storm expenses, maintenance expenses, and interest expense, a $5.8 million pre-tax charge to refund the 2004 procurement incentive fee that was recognized in 2005 earnings, and losses on investments in the Trust Under

Supplemental Executive Retirement Plan ("supplemental benefit trust"). CL&P s distribution segment Regulatory ROE was 7.5 percent in 2008 and 7.9 percent in 2007. We expect CL&P s distribution segment Regulatory ROE in 2009 will be approximately 7 percent.

PSNH s distribution segment earnings in 2008 were $2.3 million lower than 2007. The decrease in 2008 earnings was primarily due to higher operating costs including full-year storm expenses, depreciation, and interest expense, a 2.5 percent decline in sales, losses on the supplemental benefit trust and the absence of a $4.5 million pre-tax benefit from the implementation of the retail transmission cost tracking mechanism in the second quarter of 2007. These items were partially offset by an increase in PSNH s distribution revenues that resulted from distribution rate increases on July 1, 2007 and January 1, 2008, a pre-tax adjustment to its generation cost recovery mechanism of $1.9 million, and a settlement of federal tax matters. PSNH s distribution segment Regulatory ROE was 8.3 percent in 2008 and 9.5 percent in 2007. We expect PSNH s distribution segment Regulatory ROE in 2009 will be approximately 8 percent, with the earnings of the generation portion of this segment based on its authorized ROE of 9.8 percent.

WMECO s 2008 distribution segment earnings were $6.2 million lower than 2007 primarily due to higher operating costs, including full-year storm expenses, and uncollectibles expense, a 4.2 percent decline in sales, a $1.6 million pre-tax charge related to a DPU ruling on WMECO s 2005 and 2006 transition cost reconciliations, a $1.3 million pre-tax charge for potential refunds to customers from an assessment under the DPU s service quality index criteria, and losses on the supplemental benefit trust. These items were partially offset by a $3 million annualized distribution rate increase that took effect January 1, 2008 and a settlement of federal tax matters. WMECO s distribution segment Regulatory ROE was 7.2 percent in 2008 and 9.7 percent in 2007. We expect WMECO s distribution segment Regulatory ROE in 2009 will be approximately 8 percent.

Yankee Gas earnings in 2008 were $4.5 million higher than 2007 primarily due to a distribution rate increase that took effect on July 1, 2007 and a 2.1 percent increase in firm natural gas sales. These increases were partially offset by higher operating costs, including uncollectibles expense, maintenance expense, and interest expense, and a DPUC order requiring Yankee Gas to refund $5.8 million of previous gas cost recoveries. Yankee Gas Regulatory ROE was 8.3 percent in 2008 and 8.7 percent in 2007. We expect Yankee Gas Regulatory ROE in 2009 will be approximately 9 percent.

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

		Electric		
	CL&P	PSNH	WMECO	Total

	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	We Norr Perc Dec
Residential	(4.1)%	(2.7)%	(2.2)%	(1.0)%	(3.1)%	(2.1)%	(3.6)%	
Commercial	(1.3)%	(0.7)%	(1.2)%	(0.4)%	(2.6)%	(2.1)%	(1.4)%	
Industrial	(9.8)%	(9.3)%	(6.1)%	(5.4)%	(8.7)%	(8.5)%	(8.6)%	
Other	(3.2)%	(3.2)%	2.2 %	2.2 %	(14.6)%	(14.6)%	(3.7)%	
Total	(3.7)%	(2.8)%	(2.5)%	(1.6)%	(4.2)%	(3.5)%	(3.5)%	

A summary of our retail electric sales in gigawatt hours (GWH) for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for 2008 and 2007 is as follows:

	Electric			Firm Natural Gas		
	2008	2007	Percentage Decrease	2008	2007	Percentage (Decrease)/ Increase
Residential	14,509	15,051	(3.6)%	13,467	13,742	(2.0)%
Commercial	14,885	15,103	(1.4)%	12,939	12,965	(0.2)%
Industrial	5,149	5,635	(8.6)%	13,310	12,193	9.2 %
Other	340	353	(3.7)%	-	-	- %
Total*	34,883	36,142	(3.5)%	39,717	38,900	2.1 %

*Amounts may not total due to rounding of GWH.

Retail electric sales for 2008 were lower than 2007. The 2008 weather normalized decrease of 2.6 percent reflects the fact that our customers are responding to the increased costs of energy and to the adverse economic conditions of our region and the nation. We believe customers will continue to respond to these factors and to the recent disruptions and ongoing uncertainty in the financial markets, and have estimated a decline of approximately 1 percent in weather normalized electric sales in 2009, which is reflected in our earnings guidance. We experienced positive growth in our weather normalized electric sales of 1.3 percent for January 2009.

Changes in electric sales, however, have less of an impact on the earnings of the electric companies than in prior years because non-distribution rate revenues, which represented approximately 76 percent of electric company revenues in 2008, are tracked and reconciled to actual costs. Non-distribution rate revenues include the energy, stranded cost, retail transmission and federally mandated congestion costs (FMCC) charges and other components of rates. For non-distribution rate revenues, the only impact to earnings is from carrying costs on over- or underrecoveries. With respect to the distribution revenues, about two-thirds of CL&P's and WMECO's revenues and about one-half of

PSNH's revenues are recovered through charges that are not dependent on overall sales volumes, such as the customer charge and the demand charge.

In addition to the manner in which the distribution rate revenues are recovered from customers, there are other reasons why changes in 2008 sales as compared to 2007 had less of an impact on our earnings. For example, some of the decline in 2008 industrial sales was due to qualified distributed generation in Connecticut replacing our distribution. Under Connecticut statute, CL&P is entitled to recover this lost distribution revenue through its FMCC charge. Also, some of the decline in 2008 commercial sales was attributable to certain generators who, in previous periods, took station service from CL&P as retail commercial customers but now are served directly by ISO-NE as wholesale customers. These customers are interconnected to the transmission system and do not contribute to distribution revenues, therefore the loss of load from these customers in 2008 did not impact our earnings.

Firm natural gas sales in 2008 were higher than 2007. The 2008 results reflect warmer weather in the first quarter, colder weather in the fourth quarter and an increase in industrial sales primarily due to customer-owned gas-fired distributed generation and favorable natural gas prices relative to oil. Similar to our electric distribution companies, Yankee Gas recovers a significant portion of its distribution revenues, approximately 40 percent, through charges that are not dependent on usage. Our 2009 earnings guidance reflects an estimated increase in weather normalized firm gas sales of approximately 2.5 percent.

Consistent with our sales results in 2008, our uncollectibles expense has also been influenced by the adverse economic conditions of our region. Our write-offs as a percentage of revenues increased in 2008 for all our distribution companies. Similar to changes in our retail sales, changes in our uncollectibles expense have less of an impact on earnings of our distribution companies than in prior years. For example, a portion of the uncollectibles expense for each of the electric distribution companies is allocated to its respective energy supply rate and recovered as a tracked expense. CL&P, PSNH and WMECO implemented their trackers for this allocated portion of uncollectibles expense on February 1, 2008, July 1, 2007, and January 1, 2007, respectively. Additionally, for CL&P and Yankee Gas, write-offs attributable to hardship customers are tracked and fully recovered in the System Benefits Charge (SBC) as uncollectible expense and in the base distribution rate as amortization expense, respectively. In 2008, our total uncollectibles expense was approximately $75 million or $25 million higher than 2007. Over $13 million of the increase was attributable to hardship accounts at CL&P. From a nontracked uncollectibles expense perspective, the 2008 expense was approximately $9 million greater than we originally expected. In 2009, we expect our total uncollectibles expense will be slightly higher than 2008 and the nontracked portion of uncollectibles expense to increase to approximately $30 million in 2009. This anticipated increase of 10 percent or $3 million is reflected in our 2009 earnings guidance.

Competitive Businesses: NU Enterprises, which continues to manage to completion its remaining wholesale marketing contracts and manages its energy services activities, earned $13.1 million in 2008, or $0.08 per share, compared with earnings of $11.7 million in 2007, or $0.08 per share, and $211.3 million, or $1.37 per share, in 2006. The 2008 results include a net after-tax reduction of earnings of $3.2 million associated with the implementation of Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements." Competitive business earnings in 2008 also included positive mark-to-market after-tax results of $4.3 million associated with Select Energy, Inc.'s (Select Energy) wholesale marketing contracts, as compared to negative mark-to-market after-tax results of $3.8

million in 2007. The higher competitive business earnings in 2006 were attributable to the $314 million after-tax gain on the sale of the competitive generation business, partially offset by $70.3 million of losses at the retail marketing business, which was sold on June 1, 2006.

NU Parent and Other Companies: NU parent and other companies recorded net expenses of $41.4 million, or $0.26 per share, in 2008, compared with net income of $6.1 million, or $0.04 per share, in 2007, and net income of $2 million, or $0.01 per share, in 2006. The net expenses in 2008 primarily relate to the payment by NU parent to Con Edison of $49.5 million in March 2008 as part of a comprehensive settlement of litigation initiated in 2001 over the proposed but unconsummated merger between the two companies. The decrease in net income from 2007 was also the result of reduced interest income for NU parent on a significantly lower level of cash in 2008. NU parent carried a high level of cash in the first quarter of 2007 after the sale of our competitive generation businesses on November 1, 2006. Most of that cash was either invested in the regulated companies in 2007 to support those companies   capital programs or used to pay taxes due in March 2007 on the competitive generation business sales. Additionally, NU parent interest expense increased in 2008 due to the replacement of $150 million of 3.3 percent senior notes that matured on June 1, 2008 with $250 million of 5.65 percent senior notes.

Future Outlook

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

	2009 EPS Range			
(Approximate amounts)		**Low**		**High**
Fully Diluted EPS (GAAP)	$	1.80	$	2.00
Regulated companies:				
Distribution segment	$	1.00	$	1.10
Transmission segment		0.85		0.90
Total regulated companies		1.85		2.00
Competitive businesses		0.00		0.05
NU parent and other companies		(0.05)		(0.05)
Fully Diluted EPS (GAAP)	$	1.80	$	2.00

This projection assumes the issuance of between $250 million and $300 million of additional equity in mid-2009. Our distribution rates are based in part on historic operation and maintenance costs, including pension and other postretirement costs and uncollectible expense. Primarily as a result of a significant decline in our pension assets due to current financial market conditions, we expect that higher pension costs will result in a $0.10 per share negative impact on earnings in 2009, as compared with 2008. The distribution segment earnings forecast noted above reflects our expectations of lower electric sales and higher pension and uncollectible expense than what we experienced in 2008.

Long-Term Growth Rate: We project that we will achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent over 2007 EPS of $1.59 through 2013. Based on current economic conditions, we believe we will likely be at the lower end of this range. This EPS growth rate assumes achieved Regulatory ROEs of approximately 12 percent for transmission, between 9.5 percent and 10 percent for generation and between 9 percent and 9.5 percent for distribution investments. We believe this growth will be achieved if our capital program is successfully deployed according to our plans, distribution rate cases are approved to earn reasonable Regulatory ROEs and FERC's present transmission policies remain consistent and enable us to achieve projected transmission ROEs.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, allowance for funds used during construction (AFUDC), and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors in determining rate base), totaled $1.3 billion in both 2008 and 2007 and $945.8 million in 2006. These amounts include $33.2 million, $16 million and $17.6 million in 2008, 2007 and 2006, respectively, that related to our corporate service company and other affiliated companies that support the regulated companies.

Regulated Companies: We project making up to approximately $7 billion in capital investments for the regulated companies from 2009 through 2013. This projection includes capital expenditures of approximately $525 million for our portion of the costs associated with the new transmission initiative with NSTAR and HQUS, and approximately $150 million for our corporate service companies supporting the regulated companies. Given current financial conditions, we continue to carefully examine each investment to assess customer benefits, shareholder benefits and the ability to raise necessary capital.

A summary of our projected capital expenditures for 2009 through 2013 is as follows:

	Year					
(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2009-2013 Totals**
CL&P Transmission	$ 97	$ 128	$ 267	$ 322	$ 160	$ 974
PSNH Transmission	58	177	400	273	154	1,062
WMECO Transmission	70	121	308	306	83	888
Other Transmission	-	20	95	205	205	525
Totals - Transmission	225	446	1,070	1,106	602	3,449
CL&P Distribution	278	352	338	309	311	1,588
PSNH Distribution	96	115	117	114	117	559
WMECO Distribution	30	38	33	33	34	168
Totals - Electric Distribution	404	505	488	456	462	2,315
PSNH Generation	156	199	144	83	41	623
Yankee Gas Distribution	66	90	92	74	77	399
Corporate service companies	70	34	21	13	12	150
Totals	$ 921	$ 1,274	$ 1,815	$ 1,732	$ 1,194	$ 6,936

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

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

35

The projected capital expenditures and rate base amounts reflected above assume that PSNH s Clean Air Project will be completed by the end of 2012 at a cost of $457 million. They also assume that $1.49 billion in transmission projects associated with NEEWS will be completed before the end of 2013. Numerous factors, some of which are beyond our control, may impact the regulated companies rate base amounts above, including the level and timing of capital expenditures and plant placed in service and regulatory approvals.

Transmission Segment: Transmission segment capital expenditures decreased by $47.5 million in 2008 as compared with 2007 primarily due to reduced expenditures at CL&P associated with its transmission system projects in southwest Connecticut. A summary of transmission segment capital expenditures by company in 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,					
(Millions of Dollars)		**2008**		**2007**		**2006**
CL&P	$	586.3	$	660.6	$	415.6
PSNH		81.9		80.7		36.1
WMECO*		44.2		19.3		13.0
HWP*		1.9		1.2		0.8
Totals	$	714.3	$	761.8	$	465.5

*

Does not include the transfer of $4 million in transmission assets from Holyoke Water Power Company (HWP) and its subsidiary, Holyoke Power and Electric Company (HP&E), to WMECO in December 2008.

Of its $586.3 million in transmission capital expenditures in 2008, CL&P invested approximately $470 million to complete its $1.6 billion series of four major transmission projects in southwest Connecticut. The first of those projects, the 21-mile 345 kilovolt (KV)/115 KV overhead and underground transmission line between Bethel, Connecticut and Norwalk, Connecticut, was placed in service in 2006. The remaining three projects that entered service in 2008 are as follows:

.

The 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut (Middletown-Norwalk) that was constructed jointly with UI. CL&P's portion of this project cost approximately $950 million, $100 million lower than the earlier estimate of $1.05 billion primarily due to a decrease in capitalized financing costs because of the earlier-than-expected in service date. Of the $950 million, approximately $334 million was capitalized in 2008. The

45-mile overhead section of the project entered service on August 28, 2008. The 24-mile underground section entered service on December 16, 2008.

.

The two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), which entered service ahead of schedule on November 11, 2008. This project cost approximately $239 million, which is $16 million higher than the previous estimate due to increased construction costs related to underground obstacles. Of the $239 million, approximately $102 million was capitalized in 2008.

.

The 138 KV, 11-mile undersea transmission project between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable), which was completed in September 2008. CL&P's 51 percent portion of the project with Long Island Power Authority is estimated to be approximately $78 million, which represents a $7 million increase over the previous estimate. Of the $78 million, approximately $33 million was capitalized in 2008.

In 2008, in addition to the approximately $470 million invested in the three projects noted above, CL&P, PSNH, WMECO and HWP invested approximately $244 million in other transmission projects.

In October 2008, we commenced state regulatory filings for our next series of major transmission projects, NEEWS. That series of projects involves our construction of new overhead 345 KV lines in Massachusetts and Connecticut as well as associated substation work and 115 KV rebuilds. One of the projects will connect to a new transmission line that National Grid USA plans to build in Rhode Island and Massachusetts. On September 24, 2008, the ISO-NE issued its final technical approval of the NEEWS projects, which was a precursor to the siting application process. We estimate that CL&P s and WMECO s total capital expenditures for these projects will be $1.49 billion through 2013. In 2008, CL&P and WMECO capitalized approximately $19.7 million and $23.2 million, respectively, in costs associated with NEEWS.

The first of the NEEWS projects, the Greater Springfield Reliability Project, which involves a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. This project is expected to cost approximately $714 million if built according to our preferred route and configuration. CL&P filed its application to build the Connecticut portion of the Greater Springfield Reliability Project with the Connecticut Siting Council (Siting Council) on October 20, 2008. WMECO filed its application to build its portion of the project with the Massachusetts Energy Facilities Siting Board on October 27, 2008. The Connecticut Energy Advisory Board is currently reviewing Connecticut-based generation, demand side management and other proposed alternatives to the Greater Springfield Reliability Project, which must be submitted to the Siting Council by March 19, 2009. The Siting Council has preliminarily set dates for hearings, public comments and site visits on the Connecticut portion of the project in the second quarter of 2009. If the overall project is approved in 2010 as expected, we currently expect to commence construction in late 2010 and place the project in service in 2013.

Our second major NEEWS project is the Interstate Reliability Project, which is being designed and built in coordination with National Grid USA. CL&P's share of this project includes an approximately 40-mile, 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid USA is designing. We expect CL&P's share of this project to cost approximately $250 million. Municipal consultations concluded in November 2008, and CL&P plans to file siting

36

applications with Connecticut regulators by the third quarter of 2009 with construction beginning as early as late 2010. We currently expect the project to be placed in service as early as 2012.

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide another 345 KV connection to move power across the state of Connecticut. The timing of this project would be six to twelve months behind the other two projects, and CL&P currently expects to file the siting application in early 2010, with construction beginning in 2011. The project is currently expected to be placed in service in 2013 at a cost of approximately $315 million. Included as part of NEEWS are approximately $210 million of associated reliability related expenditures, some of which may be incurred in advance of the three major projects.

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

On December 12, 2008, NU and NSTAR submitted a joint petition for a declaratory order to the FERC. The petition requests a ruling by the FERC that would allow NU and NSTAR to enter into a bilateral transmission services agreement with HQUS, a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR would sell 1,200 MW of firm electric transmission service over a newly constructed, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver into New England this same amount of firm electric power from Canadian low-carbon energy resources. If FERC issues the declaratory order as we anticipate, NU and NSTAR would subsequently seek approval from FERC of the specific terms and conditions of the transmission arrangement. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. This project would provide a competitive source of low-carbon power that is favorable in comparison to current alternatives and would also provide for an expansion of New England s transmission system without raising regional transmission rates. NU, NSTAR and HQUS have also begun discussions on the specifics of a potential long-term power purchase agreement that would ensure the line is utilized to bring low-carbon power to benefit New England customers. A FERC order is expected in the first half of 2009, and if the order approves the proposal, then NU and NSTAR plan to negotiate a power purchase agreement with HQUS later in 2009. The terms of such agreement would be subject to regulatory approvals in several states.

Assuming completion of an acceptable power purchase agreement and receipt of all necessary state and federal regulatory approvals, we expect this project to be under construction between 2011 and 2014. Our portion of the costs of this project is currently estimated to be approximately $525 million. HQUS will reimburse NU and NSTAR for the total costs of this project, including an investment return to these companies, over the estimated 40-year operating life of the transmission line. NU and NSTAR s intent is to create an agreement that approximates a typical FERC approved cost-of-service rate structure. The revenue recovery model will ultimately require FERC approval.

<u>Distribution Segment</u>: A summary of distribution segment capital expenditures by company in 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
CL&P	$ 296.6	$ 283.3	$ 210.3
PSNH	98.2	88.3	77.5
WMECO	37.8	34.0	30.0
Totals - Electric distribution (excluding generation)	432.6	405.6	317.8
Yankee Gas	44.0	63.7	89.9
Other	0.5	0.4	2.3
Total distribution	477.1	469.7	410.0
PSNH generation	74.0	35.3	32.1
Total distribution segment	$ 551.1	$ 505.0	$ 442.1

PSNH s Clean Air Project is expected to cost approximately $457 million, which will be recovered through its generation rates under New Hampshire law. PSNH commenced preliminary site work for this project in 2008. The project is scheduled to be completed by the end of 2012. As of December 31, 2008, PSNH had capitalized approximately $27.5 million associated with this project, of which $24.8 million was capitalized in 2008. Refer to "Regulatory Developments and Rate Matters - New Hampshire - Merrimack Clean Air Project" for further discussion, including the status of the New Hampshire Supreme Court proceedings and their effect on this project.

On February 15, 2008, Yankee Gas and NRG Energy, Inc. (NRG) entered into a settlement agreement, which, among other things, allowed for the recovery by Yankee Gas of approximately $17.5 million of capital costs and expenses related to an NRG subsidiary's generating plant construction project that was abandoned. The 2008 capital expenditures at Yankee Gas were offset by this $17.5 million recovery, and the 2007 capital expenditures included $12 million spent on its $108 million liquefied natural gas storage and production facility in Waterbury, Connecticut, which was placed in service in July 2007.

Liquidity

Consolidated: We had $89.8 million of cash and cash equivalents on hand at December 31, 2008, compared with $15.1 million at December 31, 2007. As of February 25, 2009, we had approximately $466 million of externally invested cash. Refer to "Impact of Financial Market Conditions" below for further discussion.

We had positive consolidated operating cash flows in 2008 of $418.5 million, after RRB payments included in financing activities, compared with negative operating cash flows of $11.3 million in 2007 and positive operating cash flows of $233.7 million in 2006, both after RRB payments. The increase in 2008 operating cash flows was primarily due to the absence in 2008 of approximately $400 million in tax payments in 2007 related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. After factoring these cash flow impacts, the increase in operating cash flows in 2008 from 2007 was primarily due to a favorable impact of approximately $118 million from tax-related matters in 2008, which included an income tax net settlement of approximately $78 million in the fourth quarter and a reduction in income tax payments of approximately $40 million during 2008 related to bonus depreciation. The cash flow benefit of our accounts payable balances increased by $122 million, excluding approximately $50 million in unpaid costs at PSNH related to a major storm in December 2008 that are deferred and expected to be recovered from customers or insurance proceeds. These factors were partially offset by a net reduction in other working capital items resulting primarily from a net $136 million increase in accounts receivable and unbilled revenues items, which also included investments in securitizable assets.

We project consolidated operating cash flows of approximately $500 million in 2009, after RRB payments of $244 million, which represents an increase of approximately $82 million, or 19 percent, from 2008 operating cash flows, after RRB payments. This projected increase does not include any pension plan contributions, as they are not required to be paid during 2009, and is primarily due to our major southwest Connecticut transmission projects being fully reflected in rates in 2009 after their completion in the second half of 2008 and the absence in 2009 of the Con Edison settlement payment. These factors are partially offset by the payment in 2009 of major storm costs incurred in December 2008 that likely will not be fully recovered from customers in 2009. Excluding potential contributions to our Pension Plan, we currently project our internally-generated cash flows to grow to approximately $1 billion by 2013 due to our cash return on and recovery of capital investment program expenditures.

In 2008, NU parent, CL&P, PSNH and Yankee Gas issued a total of $760 million of long-term debt. On May 27, 2008, CL&P sold $300 million of first and refunding mortgage bonds due May 1, 2018 and carrying a coupon of 5.65 percent and PSNH sold $110 million of first mortgage bonds due May 1, 2018 and carrying a coupon of 6 percent. Proceeds from the CL&P and PSNH issuances were used to repay short-term debt, to fund each company s ongoing capital investment programs, and for general working capital purposes. On June 5, 2008, NU parent sold $250 million of senior unsecured notes due June 1, 2013 and carrying a coupon of 5.65 percent. Most of the proceeds were used to repay $150 million of 3.3 percent notes that matured June 1, 2008. The balance of NU parent s debt issuance was used to pay down short-term debt, a portion of which was incurred in March 2008 as a result of the $49.5 million litigation settlement payment to Con Edison. On October 7, 2008, Yankee Gas sold $100 million of privately placed first mortgage bonds due October 1, 2018 and carrying a coupon of 6.9 percent. Yankee Gas used the proceeds to repay its borrowings under the regulated companies credit facility, to fund capital investment programs and for general working capital purposes.

On February 13, 2009, CL&P issued $250 million of first and refunding mortgage bonds due February 1, 2019 and carrying a coupon of 5.5 percent. Proceeds from this issuance will be used to repay short-term debt and fund CL&P's capital investment program. In mid-2009 or earlier depending on market opportunities, we expect to issue $150 million of long-term debt at PSNH, subject to regulatory approval, and between $250 million and $300 million of additional equity. These issuances will be made primarily to repay short-term debt and fund our 2009 capital investment program, which will also be funded by available short-term borrowings and the projected growth in 2009 operating cash flows.

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

	Moody's		**S&P**		**Fitch**	
	Current	**Outlook**	**Current**	**Outlook**	**Current**	**Outlook**
NU Parent	Baa2	Stable	BBB-	Stable	BBB	Stable
CL&P	A3	Stable	BBB+	Stable	A-	Stable
PSNH	Baa1	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

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

If NU parent s senior unsecured debt ratings were to be reduced to a sub-investment grade level by either Moody's or S&P, a number of Select Energy's supply contracts would require Select Energy to post additional collateral in the form of cash or letters of credit (LOCs). If such an event were to occur, Select Energy would, under its remaining contracts, be required to provide cash or LOCs in an aggregate amount of $23.2 million to various unaffiliated counterparties and cash or LOCs in the aggregate amount of $10 million to two independent system operators, in each case at December 31, 2008. NU parent would be able to provide that collateral. If unsecured debt ratings for CL&P or PSNH were to be reduced by either Moody's or S&P, a number of supply contracts would require CL&P and PSNH to post additional collateral in the form of cash or LOCs to various unaffiliated counterparties. If these ratings were to be reduced by one level, PSNH would be required to post collateral of $1 million as of December 31, 2008. If these ratings were to be reduced by two levels or below investment grade, the amount of collateral required to be posted by CL&P and PSNH would be $1.3 million and $24.5 million, respectively, at December 31, 2008. CL&P and PSNH would be able to provide these collateral amounts.

NU paid common dividends of $129.1 million in 2008, compared with $121 million in 2007 and $112.7 million in 2006. The increase in common dividends paid from 2006 to 2008 reflects a 7.1 percent increase in the amount of NU parent s common dividend that took effect in the third quarter of 2006, a 6.7 percent increase that took effect in the third quarter of 2007 and a 6.3 percent increase that took effect in the third quarter of 2008. On February 10, 2009, our Board of Trustees declared a common dividend of $0.2375 per share, payable on March 31, 2009 to shareholders of record as of March 1, 2009, which represents a $0.10 per share, or 11.8 percent, increase on an annual basis.

The February 2009 dividend declaration reflects our new policy, announced in November 2008, of targeting a dividend payout ratio of approximately 50 percent of earnings. Our goal is to continue increasing the dividend at a rate above industry average and to provide an attractive return to shareholders. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In 2008, CL&P, PSNH, WMECO and Yankee Gas paid $106.5 million, $36.4 million, $39.7 million, and $31 million, respectively, in common dividends to NU parent. In 2008, NU parent contributed $210 million of equity to CL&P, $75.6 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

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

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in the liquidity section of this Management's Discussion and Analysis do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007 and $872.2 million in 2006. Our cash capital expenditures in 2008 included $849.5 million by CL&P, $238.9 million by PSNH, $78.3 million by WMECO, $58.3 million by Yankee Gas, and $30.4 million by other NU subsidiaries. Our cash capital expenditures in 2007 included $826.2 million by CL&P, $167.7 million by PSNH, $47.3 million by WMECO, $57.6 million by Yankee Gas, and $16 million by other NU subsidiaries. The increase in our aggregate cash capital expenditures was primarily the result of higher distribution segment capital expenditures.

NU Parent: NU parent has a credit line in a nominal aggregate amount of $500 million including the commitment of LBCB (as further discussed below), which expires on November 6, 2010. At December 31, 2008, NU parent had $87 million of LOCs issued for the benefit of certain subsidiaries (primarily PSNH) and $303.5 million of borrowings outstanding under this facility. The weighted-average interest rate on these short-term borrowings at December 31, 2008 was 3.35 percent, which is based on a variable rate plus an applicable margin based on our credit ratings. We had approximately $50 million of borrowing availability on this facility as of February 25, 2009, excluding LBCB's remaining unfunded commitment. We also had approximately $466 million of externally invested cash at February 25, 2009.

Regulated Companies: The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million including the commitment of LBCB (as further discussed below), which expires on November 6, 2010. There were $315 million of borrowings outstanding under this facility at December 31, 2008 ($188 million for CL&P, $45.2 million for PSNH, $29.9 million for WMECO). The weighted-average interest rate on these short-term borrowings at December 31, 2008 was 3.35 percent, which is based on a variable rate plus an applicable margin based on our credit ratings. We had approximately $1 million of borrowing availability on this facility as of February 25, 2009, excluding LBCB's remaining unfunded commitment. As stated above, we also had approximately $466 million of externally invested cash at February 25, 2009.

Prior to June 30, 2008, CL&P had an arrangement with CL&P Receivables Corporation (CRC), a consolidated wholly-owned subsidiary of CL&P, and a financial institution under which the financial institution could purchase up to $100 million of CL&P s accounts receivable and unbilled revenues from CRC. On June 30, 2008, CL&P chose to terminate the Receivables Purchase and Sale Agreement due to the availability and lower relative cost of other liquidity sources. At this time, we have no further plans to securitize the accounts receivable and unbilled revenues of our regulated companies and will utilize our credit facilities and other financing vehicles, as necessary, to fund the daily operating activities and capital programs of these companies.

Our debt agreements provide that NU and certain of its subsidiaries, including CL&P, PSNH and WMECO, must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to capitalization ratio. The parties to these agreements currently are and expect to remain in compliance with these covenants. Refer to Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to our consolidated financial statements included in this Annual Report on Form 10-K for further discussion of material terms and conditions of our outstanding debt agreements.

Impact of Financial Market Conditions: While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for NU parent and our regulated companies are all stable, with all their ratings and outlooks affirmed by S&P in late October 2008. Our companies have modest risk of calls for collateral due to our business model, as described further below. No cash contributions to our pension plan are required during 2009. We also have only $50 million of long-term debt maturing in 2009, and projected capital expenditures for 2009 are significantly less than 2008. In the fourth quarter of 2008, we announced a new common dividend policy that targets a payout ratio of approximately 50 percent of earnings. While this new policy may require additional cash

to fund common dividends, the incremental cash increase is relatively small and we continue to have a modest payout ratio relative to peer companies.

We successfully completed our planned long-term debt financings in 2008, as well as a CL&P bond issuance in early 2009, and we continue to have access to our two revolving credit facilities described above in a nominal aggregate amount of $900 million. The lenders under these facilities are: Bank of America, N.A.; Barclays Bank PLC; BNY Mellon, N.A.; Citigroup Inc.; HSBC Bank USA, N.A.; JPMorgan Chase Bank, N.A.; LBCB; Sumitomo Mitsui Banking Corporation; Toronto Dominion (Texas) LLC; Union Bank of California, N.A.; Wachovia Bank, N.A.; and Wells Fargo Bank, N.A. Borrowing capacity under the facility has not been reduced as a result of the 2008 merger of Wachovia and Wells Fargo. Lehman Brothers Holdings Inc., the parent of LBCB, filed for Chapter 11 bankruptcy protection in September 2008. LBCB's original aggregate lending commitment under the facilities was $85 million, $30 million of which was assigned to Sumitomo Mitsui Banking Corporation in late September, at which time LBCB had advanced approximately $23.5 million under the facilities. LBCB subsequently declined to fund the remainder of its commitment. As a result, when current loans from LBCB are repaid, we will be limited to an aggregate of $845 million of borrowing capacity under our credit facilities, which we believe will provide sufficient operating flexibility to maintain adequate liquidity. We have no other exposure to Lehman Brothers Holdings Inc. or any of its affiliates. As of December 31, 2008, we had borrowings and LOCs outstanding of approximately $706 million under the credit facilities, and approximately $793 million as of February 25, 2009, including $19.2 million remaining outstanding from LBCB. As of February 25, 2009, we also had approximately $466 million of externally invested cash.

In addition to the revolving credit facilities described above, we intend to access the capital markets, as appropriate, to fund our capital projects or otherwise meet funding needs. The availability and cost of external financings, including our expected financings in 2009 described below, will be affected by our financial condition and the then-current financial market conditions. There can be no assurance that the cost or availability of future borrowings, if any, will not be impacted by recent or future capital market disruptions. Refer to Item 1A, "Risk Factors," in this Annual Report on Form 10-K for further discussion.

PSNH has outstanding $407.3 million of Pollution Control Revenue Bonds (PCRBs), one series of which, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as the result of failed auctions due to general market concerns. The interest rate on these PCRBs has been reset by formula under the applicable documents every 35 days and has ranged between 0.2 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for a current interest rate of 0.3 percent. We are not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents. In addition, CL&P has outstanding $423.9 million of PCRBs, one series of which, in the aggregate principal amount of $62 million, had a fixed interest rate for a five-year period that expired on September 30, 2008. As a result of poor liquidity in the tax-exempt market, CL&P chose to acquire this series of PCRBs on October 1, 2008. These PCRBs, which mature in 2031, have not been retired and are being held temporarily by CL&P in a flexible interest rate mode with one-day resets. CL&P expects to remarket the PCRBs when market conditions improve.

We project that our cash capital expenditures will be approximately $880 million in 2009, which is significantly less than 2008. We also project that cash flows from operations after RRB payments will increase by approximately $82 million from 2008 to 2009 due to our southwest Connecticut transmission projects being reflected fully in rates in 2009, lower refunds of the previous year s overcollections, a $20 million retail rate increase at CL&P, and the absence in 2009 of the 2008 Con Edison settlement. Also, only one series of our bonds matures prior to 2012, which is Yankee Gas' $50 million that mature in the second quarter of 2009. Due to these factors, we expect to require significantly less debt financing in 2009 than in 2008 (approximately $400 million, including the $250 million issued by CL&P in February 2009, compared to $760 million in 2008). We also continue to expect an equity issuance of approximately $250 million to $300 million in mid-2009 (or earlier depending on market opportunities). The proceeds from these financings would be primarily used to repay short-term borrowings and fund our capital programs. We will monitor market conditions to determine the appropriate timing and amount of further 2009 financings.

Our regulated standard offer type contracts do not require us to post collateral. The regulated companies continue to solicit bids on wholesale power contracts, the collateral terms of which we expect to be consistent with existing contracts. In other regulated contracts that do contain collateral posting requirements, the counterparties are generally exposed to us at this time, and these counterparties have been posting the necessary collateral when required. As of December 31, 2008, PSNH had posted $75 million in related collateral in the form of LOCs with counterparties, as compared to $14 million at December 31, 2007.

An affiliate of Constellation Energy Group, Inc. (Constellation), whose credit ratings were downgraded in 2008 due to liquidity and other concerns, provides energy under CL&P s standard offer contracts. As of December 31, 2008, CL&P is not exposed to Constellation in terms of credit risk, and Constellation is performing on specific contracts. In the event of Constellation s default, CL&P would be required to provide standard offer type services directly to customers until a substitute supplier could be arranged. Any additional costs incurred by CL&P in such a case would be recoverable from customers. If Constellation were to default under existing contracts within the next 12 months, CL&P could be required to temporarily post additional collateral of between $15 million and $25 million with ISO-NE based on forward market prices as of December 31, 2008.

Our collateral requirements for Select Energy s few remaining wholesale contracts are modest as we continue to wind down this business. Select Energy s largest remaining contract does not contain any collateral posting requirements. In addition, we have not experienced any significant performance difficulties with suppliers on Select Energy s remaining sourcing contracts. Select Energy is required to post collateral, primarily with its New York Mercantile Exchange (NYMEX) broker, based on the market prices and status of its sourcing contracts. As of December 31, 2008, Select Energy had posted $26.3 million in related collateral, as compared to $18.9 million at December 31, 2007. Refer to "NU Enterprises Contracts - Counterparty Credit Risk" in this Management s Discussion and Analysis for further discussion.

At December 31, 2007 our pension plan funded ratio (pension plan assets divided by the accumulated pension plan benefit obligation) was 123 percent. Our pension plan has historically been well funded, and we have not been required to make a contribution to the plan since 1991. Due to the negative financial market conditions experienced in 2008, the fair value of our pension plan assets dropped by approximately $900 million to $1.56 billion as of December 31, 2008, and our plan s funded ratio is now 76 percent. Based on this 2008 plan year valuation and unless there is a change in current funding requirements, we will be required to make an estimated pre-tax contribution to the plan of approximately $150 million to meet minimum funding requirements. This contribution would be paid just prior to the 2009 federal income tax return filing, which will likely occur in the third quarter of 2010. No cash contributions to the plan will be required to be made in 2009.

For the 2009 pension plan year, it is likely that we will also be required to make a pension plan contribution unless there is a change in current funding requirements or a very significant recovery in the financial markets. Also, assuming that the pension plan assets earn the long-term rate of return of 8.75 percent and discount rates remain constant, we currently estimate that we could be required to make an additional pre-tax contribution for the 2009 plan year in 2010 of between $150 million and $200 million. Contributions for the 2009 plan year would be made quarterly beginning in the second quarter of 2010. If significant contributions for 2009 or future pension plan years are required and there is no change in regulatory recovery mechanisms, then there will likely be an impact on the timing and amount of our future debt and equity financings. The majority of our pension expense is included in rates charged to customers of our regulated companies.

Transmission Rate Matters and FERC Regulatory Issues

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

Transmission - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Schedule 21 - NU rate schedules to recover fees for transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The Schedule 21 - NU rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 100 percent of the CWIP that is included in rate base on the NEEWS projects discussed below. The Schedule 21 - NU rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and Schedule 21 - NU rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to customers. At December 31, 2008, the Schedule 21 - NU rates were in a total underrecovery position of $4.6 million ($3.8 million for CL&P), which will be collected from customers in mid-2009.

FERC ROE Decision: On March 24, 2008, the FERC issued a rehearing order confirming its initial decision setting the base ROE for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the ISO-NE Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million ($4.9 million for CL&P) in transmission segment earnings related to this order. This order has been appealed to the D.C. Circuit Court of Appeals by numerous state regulators and consumer advocates. The Court has set a schedule for briefing to conclude by the end of the second quarter of 2009. No date has been set for arguments.

On May 16, 2008, CL&P filed an application with the FERC to receive ROE incentives for its Middletown-Norwalk project and to seek a waiver of the "completed and on line" date of December 31, 2008 to earn incentives, pursuant to the FERC s March 24, 2008 order on rehearing. Alternatively, we requested the FERC to find that this project met the nexus test requirements for incentives under FERC s guidelines for new projects, and requested an additional 50 basis point adder for advanced technology used in the project.

The FERC subsequently granted the waiver request and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also found that the project met the nexus test and granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project, ordering us to file more details regarding the advanced technology. The 50 basis point adder results in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent, which represents the overall ROE limit established by the FERC. Certain state regulators and municipal utilities sought rehearing, which were denied by the FERC, and Connecticut state regulators have since taken an appeal to the D.C. Circuit Court of Appeals. A schedule for the appeal has not yet been set. The technology adder increases CL&P's annual earnings beginning in 2009 by approximately $0.9 million.

On August 18, 2008, CL&P made a compliance filing with the FERC detailing the costs associated with the underground cables and supporting facilities of the Middletown-Norwalk project, which qualified as advanced technology. On September 8, 2008, the DPUC

41

filed a motion to reject and protest our compliance filing, stating we did not provide sufficient information. There is no specific deadline for the FERC to respond to this motion. Our response to the protest has been filed at the FERC.

NEEWS Incentives: On November 17, 2008, the FERC issued an order granting incentives and rate amendments to National Grid USA and us for the NEEWS projects. The approved incentives include:

- An ROE of 12.89 percent, representing an incentive of 125 basis points, 25 basis points lower than requested;
- 100 percent inclusion of prudently incurred CWIP in rate base; and
- Full recovery of prudently incurred costs if NEEWS, or any portion thereof, is cancelled as a result of factors beyond NU's or National Grid USA's control.

Our share of NEEWS is estimated to cost $1.49 billion, and we received incentives on a portion of the transmission upgrades with a current estimated cost to NU of $1.41 billion. Several parties have sought rehearing of the FERC order granting incentives for NEEWS, which have not yet been acted on by the FERC.

Legislative Matters

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

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

Massachusetts passed legislation in July 2008 that did not set an auction clearing price threshold for RGGI auctions. This law requires 80 percent of RGGI auction proceeds to be allocated to utility energy efficiency and demand response programs. Because WMECO does not own any generation assets, it is not required to acquire any CO_2 allowances; however, CO_2 allowance costs will likely be included in wholesale rates charged to WMECO in standard offer type contracts.

New Hampshire passed legislation in June 2008 that set an auction clearing price threshold of $6 per CO_2 allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs.

The first regional auction of RGGI CO_2 allowances took place on September 25, 2008. At the auction, more than 12.5 million CO_2 allowances were sold at the clearing price of $3.07 per CO_2 allowance. The second regional auction was held on December 17, 2008, and more than 31.5 million allowances were sold at a clearing price of $3.38 per CO_2 allowance. Auctions are scheduled for March, June, September and December 2009.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO_2 per year after taking into account the operation of PSNH s Northern Wood Power wood-burning generating plant, which under the RGGI formula, decreased PSNH s responsibility for reducing fossil-fired CO_2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO_2 allowances per year for PSNH s fossil fueled generating plants during the 2009 to 2011 compliance period. These banked CO_2 allowances will initially comprise approximately one-half of the yearly CO_2 allowances required for PSNH s generating plants to comply with RGGI, and such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing CO_2 allowances at auction or in the market and has purchased allowances in the first two auctions. The cost of complying with RGGI requirements is recoverable from PSNH customers.

New Hampshire:

2008 Legislation: In July 2008, New Hampshire passed a law establishing a transmission commission responsible for developing a proposal to expand the electric transmission system in northern New Hampshire to encourage the development of new renewable generation sources. On December 1, 2008, the transmission commission submitted its progress report, which concluded that New Hampshire should continue to pursue the upgrade of transmission capacity in its northern region to allow development of its native renewable energy resources. Also, the transmission commission should continue to pursue both local and regional cost allocation issues related to the transmission expansion. The northern New Hampshire region has the potential for over 500 MW of new renewable resources. PSNH has included $130 million in its 2009 to 2013 capital plan for transmission upgrades in this region, which assumes that these projects are built and that a cost allocation solution can be agreed to by relevant parties.

In July 2008, New Hampshire passed a law authorizing rate recovery by electric public utilities of investments made in distributed energy resources up to 5 MW, such as renewable energy generation. The total investment is limited to resources having a capability equal to 6 percent of a distribution utility s peak load. PSNH has not yet included any distributed energy resource investment opportunities in its capital expenditure plans.

Massachusetts:

2008 Legislation: As referenced above, in July 2008, Massachusetts enacted "The Green Communities Act of 2007." Aimed at increasing energy efficiency (EE) and the use of renewable resources in the state, the Act contains many provisions important to the state s utilities. In addition to adopting RGGI requirements, the Act:

.

Removes the cap on utility expenditures for EE and demand response (DR). Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;

.

Requires utilities to sign long-term contracts for renewable resources;

.

Allows each utility to own and operate up to 50 MW of solar generation;

.

Requires utilities to file a plan with the DPU for a smart grid pilot; and

.

Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

By April 30, 2009, WMECO is required to prepare a three-year EE and DR investment plan related to the cost of EE and DR programs established by the Act for review by the Energy Efficiency Council and, ultimately, the DPU. Under the Act, utilities are authorized to own up to 50 MW of solar generating facilities, if part of a DPU approved plan. WMECO filed a program with the DPU on February 12, 2009 providing for a three-phase program with DPU authorization prior to each phase. The initial phase calls for 6 MW to be installed at eight host sites in WMECO's service territory upon receipt of DPU approval. This phase of the project is expected to be completed as early as 2010 at a cost of approximately $42 million. The second phase includes an additional 9 MW extending through 2012, and the third and final phase could increase total capacity to the 50 MW maximum. The DPU has six months to issue a decision on WMECO's plan. WMECO is otherwise precluded from making new generation investments, but has not yet included any solar generation investment opportunities in its capital expenditure plans.

Corporate Excise Tax: On July 3, 2008, Massachusetts amended its corporate excise tax provisions, which are effective for tax years beginning on or after January 1, 2009. Companies must account for the impact of income tax law changes in the period that includes the enactment date of the law change. As a result, WMECO recorded an estimate of the impact of the new legislation as a $11.9 million decrease to deferred tax liabilities and a decrease to regulatory assets on its consolidated balance sheet as of December 31, 2008.

Regulatory Developments and Rate Matters

Regulated Distribution Companies: We are currently evaluating the rate case strategies of our distribution companies. Based on 2008 earnings, cost trends, sales trends and the impact of the December 11, 2008 ice storm, it is probable that PSNH will file a distribution rate case in 2009 seeking temporary rates effective by July 1, 2009, and permanent rates effective by July 1, 2010. CL&P has determined that it will not file a distribution rate case in mid-2009. CL&P will continue to consider the possibility of filing a rate case later in 2009 or in 2010, based on the economic, political and regulatory climate in Connecticut. In response to the July 2008 rate decoupling decision in Massachusetts, WMECO notified the DPU in September 2008 that it intends to file a distribution rate case seeking authority for full decoupling in mid-2010 to be effective in January 2011. We have no immediate plans to file a distribution rate case for Yankee Gas.

Regulated Companies Transmission Revenues - Retail Rates: A significant portion of our transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. Each of these companies has a retail transmission cost tracking mechanism as part of its rates, which allows them to charge their retail customers for transmission costs on a timely basis.

Forward Capacity Market: On December 1, 2006, a FERC-approved settlement agreement providing for an auction-based forward capacity market (FCM) mechanism was implemented and the payment of fixed compensation to generators through May 31, 2010 began. The first forward capacity auction concluded in early February 2008 for the capacity year of June 2010 through May 2011. The bidding reached the established minimum of $4.50 per kilowatt-month with 2,047 MW of excess remaining capacity, which resulted in an effective capacity price of $4.25 per kilowatt-month compared to the previously established price of $4.10 per kilowatt-month for the capacity year preceding June 2010. The second auction concluded on December 10, 2008 for the capacity year of June 2011 through May 2012. The bidding reached the established minimum of $3.60 per kilowatt-month with 4,755 MW of excess remaining capacity, which resulted in an effective capacity price of $3.12 per kilowatt-month. These costs are recoverable in all jurisdictions through the currently established rate structures.

Connecticut - CL&P:

Distribution Rates: On January 28, 2008, the DPUC issued a final decision in a rate case CL&P filed on July 30, 2007. As a result of the decision, CL&P implemented a $77.8 million annualized distribution rate increase effective February 1, 2008 and an incremental $20.1 million annualized distribution rate increase effective February 1, 2009.

Peaking Generation Filing: In 2007, Connecticut passed "An Act Concerning Electricity and Energy Efficiency" (Energy Efficiency Act). Among other provisions, the Energy Efficiency Act required electric distribution companies, including CL&P, to file proposals with the DPUC to build cost-of-service peaking generation facilities. In 2008, the DPUC selected three projects, none of which were proposals submitted by CL&P, to provide peaking generation totaling approximately 500 MW. CL&P entered into CfDs with the developers of the three selected peaking generation units (Peaker CfDs). The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. As directed by the DPUC, CL&P and UI entered into a cost sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P s portion of the costs and benefits will be paid by or refunded to its customers.

Renewable Energy Contracts: In 2008, pursuant to Connecticut's "Act Concerning Energy Independence," (Energy Independence Act), CL&P signed five contracts, and UI signed two contracts each to purchase energy, capacity and renewable energy credits from planned renewable energy plants, including biomass and fuel cell projects approved by the DPUC, comprising a total of 109 MW of capacity. CL&P signed one contract with a biomass project in 2007 to purchase 15 MW of its output. Purchases under the contracts are scheduled to begin between 2009 and 2011 and will extend for periods ranging from 15 to 20 years. As directed by the DPUC, CL&P and UI have also signed a sharing agreement under which they will share the costs and benefits of these contracts, with 80 percent to CL&P and 20 percent to UI. On January 16, 2009, the DPUC issued a draft decision selecting two additional renewable energy projects for a total of 6 MW with which CL&P or UI will sign similar contracts. The DPUC s final decision on these projects is scheduled for March 11, 2009. Additional projects are expected to be selected by the DPUC to achieve a total of 150 MW of renewable energy sources in Connecticut in accordance with the Energy Independence Act. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

AMI Filing: On December 19, 2007, the DPUC issued a final decision on CL&P s compliance plan that requires a pilot program to test customer interest in, and response to, peak-time based rates and technical capabilities of an advanced metering infrastructure (AMI). On May 2, 2008, the DPUC approved CL&P's revised pilot plan, which was subsequently modified to provide for a summer 2009 rate pilot supported by meters for 3,000 voluntary rate pilot customers. The restriction of meters to only rate pilot participants decreased the required number of meters from 10,000 to the current 3,000. The rate pilot customer enrollment campaign began in November 2008. CL&P is required to submit a report on the customer response to the pilot, including technical capabilities of AMI meters and customer response to peak-time based rates by December 1, 2009. The estimated incremental cost of the program currently has a range of $10.6 million to $13 million. The incremental costs associated with the pilot are authorized to be recovered from customers, initially through CL&P s FMCC. The non-incremental costs are projected to be less than $2 million.

FMCC Filing: In September 2008, the DPUC approved CL&P s semi-annual FMCC filing, which reconciled actual FMCC revenues and charges (including Energy Independence Act charges), and generation service charge (GSC) revenues and expenses for the full year period January 1, 2007 through December 31, 2007, and that identified a total overrecovery of $105.4 million at December 31, 2007. The majority of this overrecovery was returned to customers in 2008 through credits included in 2008 rates that were determined in separate rate proceedings. On August 5, 2008, CL&P filed with the DPUC its semi-annual FMCC filing for the period January 1, 2008 through June 30, 2008. This filing identified a net overrecovery totaling $30.9 million including the remaining unamortized overrecovery from 2007. In December 2008, the DPUC issued a final decision covering this period that approved all costs as filed.

On February 6, 2009, CL&P filed with the DPUC its semi-annual FMCC filing for the year ended December 31, 2008, which identified an underrecovery totaling approximately $31.9 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet. A decision schedule has not yet been set at this time. We do not expect the outcome of the DPUC's review of this filing to have a material adverse effect on CL&P's net income, financial position or cash flows.

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under Last Resort Service (LRS) rates. Effective January 1, 2009, the DPUC approved an increase to CL&P's total average SS rate of approximately 2.4 percent and a decrease to CL&P's total average LRS rate of approximately 5.9 percent. The energy supply portion of the total average SS rate increased from 11.852 cents per KWH to 12.316 cents per KWH. The energy supply portion of the total average LRS rate decreased from 12.667 cents per KWH to 11.738 cents per KWH. Effective April 1, 2009, the DPUC approved a decrease to CL&P s total average LRS rate of approximately 22 percent, which was a result of the energy supply portion decreasing to 8.207 cents per KWH from January 1, 2009. CL&P is fully and timely recovering the costs of its SS and LRS services.

CTA and SBC Reconciliation: On March 31, 2008, CL&P filed with the DPUC its 2007 Competitive Transition Assessment (CTA) and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying consolidated balance sheet. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet. On December 3, 2008, the DPUC issued a final decision in this docket that approved the 2007 CTA and SBC reconciliation with minor modifications. The decision referred to a potential change in the CTA rate effective January 1, 2009, when new rates were to be determined for all CL&P rate components. By letter dated December 23, 2008, the DPUC approved CL&P s recommendation to slightly decrease the base CTA rate and to establish a separate CTA refund credit beginning January 1, 2009. The CTA refund credit is intended to return to customers over a twelve month period a projected 2008 CTA overrecovery of $46.2 million, plus $1.8 million of incremental distribution revenues attributable to accelerating CL&P s previously allowed 2009 distribution rate increase from a start date of February 1, 2009 to January 1, 2009. The DPUC also approved an increase in the SBC rate to bill an additional $11.7 million in 2009, which should enable CL&P to fully recover 2009 SBC expenses plus expenses that were underrecovered in prior periods.

Transmission Adjustment Clause: On June 16, 2008, CL&P filed a transmission adjustment clause (TAC) with the DPUC requesting an increase in its retail transmission rate effective July 1, 2008 to collect $67.9 million of additional revenues over the second half of the year. The increase in the TAC was attributable to the additional investment in regional transmission reliability projects. The DPUC approved CL&P's filing on June 25, 2008. On December 8, 2008, CL&P filed a TAC with the DPUC requesting no change to the retail transmission rate to be effective January 1, 2009, which covers the period January 1 through June 30, 2009. The DPUC approved CL&P s filing on December 23, 2008.

Procurement Fee Rate Proceedings: In prior years, CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its transition service procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. On January 15, 2009, the DPUC issued a final decision in this docket reversing its December 2005 draft decision and stated that CL&P was not eligible for the procurement incentive compensation for 2004. A $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers has been established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

Customer Service and Metering Dockets: In 2008, the DPUC issued final decisions in a docket examining the manner of operation and accuracy of CL&P's electric meters and in a docket investigating CL&P billing errors involving approximately 2,000 customers on time of use rates. In the metering docket the DPUC did not fine CL&P, but the metering decision held that possibility open if CL&P fails to meet benchmarks to be established in the docket. The decision in the time of use docket disallowed recovery from customers of the incremental costs associated either directly or indirectly with the billing errors. These incremental costs are not material and have been expensed as incurred.

2008 Management Audit: On August 18, 2008, a consulting firm hired by the DPUC began an on-site management audit of CL&P, which is required to be conducted every six years by statute and requires a diagnostic review of all functions of the company. The audit has been completed, and a final audit report is scheduled to be filed with the DPUC in the first quarter of 2009. We do not expect a material impact to CL&P's financial position or results of operations from results of this audit.

Connecticut-Yankee Gas:

Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas PGA clause charges and required an audit of previously recovered PGA revenues of approximately $11 million associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund approximately $5.8 million in previous recoveries to its customers. The $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of Yankee Gas.

New Hampshire:

Merrimack Clean Air Project: In 2006, the New Hampshire legislature enacted legislation requiring PSNH to reduce the mercury emissions from its coal-fired stations by at least 80 percent through the installation of wet scrubber technology at its Merrimack Station in Bow, New Hampshire no later than July 1, 2013. Following an August 2008 announcement by PSNH that the cost of this installation would be increasing from the original estimate of $250 million to $457 million, the New Hampshire Public Utilities Commission (NHPUC) opened an inquiry to determine its authority to find whether the project is in the public interest. On September 19, 2008, the NHPUC ruled that its authority is limited to determining at a later time the prudence of the costs of complying with the requirements of the scrubber legislation. In October 2008, several parties filed motions with the NHPUC requesting a reconsideration of its ruling. On November 12, 2008, the NHPUC issued an order denying the motions for rehearing. On December 11, 2008, several parties involved in the filing of the October 2008 motion for rehearing filed an appeal with the New Hampshire Supreme Court requesting that the Court overturn the NHPUC's finding that it lacked present authority over this matter. The Supreme Court has indicated that it will hear this appeal, but has not yet issued a schedule for oral arguments. PSNH has begun site work for this project and has capitalized approximately $27.5 million as of December 31, 2008. While PSNH does not expect the outcome of this appeal to adversely impact its ability to recover incurred costs from customers, should the Clean Air Act project be canceled for any reason, resulting contract cancellation payments and termination costs would likely amount to a substantial portion of the approximately $250 million of contractual commitments expected to be entered into by March 31, 2009. The actual total would depend on the timing of a cancellation, if it were to occur, and related negotiations with vendors.

Delivery Service Rates: On January 1, 2008, PSNH s distribution rates increased by approximately $3 million annually, pursuant to the NHPUC s May 2007 approval of PSNH s distribution and transmission rate case settlement agreement with NHPUC staff and the New Hampshire Office of Consumer Advocate. On July 1, 2008, PSNH s distribution rates decreased by $0.4 million annually. This amount consisted of a $3.4 million rate reduction related to the full recovery of a rate differential recoupment, offset by an annual increase of $3 million for additional funding of the Major Storm Costs Reserve (MSCR) for a two-year period effective July 1, 2008 to eliminate a negative balance in the MSCR and restore the intended reserve level of $1 million.

ES and SCRC Reconciliation and Rates: On May 1, 2008, PSNH filed its 2007 default energy service (ES) and stranded cost recovery charge (SCRC) reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation activities. During 2007, ES and SCRC revenues exceeded ES and SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a

regulatory liability to be refunded to customers. On November 19, 2008, PSNH and the NHPUC Staff submitted a settlement agreement that resolved all outstanding issues. The NHPUC issued an order dated January 16, 2009 that accepted the settlement as filed. The settlement agreement and subsequent order did not have a material adverse impact on PSNH's financial position or results of operations. PSNH expects to file its 2008 ES and SCRC reconciliation with the NHPUC by May 1, 2009. We do not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's financial position or results of operations.

On June 27, 2008, the NHPUC issued orders increasing the ES rate from 8.82 cents per KWH to 9.57 cents per KWH and lowering the SCRC rate from 0.72 cents per KWH to 0.65 cents per KWH, effective from July 1, 2008 through December 31, 2008. In December 2008, the NHPUC issued orders that increased the ES rate to 9.92 cents per KWH and the SCRC rate to 0.98 cents per KWH. These rates will be effective from January 1, 2009 through December 31, 2009.

TCAM Reconciliation and Rates: On May 13, 2008, PSNH filed a July 1, 2007 through June 30, 2008 transmission cost adjustment mechanism (TCAM) reconciliation and a projected TCAM rate to be billed effective July 1, 2008 and continuing through June 30, 2009. Under the terms of an NHPUC rate order issued on June 27, 2008, PSNH s TCAM rate was increased from 0.752 cents per KWH to 0.935 cents per KWH, effective July 1, 2008.

Major Storm Costs Reserve: On December 11, 2008, a major ice storm struck portions of New England, severely damaging PSNH s distribution system. This was the most severe ice storm in PSNH s history. Of the 440,000 New Hampshire homes and businesses that lost power, 322,000 were served by PSNH. Restoration operations commenced on December 11, 2008 and were substantially completed by December 25, 2008. PSNH utilized its own line crews, local contractors, line crews from other NU subsidiaries and numerous other line crews from the eastern United States and Canada.

The operating cost of storm restorations that meet a NHPUC specified criteria are funded through the MSCR. Capital costs for any storm work are charged to property, plant and equipment and recovered through the normal distribution ratemaking process. As the December 2008 ice storm met the MSCR criteria, $62.7 million of total estimated repair costs of $75 million associated with this storm were charged to the MSCR at December 31, 2008. PSNH intends to recover these costs as part of its next delivery rates proceeding with the NHPUC. Out of the remaining total storm costs incurred through December 31, 2008, $6.5 million of non-incremental costs has been expensed and $5.6 million has been capitalized to plant and equipment. PSNH expects to recognize an additional $10 million in 2009 when the weather is warmer and additional clean-up and repairs can be performed. We carry $15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to PSNH to reduce the amount of deferred or expensed storm costs. The NHPUC scheduled public hearings in March and April of 2009 as part of its review of state and utility operational responses to the storm. The costs of the December 11, 2008 storm did not have a material impact on PSNH's 2008 net income.

Renewable Portfolio Standards: On May 11, 2007, Governor Lynch signed into law the "Renewable Energy Act," establishing renewable portfolio standards (RPS) that requires annual increases in the percentage of electricity with direct ties to renewable sources sold to New Hampshire retail customers. The renewable sourcing requirements began in 2008 and increase each year to reach 23.8 percent in 2025. PSNH plans to meet these standards, in part, through the purchase of renewable energy certificates (RECs) from qualified renewable energy resources. For each MWH of energy produced from a qualifying resource, the producer will receive one REC. Energy suppliers, like PSNH, will purchase these RECs from the producers and will use them to satisfy the RPS requirements. To the extent that PSNH is unable to purchase sufficient RECs, it will be required to make up the difference between the RECs purchased and its total obligation by making an alternative compliance payment (ACP) for each REC requirement for which PSNH is deficient. The $8.7 million in 2008 costs for the RPS obligation did not impact earnings, as these costs are being recovered by PSNH through its ES rates.

Massachusetts:

Distribution Rates: On January 1, 2008, WMECO s distribution rates increased by $3 million annually as approved by the DPU in December 2006. WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. On December 29 and 30, 2008, the DPU approved WMECO s proposed rate changes effective January 1, 2009. The rate changes were made in accordance with WMECO s various tracking mechanisms. The overall impact on customers bills was a 0.5 percent increase for residential customers, a 2 percent decrease for small commercial and industrial customers, and a 3 percent decrease for medium and large commercial and industrial customers.

Basic Service Rates: Effective July 1, 2008, the rates for basic service customers increased due to the rise in the cost of energy reflected in WMECO's basic service solicitations. Basic service rates for residential customers increased from 10.8 cents per KWH to 12.1 cents per KWH, small commercial and industrial customers increased from 11.5 cents per KWH to 12.8 cents per KWH and rates for medium and large commercial and industrial customers increased from 10.5 cents per KWH to 14.6 cents per KWH. Effective October 1, 2008, the rates for WMECO's medium and large commercial and industrial basic service customers decreased from 14.6 cents per KWH to 11.1 cents per KWH due to the decline in the cost of energy, as reflected in its basic service solicitations. Effective January 1, 2009, the rates for all basic service customers decreased due to the decline in the cost of energy, as reflected in WMECO's basic service solicitations. Basic service rates for residential customers decreased from 12.1 cents per KWH to 11.8 cents per KWH, small commercial and industrial customers decreased from 12.8 cents per KWH to 12.1 cents per KWH and rates for medium and large commercial and industrial customers decreased from 11.1 cents per KWH to 10.2 cents per KWH.

Transition Cost Reconciliations: On June 20, 2008, the DPU issued its final decision on WMECO s 2005 and 2006 transition cost reconciliations, which resulted in a pre-tax charge of $1.6 million to WMECO s 2008 consolidated statements of income. The DPU ordered WMECO to use a ROE of 11 percent, and not the allowed ROE of 9.85 percent in 2005 and 2006, for purposes of calculating

carrying cost credits for customers on the stranded cost deferrals. In addition, the DPU ordered WMECO not to combine certain overrecoveries and underrecoveries but instead to keep them separate and to calculate carrying costs on certain balances using a ROE of 11 percent and to use customer deposit rates on other balances. The impacts of this order on WMECO's calculations of the 2007 and year to date 2008 transition cost reconciliations were recorded in the second quarter of 2008.

Decoupling Decision: On July 16, 2008, the DPU issued a decision in its decoupling generic docket requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. The decision rejected calls for partial decoupling or decoupling by rate design in favor of full decoupling by rate class. Actual revenues are to be reconciled to target revenues, as established in litigated rate cases, on an annual basis. Adjustments per the reconciliation will be made to the distribution component of rates. The decision also determined that the DPU will honor existing long-term rate plans, performance-based regulation plans and settlements. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal to fully decouple distribution revenues from KWH sales.

Service Quality Performance Assessment: As part of the December 2006 rate case settlement agreement approved by the DPU, WMECO became subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred are paid to customers through a method approved by the DPU. WMECO will likely be required to pay an assessment charge for its 2008 reliability performance against the metrics established for 2008, primarily as a result of significant storm activity. WMECO has performed at target for other non-storm related reliability metrics. WMECO will file its 2008 SQ results and assessment calculation with the DPU in March 2009. In 2008, WMECO recorded an estimated pre-tax charge and a regulatory liability of approximately $1.3 million for this assessment.

Storm Costs Reserve: The December 11, 2008 ice storm also impacted areas served by WMECO. As this storm met the storm costs reserve criteria approved in WMECO's last distribution rate case settlement, $11.3 million of the total $13.8 million estimated repair costs associated with this storm were recognized as a deferred asset at December 31, 2008. WMECO expects to begin recovery of these costs in its next distribution rate proceeding. Out of the remaining total storm costs, $1.4 million has been expensed, including a significant portion of non-incremental costs, and $1.1 million has been capitalized to plant and equipment. We carry $15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to WMECO to reduce the amount of deferred or expensed storm costs. The DPU has opened a formal docket to review storm restoration efforts by the state's utilities and held public hearings in February 2009. The costs of the December 11, 2008 storm did not have a material impact on the 2008 earnings of WMECO.

Transfer of Transmission Assets: On December 15, 2008, the FERC approved the transfer of $4 million in transmission related assets of our wholly owned subsidiaries' HWP and HP&E to WMECO, which occurred on December 31, 2008. After certain routine regulatory filings, HWP and HP&E will no longer be FERC-regulated entities.

Contingent Matters:

The items summarized below contain contingencies that may have an impact on our net income, financial position or cash flows. See Note 7A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the consolidated financial statements for further information regarding these matters.

.

Transition Cost Reconciliation: On July 18, 2008, WMECO filed its 2007 transition cost (TC) reconciliation with the DPU, which compared TC revenue and revenue requirements. For the twelve months ended December 31, 2007, total TC revenues along with carrying charges exceeded TC revenue requirements by $2.6 million, which has been recorded as a regulatory liability on the accompanying consolidated balance sheets. A public hearing and procedural conference was held on November 20, 2008. On December 22, 2008, the Massachusetts Attorney General filed testimony on two topics: the deferred return and carrying charges on the Capital Project Scheduling List; and the recovery of Northeast Nuclear Company pension/postretirement benefits other than pension (PBOP) costs. WMECO filed rebuttal testimony on December 30, 2008. A hearing was held on January 29, 2009. The briefing period ended on February 26, 2009. There is no timeline for a DPU decision. We do not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.

.

C2 Prudency Audit: Pursuant to the decision in CL&P's 2007 rate case, the DPUC has hired a consulting firm to perform a prudency audit of certain costs incurred in the implementation of a new customer service system (C2) at CL&P. The audit began on December 1, 2008 and will be ongoing through early 2009, with a final report to the DPUC due March 31, 2009. The DPUC has stated its intentions to open a docket to review the findings of the audit after completion. We continue to believe that our C2 expenses were prudent and will be recovered in rates.

Deferred Contractual Obligations

We have decommissioning and plant closure cost obligations to Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC) and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including our electric utility subsidiaries. These companies recover these costs through state regulatory commission-approved retail rates. A summary of each of our subsidiary s ownership percentage in the Yankee Companies at December 31, 2008 is as follows:

	CYAPC	**YAEC**	**MYAPC**
CL&P	34.5%	24.5%	12.0%
PSNH	5.0%	7.0%	5.0%
WMECO	9.5%	7.0%	3.0%
Totals	49.0%	38.5%	20.0%

Our percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC, YAEC and MYAPC are currently collecting amounts that we believe are adequate to recover the remaining decommissioning and closure cost estimates for their respective plants. We believe CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. In December 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

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

The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, we believe that any net settlement proceeds we receive would be incorporated into FERC-approved recoveries, which would be passed on to our customers through reduced charges.

NU Enterprises Divestitures

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

Wholesale Marketing: During 2008 Select Energy continued to manage its remaining PJM power pool wholesale sales contract and its related supply contracts, which expired on May 31, 2008, and its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, and related supply contracts, that expires in 2013. These contracts are derivatives that have been marked to market through earnings. In addition to the NYMPA-related contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase and operate the output of a certain generating facility in New England through 2012. As a non-derivative contract, the fair value of the contract has not been reflected on the balance sheet, and the contract has not been marked to market.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business and paid $24.4 million in 2006 and $14.7 million in 2007 to the purchaser, which completed our obligation.

Competitive Generation Business: We completed the sale of NU Enterprises' competitive generation assets on November 1, 2006.

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

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, we provided various guarantees and indemnifications to the purchasers of those businesses. See Note 7F, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: On January 1, 2008, we implemented SFAS No. 157. For further information on SFAS No. 157, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the consolidated financial statements, and the "Critical Accounting Policies and Estimates" section of this Management s Discussion and Analysis.

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

	December 31,	
(Millions of Dollars)	**2008**	**2007**
Current wholesale derivative assets	$ -	$ 36.2
Long-term wholesale derivative assets	-	7.2
Current wholesale derivative liabilities	(14.5)	(64.9)
Long-term wholesale derivative liabilities	(49.4)	(72.5)
Portfolio position	$ (63.9)	$ (94.0)

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

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

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts at December 31, 2008 and 2007. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as historical experience with intramonth price volatility and bilateral contract prices in illiquid periods. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based upon a model. The model utilizes natural gas prices and a heat rate conversion factor to determine off-peak electricity prices for one New York routinely quoted hub zone for 2013. For the balance of hub zones, broker quotes for electricity prices are generally available on-peak through 2013 and off-peak through 2012.

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

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

(Millions of Dollars)	**Fair Value of Wholesale Contracts at December 31, 2008**							
Sources of Fair Value	**Maturity Less than One Year**		**Maturity of One to Four Years**		**Maturity in Excess of Four Years**		**Total Fair Value**	
Prices actively quoted	$	(10.1)	$	(7.3)	$	(1.2)	$	(18.6)
Prices provided by external sources		(2.7)		(21.2)		(10.0)		(33.9)
Model-based [1]		(1.7)		(6.7)		(3.0)		(11.4)
Totals	$	(14.5)	$	(35.2)	$	(14.2)	$	(63.9)

(1)

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

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

For the years ended December 31, 2008 and 2007, the changes in fair value of these derivative contracts are included in the table:

	Total Portfolio Fair Value	
	2008	2007
(Millions of Dollars)		
Fair value of wholesale contracts outstanding at the beginning of the year	$ (94.0)	$ (126.5)
Pre-tax effects of implementing SFAS No. 157 ($3.2 million after-tax) (1)	(6.1)	-
Contracts realized or otherwise settled during the year (2)	29.2	38.9
Change in unrealized gains/(losses) included in earnings	7.0	(6.4)
Fair value of wholesale contracts outstanding at the end of the year	$ (63.9)	$ (94.0)

(1)

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

(2)

The 2008 amount includes purchases, issuances and settlements of $24.2 million and realized intra-month gains of $5 million.

For further information regarding Select Energy's derivative contracts, see Note 3, "Derivative Instruments," to the consolidated financial statements.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to our continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. At December 31, 2008, approximately 99 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, and approximately one percent was collateralized. The bulk of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we have assessed as creditworthy. To date, this counterparty has met all of its contractual obligations.

Off-Balance Sheet Arrangements

Letters of Credit: PSNH has LOCs posted as collateral with counterparties and ISO-NE. At December 31, 2008, PSNH had $85 million in LOCs outstanding. In addition, Select Energy has a $2 million LOC posted at December 31, 2008.

Competitive Businesses: We have various guarantees and indemnification obligations outstanding on behalf of former subsidiaries in connection with the exit from our competitive businesses. See Note 7F, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding the maximum exposure and amounts recorded under these guarantees and indemnification obligations.

Enterprise Risk Management

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

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates, assumptions and at times difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact our financial position or results of operations. Our management communicates to and discusses with our Audit Committee of the Board of Trustees critical accounting policies and estimates. The following are the accounting policies and estimates that we believe are the most critical in nature. See Note 1, "Summary of Significant Accounting Policies," to our consolidated financial statements for further discussions of these policies and estimates as well as other accounting policies, estimates and assumptions used in the preparation of our consolidated financial statements.

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

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

HWP, a subsidiary of NU, continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial investigative and remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of December 31, 2008. The cumulative expense recorded to this reserve through December 31, 2008 was approximately $15.9 million, of which $13.9 million had been spent, leaving approximately $2 million in the reserve as of December 31, 2008.

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

At this time, we believe that the $2 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $2 million to $2.7 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2009.

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

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

Fair Value Measurements: We adopted SFAS No. 157 as of January 1, 2008. SFAS No. 157 defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). It establishes a framework for measuring fair value, using a three level hierarchy based upon the observability of inputs to the valuations. See Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the accompanying consolidated financial statements for further information.

As of January 1, 2008, we applied SFAS No. 157 to our regulated and unregulated companies derivative contracts that are recorded at fair value and to the marketable securities held in our supplemental benefit trust and WMECO s spent nuclear fuel trust. We have also applied SFAS No. 157 to valuations of investments in our pension and PBOP plans as of December 31, 2008. Implementing SFAS No. 157 for our marketable securities expanded our financial statement disclosures, but did not affect the recorded fair value of investments.

For the year ended December 31, 2008, we recorded a net after-tax reduction of earnings of $3.2 million as a result of applying SFAS No. 157 to derivative liabilities for Select Energy s remaining wholesale marketing contracts.

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

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

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

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

Many of our derivative contracts that are recorded at fair value are classified as Level 3 within the hierarchy and are valued using models that incorporate both observable and unobservable inputs. Contracts valued using models are classified according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, an item may be classified as Level 3 even though there may be some significant inputs that are readily observable.

Contracts are valued using models when quoted prices in active markets for the same or similar instruments are not available. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. The observable inputs into the valuation include contract purchase prices and future energy prices for the near term. Discounted cash flow valuations incorporate estimates of premiums or discounts, reflecting risk adjusted profit that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit risk.

Changes in fair value of the remaining wholesale marketing contracts of our unregulated businesses are recorded in fuel, purchased and net interchange power on the accompanying consolidated statements of income. For the year ended December 31, 2008, there were net unrealized gains of $4.3 million ($7 million pre-tax), related to the valuation of these contracts. There were net realized gains of $3 million ($5 million pre-tax) for the year ended December 31, 2008. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts We utilize judgments in estimated expected volumes that are dependent on a number of factors including options exercised, customer utilization, weather and availability of other power sources to our counterparty. The valuations of our derivative contracts are highly sensitive to changes in market prices of commodities. See Item 7a, "Quantitative and Qualitative Disclosures about Market Risk," included in this Annual Report on Form 10-K for a sensitivity analysis of how changes in the prices of commodities would impact earnings.

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

Total Level 3 derivative assets were 66 percent of our total assets measured at fair value, and Level 3 derivative liabilities were 91 percent of our total liabilities measured at fair value at December 31, 2008. A significant portion of our Level 3 derivative liabilities relate to the regulated company derivative contracts for which changes in fair value do not affect our earnings due to our use of regulatory accounting. Changes in fair value of these contracts are not material to our liquidity or capital resources because the costs and benefits of the contracts are recoverable from or refundable to customers on a timely basis.

Our regulated and unregulated business activities that result in the recognition of derivative assets create exposures to credit risk of energy marketing and trading counterparties. At December 31, 2008, we had $273.2 million ($245.8 million related to CL&P) of regulated company and NU parent derivative assets that are contracted with multiple entities, of which $125.5 million ($104.7 million related to CL&P) is contracted with investment grade entities, $4.6 million is contracted with a government-backed entity, $131.4 million related to CL&P is contracted with a non-rated subsidiary of an investment grade company and the remainder are contracted with multiple other counterparties. We consider the credit ratings of these companies in our valuation of derivative assets and we use published probability of default indices based on the credit ratings of the counterparties to discount the value of the derivative asset. Changes in our counterparties credit impact our ability to collect the derivative asset. Our derivative assets are primarily related to our regulated companies. Credit losses on regulated company contracts would not affect our earnings because these entities are cost-of-service regulated companies and costs of these contracts are recoverable from our customers. In addition, we consider our own credit rating in the valuation of derivative liabilities. Adjusting our unregulated derivative liabilities to incorporate our credit risk had an after-tax impact of $0.7 million on the fair value of our derivative liability and net income for the year ended December 31, 2008. Our regulated companies derivative assets and liabilities were also reduced to reflect the impact of our counterparties credit risk and our own credit risk on fair values, with no effect on net income.

NU has a policy of margining counterparties in the event that the fair value of a derivative contract exceeds a pre-determined threshold. Depending on the credit rating of the counterparty, an unsecured credit line is granted to counterparties. In the event the fair value exceeds the unsecured credit line, NU requires cash collateral for those open positions. There are exceptions to this policy for contracts whose terms are determined by regulators.

We review and update our fair value hierarchy classifications on a quarterly basis. As of December 31, 2008, we hold $53.5 million of investment securities in our supplemental benefit trust for non-pension retirement benefits and $55.7 million of investment securities in our WMECO spent nuclear fuel trust. These investments are classified in Levels 1 and 2. Classification of an investment security or group of investment securities into Level 3 may occur if a significant amount of inputs to their valuation is no longer observable due to a decline in market activity or liquidity. We have assessed the impact of recently increasing market illiquidity on the valuation of our investments. Observable inputs remain available to value the classes of securities we own. We continue to monitor the liquidity of our securities and review our valuations to ensure proper classification within the fair value hierarchy.

We consider unrealized losses on investment securities in the trusts to be other than temporary by nature and recognize them as realized losses because investment decisions are made by our trustee and we do not have the ability to hold securities until unrealized losses are recovered. Therefore, unrealized losses incurred on our supplemental benefit trust are recorded as realized losses in our consolidated statements of income. In 2008, we recorded $9.2 million of after-tax unrealized losses incurred on our supplemental benefit trust in other income, net on the consolidated statement of income. These amounts were partially offset by $0.4 million of after-tax net realized gains on sales of investment securities. Losses related to the WMECO spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel obligation and do not impact earnings.

We believe that current market conditions were the key driver of losses recognized on our investment securities. As of December 31, 2008, our supplemental benefit trust invested in equity securities and investment grade fixed income securities (BBB- and above or equivalent). Our spent nuclear fuel trust invested in short-term investments and investment grade fixed income securities. We have $0.3 million of mortgage-backed and asset-backed securities collateralized by sub-prime debt or Alt-B debt held in the supplemental benefit trust and $0.2 million of mortgage-backed securities collaterized by Alt-A debt in the spent nuclear fuel trust. A significant portion of our mortgage-backed securities are U.S. Agency notes collateralized by residential mortgages. The underlying collateral of our corporate-asset backed securities includes residential home equity loans, auto and equipment loans, commercial mortgage-backed securities and credit card receivables.

For further information on derivative contracts and marketable securities, see Note 1E, "Summary of Significant Accounting Policies - Derivative Instruments," Note 3, "Derivative Instruments," and Note 9, "Marketable Securities," to the consolidated financial statements.

Pension and PBOP: Our subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all our regular employees. In addition to the Pension Plan, we also participate in the PBOP Plan to provide certain health care benefits, primarily medical and dental, and life insurance benefits to retired employees. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the resulting changes in benefit obligations, fair values of plan assets, funded status and net periodic expense could have a material impact on our financial position or results of operations.

Pre-tax periodic pension expense for the Pension Plan was $2.4 million, $17.4 million and $52.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. The pension expense amounts exclude one-time items such as Pension Plan curtailments and termination benefits. The pre-tax net PBOP Plan cost, excluding curtailments and termination benefits, was $36.2 million, $38.4 million and $50.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Long-Term Rate of Return Assumptions: In developing our expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, we evaluated input from actuaries and consultants, as well as long-term inflation assumptions and our historical 25-year compounded return of 11 percent. Our expected long-term rates of return on assets are based on certain target asset allocation assumptions. We believe that 8.75 percent is an appropriate aggregate long-term rate of return on Pension Plan and PBOP Plan assets (life assets and non-taxable health assets) and 6.85 percent for PBOP health assets, net of tax, for 2008. We will continue to evaluate these actuarial assumptions, including the expected rate of return, at least annually and will adjust the appropriate assumptions as necessary. The Pension Plan s and PBOP Plan s target asset allocation assumptions and expected long-term rates of return assumptions by asset category are as follows:

	At December 31,			
	Pension Benefits 2008 and 2007		Postretirement Benefits 2008 and 2007	
	Target Asset Allocation	**Assumed Rate of Return**	**Target Asset Allocation**	**Assumed Rate of Return**
Equity Securities:				
United States	40%	9.25%	55%	9.25%
Non-United States	17%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	2%	10.25%
Private	8%	14.25%	-	-
Debt Securities:				
Fixed income	25%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%
Real Estate	5%	7.50%	-	-

The actual asset allocations at December 31, 2008 and 2007 approximated these target asset allocations. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. For information regarding actual asset allocations, see Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and postretirement benefit payments. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility. As a result of these risks, it is reasonably probable that the market values of investment securities could increase or decrease in the near term, resulting in a material impact on the value of our pension assets. Increases or decreases in the market values could materially affect the current value of the trusts and the future level of pension and

other postretirement benefit expense. The current conditions in the credit market could negatively impact the assets in our trusts, but at this time we still believe that the 8.75 percent rate and the 6.85 percent rate for respective Pension and PBOP Plan assets are appropriate long-term rate of return assumptions.

Actuarial Determination of Expense: Pension and PBOP expense consists of the service cost and prior service cost determined by our actuaries, the interest cost based on the discounting of the obligations and the amortization of the net transition obligation, offset by the expected return on plan assets. Pension and PBOP expense also includes amortization of actuarial gains and losses, which represent differences between assumptions and actual or updated information.

We calculate the expected return on plan assets by applying our assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the calculated expected return and the actual return based on the change in the fair value of assets during the year. At December 31, 2008, total investment losses to be reflected in the four-year rolling average of plan assets over the next four years were $672.3 million and $73.9 million**,** for the Pension Plan and the PBOP Plan, respectively. As these asset losses are reflected in the average plan asset fair values, they will be subject to amortization with other unrecognized gains/losses. The Plans currently amortize unrecognized gains/losses as a component of pension and PBOP expense over approximately 12 years, which were the average future service period of the employees at December 31, 2008.

At December 31, 2008, the net actuarial loss subject to amortization over the next 12 years was $237.2 million and $104.9 million for the Pension Plan and PBOP Plan, respectively, which excludes the $672.3 million and $73.9 million of previous investment losses not currently reflected in the calculation of the fair value of Pension Plan and PBOP Plan assets, respectively.

Discount Rate: The discount rate that is utilized in determining future pension and PBOP obligations is based on a yield-curve approach where each cash flow related to the Pension Plan or PBOP Plan liability stream is discounted at an interest rate specifically applicable to the timing of the cash flow. The yield curve is developed from the top quartile of AA rated Moody s and S&P s bonds without callable features outstanding at December 31, 2008. This process calculates the present values of these cash flows and calculates the equivalent single discount rate that produces the same present value for future cash flows. The discount rates determined on this basis are 6.89 percent for the Pension Plan and 6.90 percent for the PBOP Plan at December 31, 2008. Discount rates used at December 31, 2007 were 6.60 percent for the Pension Plan and 6.35 percent for the PBOP Plan.

Forecasted Expenses and Expected Contributions: Due to the effect of the unrecognized actuarial gains/losses and based on the long-term rate of return assumptions and discount rates as noted above as well as various other assumptions, we estimate that expected forecasted expense for the Pension Plan and PBOP Plan will be $40.3 million and $37.3 million, respectively, in 2009, which is included in our guidance.

Future actual Pension and PBOP expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plans and amounts capitalized. We expect to continue with our policy to contribute to the PBOP Plan at the amount of PBOP expense, excluding curtailments and special benefit amounts. Beginning in 2007, we made additional contributions to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amounted to $3.7 million in 2008 and is estimated to be $3.4 million in 2009.

We have not contributed to the Pension Plan since 1991. However, as discussed below, the fair value of Pension Plan assets declined significantly during 2008. This decline, and the resulting asset level compared to the Pension Plan obligation, resulted in a required pre-tax contribution for the 2008 Pension Plan year that we currently estimate to be $150 million (assuming there is no change in current funding requirements). This contribution would be made just prior to the filing of the 2009 federal income tax return, which will likely be filed in the third quarter of 2010.

For the 2009 pension plan year, it is likely that we will also be required to make a contribution unless there is a change in current funding requirements or a very significant recovery in the financial markets. Also assuming that the pension plan assets earn the long-term rate of return of 8.75 percent and discount rates remain constant, we could be required to make an additional pre-tax contribution for the 2009 plan year in 2010 of between $150 million and $200 million. Contributions for the 2009 plan year would be made quarterly starting in the second quarter of 2010.

Sensitivity Analysis: The following represents the increase/(decrease) to the Pension Plan s and PBOP Plan s reported cost as a result of a change in the following assumptions by 50 basis points (in millions):

	At December 31,							
	Pension Plan Cost				Postretirement Plan Cost			
Assumption Change		**2008**		**2007**		**2008**		**2007**
Lower long-term rate of return	$	11.8	$	11.1	$	1.3	$	1.1
Lower discount rate	$	11.6	$	12.9	$	1.4	$	1.4
Lower compensation increase	$	(6.2)	$	(6.9)		N/A		N/A

Plan Assets: The fair value of the Pension Plan assets decreased by $902.6 million to $1.56 billion at December 31, 2008. This decrease includes benefit payments of $127.6 million in 2008. The Projected Benefit Obligation (PBO) for the Pension Plan increased by $40.8 million to $2.3 billion at December 31, 2008. These changes have changed the funded status of the Pension Plan on a PBO

basis from an overfunded position of $202.5 million at December 31, 2007 to an underfunded position of $740.9 million at December 31, 2008. The PBO includes expectations of future employee compensation increases.

The accumulated benefit obligation (ABO) of the Pension Plan was approximately $490 million greater than Pension Plan assets at December 31, 2008 and approximately $454 million less than Pension Plan assets at December 31, 2007. The ABO is the obligation for employee service and compensation provided through December 31, 2008.

The value of PBOP Plan assets has decreased by $82.5 million to $195.6 million at December 31, 2008. The benefit obligation for the PBOP Plan has decreased by $23.6 million to $436 million at December 31, 2008. These changes have increased the underfunded status of the PBOP Plan on an accumulated projected benefit obligation basis from $181.5 million at December 31, 2007 to $240.4 million at December 31, 2008. We have made a contribution each year equal to the PBOP Plan s postretirement benefit cost, excluding curtailment and termination benefits.

The Pension Plan assets include certain investments that are not regularly priced in an active market. These investments include private equity interests and real estate fund assets, comprising approximately 15 percent of total plan assets as of December 31, 2008. In determining the fair value of Pension Plan assets as of December 31, 2008, we obtained the most recent financial statements and requested updated values as of December 31st from the fund managers in order to obtain the best possible estimate of fair values. For the private equity and many real estate funds, the fund managers were able to provide year-end estimates of value. After discussion with various fund managers, we obtained information about conditions in the real estate markets and concluded on appropriate real estate fund values where manager estimates had not been given. The valuation of these investments requires significant judgment. These values reflect management's best estimate as of December 31, 2008.

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 8.5 percent for 2008, decreasing one half percentage point per year to an ultimate rate of 5 percent in 2015. The effect of increasing the health care cost trend by one percentage point would have increased service and interest cost components of the PBOP Plan cost by $1 million in 2008 and $1 million in 2007. Changes in the long-term health care cost trend assumption could have a material impact on our financial position or results of operations.

Goodwill and Intangible Assets: SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill balances be reviewed for impairment at least annually by applying a fair value-based test. The testing of goodwill for impairment requires us to use estimates and judgment. We have selected October 1st of each year as the annual goodwill impairment testing date. Management reviews triggering events as defined under SFAS No. 142 throughout the year and has determined that no triggering events occurred in 2008 that would have required interim testing before or after October 1st. 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 of the goodwill. If goodwill is deemed to be impaired, it is written off in the current period to the extent it is impaired.

We completed our impairment analysis as of October 1, 2008 for the Yankee Gas goodwill balance of $287.6 million and determined that no impairment exists. In performing the required impairment evaluation, we estimated the fair value of the Yankee Gas reporting unit and compared it to the carrying amount of the reporting unit, including goodwill. We estimated the fair value of Yankee Gas using discounted cash flow methodologies and an analysis of comparable companies or transactions. We review the outcome of each of the approaches annually and weight them appropriately to determine the fair value of Yankee Gas. This analysis requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples of comparable companies.

We determined the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the ROE is calculated using risk-free rates, stock premiums and a beta representing Yankee Gas' volatility relative to the overall market. The discount rate fluctuates from year to year as it is based on external market conditions. In 2008, the discount rate decreased because the risk-free rate and the beta were much lower in 2008 than in 2007 due to the current market conditions and the stability of the natural gas industry in this market. All of these assumptions are critical to the estimate and can change from period to period.

Updates to these assumptions in future periods, particularly changes in discount rates, could result in future impairments of goodwill. Although our evaluations since adopting SFAS No. 142 have not resulted in impairment, the estimated fair value of Yankee Gas is sensitive to changes in assumptions. For example, if the risk adjusted discount rate increased from approximately 5.95 percent to approximately 6.52 percent or the merger multiple of comparable companies decreased from approximately 10.5 to approximately 9.7 and the weighting of our valuation methodologies remained the same, then the estimated fair value of Yankee Gas would be lower than its carrying value.

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

Part of the annual process in making adjustments to these estimates, as needed, is a reconciliation of the actual tax positions and amounts included on our income tax returns as filed in the fall of each year for the previous tax year to the estimates or provisions made during the income tax estimation process described above. In the third quarter of 2008, the impact of these return to provision adjustments on income tax expense was benefits of $3.2 million and $1 million for NU and CL&P, respectively.

A reconciliation of expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in Note 1H, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial statements.

Effective on January 1, 2007, we implemented Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN 48 applies to all income tax positions previously filed in a tax return and income tax positions expected to be taken in a future tax return that have been reflected on our balance sheets. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties.

The determination of whether a tax position meets the recognition threshold under FIN 48 is based on facts, circumstances and information available to us. Once a tax position meets the recognition threshold, the tax benefit is measured using a cumulative probability assessment. Assigning probabilities in measuring a recognized tax position and evaluating new information or events in subsequent periods could change previous conclusions used to measure the tax position estimate. This requires significant judgment. New information or events may include tax examinations or appeals, developments in case law, settlements of tax positions, changes in tax law and regulations, rulings by taxing authorities and statute of limitation expirations. Such information or events may have a significant impact on our net income, financial position and cash flows.

Derivative Accounting: Certain regulated companies contracts for the purchase or sale of energy or energy related products are derivatives, along with all but one of Select Energy s remaining wholesale marketing contracts.

The application of derivative accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, is complex and requires our judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the normal purchases and sales exception, identifying, electing and designating hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on our consolidated financial statements.

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the company determines whether it is a derivative by using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts. The fair value of derivative assets and liabilities with the same counterparty are offset as permitted under FIN 39, "Offsetting of Amounts Related to Certain Contracts - an Interpretation of APB Opinion No. 10 and FASB Statement No. 105." The actual experience on our derivative contracts as they are settled has not resulted in a material impact on earnings. For the year ended December 31, 2008, the realized gains on the wholesale derivative contracts of Select Energy at settlement date were $3 million ($5 million pre-tax).

The judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusion 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. We currently have elected normal on many regulated company derivative contracts. If facts and circumstances change and we can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied prospectively.

In 2007, CL&P entered into CfDs with owners of plants to be built or modified. The CfDs are derivatives that are required to be marked to market on the balance sheet. However, due to the significance of the non-observable capacity prices associated with modeling the fair values of these contracts, their initial fair values were not recorded in CL&P s financial statements pursuant to EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." This guidance applies to initial fair values only, and not to subsequent changes in value. Subsequent changes in the values of these contracts were substantial, primarily due to reductions in the expected market prices of capacity. The value of CfDs at December 31, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation that were recorded upon adoption of SFAS No. 157 on January 1, 2008. The changes in CfD values since inception were recorded as a regulatory asset as the costs of the contracts are recoverable from CL&P s customers. Significant judgment was involved in estimating the fair values of the contracts, including projections of capacity prices and reflecting the probabilities of cash flows considering the risks and uncertainties associated with the contracts.

Our regulated companies, particularly CL&P and PSNH, have entered into agreements that are derivatives and do not meet the normal purchases and sales exception. These contracts are marked to market and included in derivative assets and liabilities on the accompanying consolidated balance sheets. The offset to these derivatives are generally recorded as regulatory assets or liabilities as these amounts are recoverable from or refunded to our customers as they are incurred. The measurement of many of these contracts is extremely complex, as contracts are long-dated and many of the variables, such as discount rates, future energy and energy-related product prices, and the risk associated with projects that have not been completed, require significant management judgment.

For further information, see Note 1E, "Summary of Significant Accounting Policies - Derivative Accounting," and Note 3, "Derivative Instruments," to the consolidated financial statements.

Revenue Recognition: The determination of energy sales to individual customers is based on the reading of meters, which occurs on a systematic basis throughout the month. Billed revenues are based on these meter readings and the bulk of recorded revenues is based on actual billings. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and an estimated amount of unbilled revenues is also recorded.

Unbilled revenues represent an estimate of electricity or gas delivered to customers for which the customers have not yet been billed. Unbilled revenues are included in revenue on the statement of income and are assets on the balance sheet that are reclassified to 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. There were no changes in estimating methodology in 2008.

The regulated companies estimate unbilled revenues monthly using the daily load cycle (DLC) method. The DLC method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total calendar month sales to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective rate classes, then applying an average rate to the estimate of unbilled sales.

The estimate of unbilled revenues is sensitive to numerous factors, such as energy demands, weather and changes in the composition of customer classes that can significantly impact the amount of revenues recorded. Estimating the impact of these factors is complex and requires our judgment. The estimate of unbilled revenues is important to our consolidated financial statements, as adjustments to that estimate could significantly impact operating revenues and earnings.

For further information, see Note 1D, "Summary of Significant Accounting Policies - Revenues," to the consolidated financial statements and "Transmission Rate Matters and FERC Regulatory Issues" to this Management s Discussion and Analysis.

Regulatory Accounting: The accounting policies of the regulated companies conform to GAAP applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

The application of SFAS No. 71 results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the applicable regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusion on certain factors, including but not limited to changes in the regulatory environment, recent rate orders issued by the applicable regulatory agencies and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred or probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our consolidated financial statements. We believe it is probable that the regulated companies will recover the regulatory assets that have been recorded. If we determined that we could no longer apply SFAS No. 71 to our operations, or if we could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that we record the charge in earnings at that time.

For further information, see Note 1G, "Summary of Significant Accounting Policies - Regulatory Accounting," to the consolidated financial statements.

Presentation: In accordance with GAAP, our consolidated financial statements include all subsidiaries over which control is maintained and would include any variable interest entities (VIEs) for which we are the primary beneficiary as defined in FIN 46(R), "Consolidation of Variable Interest Entities." Determining whether we are the primary beneficiary of a VIE is complex and subjective, and requires our judgment. There are a variety of facts and circumstances and a number of variables taken into consideration to determine whether we are considered the primary beneficiary of a VIE. We need to determine whether the entity is a VIE and whether our interest in the entity is a variable interest. For each VIE in which we have determined we hold a variable interest, we perform a qualitative analysis that considers the nature of the VIE s risks and determine the variability created by these risks that the VIE is designed to create and pass along to its interest holders. We evaluate the degree to which the VIE is designed to pass along risks to NU or its subsidiaries. In addition, when considered necessary to identify the primary beneficiary of the VIE, we perform modeling of the potential results of the VIE under various scenarios to quantify the degree to which it passes variability to parties that hold variable interests, including NU or one of its subsidiaries. If the majority of the variability were determined to be passed along to us, then we would be required to consolidate that VIE. A change in facts and circumstances or a change in accounting guidance could require us to reconsider whether or not we are the primary beneficiary of the VIE.

The Energy Independence Act required the DPUC to consider the impact on distribution companies of entering into long-term contracts for capacity and contracts to purchase renewable energy products from new generating plants. We reviewed each contract to determine the appropriate accounting treatment based on the terms of the contracts, which included variable and fixed pricing elements. In 2007, CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. We determined that this contract was a variable interest in a VIE. In 2008, CL&P and UI entered into seven additional long-term agreements with proposed renewable energy plants, of which four were determined to

be variable interests in VIEs and the other three were concluded not to be variable interests because of their fixed pricing elements. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these contracts with 80 percent to CL&P and 20 percent to UI (cost sharing agreement). We utilized qualitative and quantitative analyses to evaluate whether entering into the renewable energy contracts and cost sharing agreement would require CL&P to consolidate the projects and determined that consolidation would not be required. The review of these contracts required significant management judgment and incorporated quantitative modeling of the projections of each plant under a variety of possible scenarios in order to determine the allocation of risk between variable interest holders including the developers, equity investors, financing institutions and CL&P. The primary variable factors considered in these analyses were the plants operating performance and the projected market prices of energy, capacity and renewable energy credits.

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

The Energy Efficiency Act required electric distribution companies, including CL&P, and allowed others to file proposals with the DPUC to build cost-of-service peaking generation facilities. In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the DPUC (Peaker CfDs). As directed by the DPUC, CL&P and UI have entered into a cost sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these Peaker CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. Amounts paid or received under the Peaker CfDs will be recoverable from or refunded to customers. We used both qualitative and quantitative analyses to evaluate whether these contracts are variable interests in VIEs that require CL&P to consolidate the projects. CL&P determined that, while the contracts represent variable interests in VIEs, CL&P is not required to consolidate any of these projects as of December 31, 2008. For two of the projects, UI has an obligation to absorb 20 percent of the net costs or benefits of the projects through the cost sharing agreement and also holds ownership in the projects jointly with the developer. We concluded that UI is the party that is most closely associated with the VIEs due to its related party relationships with the projects and the cost sharing agreement. We performed quantitative modeling for these two projects and our qualitative analysis of UI s interests in the projects, which led us to conclude that CL&P is not required to consolidate these projects. The third peaker project is not currently held in a VIE. We utilized a quantitative model to determine the variability that CL&P would absorb if the project is transferred into a VIE and the Peaker CfD thus becomes a variable interest in a VIE. The primary variable factors considered in our quantitative analyses of the peaker projects were their projected capital costs, operating costs and operating performance as well as projected market revenues in the capacity markets. Based upon our quantitative analysis, we determined that the third project will likely require consolidation if in a future period it is transferred into a VIE. Consolidation of that project would not impact CL&P's net income, but could add approximately $140 million of plant, $85 million of nonrecourse debt and $55 million of equity (noncontrolling interest) to CL&P s balance sheet by the time the plant is placed in service (scheduled for June 2012). Any demonstrated increases in financing or other costs that might result from consolidation of the project would be recoverable from CL&P's customers.

The FASB is in the process of reinterpreting the consolidation requirements of FIN 46(R) and expects to issue revised guidance in the second quarter of 2009. If the proposed guidance were finalized in its current form, it would likely eliminate the requirement for consolidation when we do not have the power to direct matters that significantly impact the VIE's activities. CL&P would not likely be required to consolidate the peaker project if and when the new guidance becomes effective. The FASB reinterpretation of FIN 46(R), as drafted, would become effective on January 1, 2010. Changes in facts and circumstances and changes in accounting guidance resulting in reevaluation of the accounting treatment of these contracts could have a significant impact on the accompanying consolidated financial statements.

In December 2008, the FASB issued FASB Staff Position (FSP) FIN 46(R)-8, "Disclosures by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities," requiring additional disclosures about significant variable interests in variable interest entities (VIEs) effective for December 31, 2008 financial reporting. We do not have any significant variable interests in VIEs that would be required to be disclosed because our contracts do not materially impact our financial statements due to the pass-through to our customers of contract costs and benefits and because we are not currently the primary beneficiary of any VIE.

Other Matters

Consolidated Edison, Inc. Merger Litigation: On March 13, 2008, we entered into a settlement agreement with Con Edison, which settled all claims in the civil lawsuit between both parties relating to the proposed but unconsummated merger. Under the terms of the settlement agreement, we paid Con Edison $49.5 million on March 26, 2008, which resulted in an after-tax charge of $29.8 million. This amount is not recoverable from ratepayers.

Accounting Standards Issued But Not Yet Adopted:

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is effective January 1, 2009. SFAS No. 160 requires ownership interests in subsidiaries held by third parties (noncontrolling interests) to be

presented within equity and clearly identified and labeled. It sets forth requirements for income statement presentation related to the activities of noncontrolling interests and for accounting for changes in ownership interests and provides guidance for deconsolidation. Implementation of SFAS No. 160 is not expected to have a material impact on our consolidated financial statements or the consolidated financial statements of CL&P, PSNH or WMECO.

In June 2008, the FASB issued FASB Staff Position (FSP) EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities," which is effective January 1, 2009 and is required to be applied retrospectively. As a result of this FSP, our restricted stock awards that were not vested in 2007 and the first quarter of 2008 are considered participating securities in calculating EPS for these periods using the two-class method. Our restricted stock awards were completely vested during the first quarter of 2008 and are no longer awarded. FSP EITF 03-6-1 is not expected to impact our EPS for any period.

SFAS No. 157, which establishes a framework for identifying and measuring fair value, was issued in 2006 and applied in 2008 to the fair value measurements of financial assets and liabilities of NU and its subsidiaries. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 is required to be applied to nonrecurring fair value measurements of non-financial assets and liabilities beginning in 2009, including asset retirement obligations (ARO) and goodwill and other impairment analyses. Implementation of SFAS No. 157 to non-financial assets and liabilities is not expected to have a material impact on our consolidated financial statements or the consolidated financial statements of CL&P, PSNH or WMECO.

Contractual Obligations and Commercial Commitments:

Information regarding our contractual obligations and commercial commitments at December 31, 2008 is summarized annually through 2013 and thereafter as follows:

NU

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
Long-term debt maturities [a] [b]	$ 54.3	$ 4.3	$ 4.3	$ 267.3	$ 305.0	$ 3,207.8	$ 3,843.0
Estimated interest payments on existing debt [c]	222.7	219.2	218.9	210.1	194.4	2,114.8	3,180.1
Capital leases [d]	2.4	2.4	2.5	2.6	2.4	15.5	27.8

Operating leases (e)	24.6	18.9	7.1	6.1	5.9	23.9	86.5
Required funding of pension obligations (e) (f)	-	150.0	-	-	-	-	150.0
Required funding of other postretirement benefit obligations (e)	37.3	38.7	40.9	42.8	29.3	N/A	189.0
Estimated future annual regulated company costs (g)	791.6	723.9	779.7	715.0	523.6	2,855.2	6,389.0
Estimated future annual NU Enterprises costs (g)	40.3	41.9	42.9	38.8	44.7	-	208.6
Other purchase commitments (e) (h)	3,162.3	-	-	-	-	-	3,162.3
Totals (i) (j)	$ 4,335.5	$ 1,199.3	$ 1,096.3	$ 1,282.7	$ 1,105.3	$ 8,217.2	$ 17,236.3

CL&P

(Millions of Dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Totals**
Long-term debt maturities (a) (b)	$ -	$ -	$ -	$ -	$ -	$ 2,031.7	$ 2,031.7
Estimated interest payments on existing debt (c)	119.2	119.2	119.2	119.2	119.2	1,548.8	2,144.8
Capital leases (d)	1.9	1.9	1.9	2.0	1.9	14.9	24.5
Operating leases (e)	14.4	12.5	3.9	3.4	3.3	19.7	57.2
Required funding of other postretirement benefit obligations (e)	15.5	15.9	16.6	17.4	10.6	N/A	76.0
Estimated future annual costs (g)	367.9	400.9	512.6	533.7	442.0	2,478.5	4,735.6
Other purchase commitments (e) (h)	573.4	-	-	-	-	-	573.4
Totals (i) (j)	$ 1,092.3	$ 550.4	$ 654.2	$ 675.7	$ 577.0	$ 6,093.6	$ 9,643.2

(a)

Included in our debt agreements are usual and customary positive, negative and financial covenants. Non-compliance with certain covenants, for example timely payment of principal and interest, may constitute an event of default, which could cause an acceleration of principal payments in the absence of receipt by us of a waiver or amendment. Such acceleration would change the obligations outlined in the table of contractual obligations and commercial commitments.

(b)

Long-term debt maturities exclude $298.6 million and $243 million for NU and CL&P, respectively, of fees and interest due for spent nuclear fuel disposal costs, a positive $20.8 million for NU of net changes in fair value and a negative $4.9 million and $4.3 million for NU and CL&P, respectively, of net unamortized premium and discount as of December 31, 2008.

(c)

Estimated interest payments on fixed-rate debt are calculated by multiplying the coupon rate on the debt by its scheduled notional amount outstanding for the period of measurement. Estimated interest payments on floating-rate debt are calculated by multiplying the average of the 2008 floating-rate resets on the debt by its scheduled notional amount outstanding for the period of measurement. This same rate is then assumed for the remaining life of the debt. Interest payments on debt that have an interest rate swap in place are estimated using the effective cost of debt resulting from the swap rather than the underlying interest cost on the debt, subject to the fixed and floating methodologies.

(d)

The capital lease obligations include imputed interest of $14.4 million and $13.3 million for NU and CL&P, respectively, as of December 31, 2008.

(e)

Amounts are not included on our consolidated balance sheets.

(f)

The fair value of Pension Plan assets declined significantly during 2008. This decline resulted in a required contribution for the 2008 Pension Plan year. This contribution would be made just prior to the 2009 federal income tax return filing, which will likely be filed in the third quarter of 2010. We cannot determine at this time the amount of contributions that would be required for the 2009 Pension Plan year or future years.

(g)

Other than the net mark-to-market changes on respective derivative contracts held by both the regulated companies and NU Enterprises, these obligations are not included on our consolidated balance sheets. For further information on these estimated future annual costs, see Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements.

(h)

Excludes FIN 48 unrecognized tax benefits of $156.3 million for NU and $106.4 million for CL&P as of December 31, 2008, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

(i)

Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases, estimated future annual regulated company costs and the estimated future annual NU Enterprises costs. These payments are subject to change as certain purchase orders include estimates based on projected quantities of material and/or services that are provided on demand, the timing of which cannot be determined. Because payment timing cannot be determined, we include all open purchase order amounts in 2009.

(j)

For NU, excludes other long-term liabilities, including a significant portion of the FIN 48 unrecognized tax benefits described above, environmental reserves ($26.8 million), various injuries and damages reserves ($35.4 million), employee medical insurance reserves ($6.6 million), long-term disability insurance reserves ($12 million) and the ARO liability reserves ($50.6 million) as we cannot make reasonable estimates of the periods. For CL&P, excludes FIN 48 unrecognized tax benefits, described above, environmental reserves ($2.8 million), various injuries and damages reserves ($24.2 million), employee medical insurance reserves ($2 million), long-term disability insurance reserves ($3.6 million) and the ARO liability reserves ($28.7 million).

RRB amounts are non-recourse to us, have no required payments over the next five years and are not included in this table. The regulated companies' standard offer service contracts and default service contracts also are not included in this table. The estimated payments under interest rate swap agreements are not included in this table as the estimated payment amounts are not determinable. For further information regarding our contractual obligations and commercial commitments, see the consolidated statements of capitalization and Note 2, "Short-Term Debt," Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 10, "Leases," and Note 11, "Long-Term Debt," to the consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, future financial performance or growth or other statements that are not historical facts. These statements are "forward looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and other similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions or inactions by local, state and federal regulatory bodies; changes in business and economic conditions, including their impact on interest rates, bad debt expense and demand for our products and services; changes in weather patterns; changes in laws, regulations or regulatory policy; changes in levels and timing of capital expenditures; disruptions in the capital markets or events that make our access to necessary capital more difficult or costly; developments in legal or public policy doctrines; technological developments; changes in accounting standards and financial reporting regulations; fluctuations in the value of our remaining competitive electricity positions; actions of rating agencies; and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the Securities and Exchange Commission. We undertake no obligation to update the information contained in any forward looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events.

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

RESULTS OF OPERATIONS - NU CONSOLIDATED

The components of significant income statement variances for the past two years are provided in the table below (millions of dollars).

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
	Amount	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (22)	- %	$ (1,055)	(15) %
Operating Expenses:				
Fuel, purchased and net interchange power	(354)	(11)	(1,280)	(28)
Other operation	60	6	(160)	(14)
Maintenance	43	20	18	9
Depreciation	13	5	25	10
Amortization of regulatory assets, net	146	(a)	24	(a)
Amortization of rate reduction bonds	4	2	13	7
Taxes other than income taxes	15	6	1	1
Total operating expenses	(73)	(1)	(1,359)	(20)
Operating income	51	10	304	(a)
Interest expense, net	29	12	2	1
Other income, net	(11)	(18)	(3)	(4)
Income from continuing operations before income tax expense	11	3	299	(a)
Income tax expense/(benefit)	(4)	(3)	186	(a)
Preferred dividends of subsidiary	-	-	-	-
Income from continuing operations	15	6	113	85
Income/(loss) from discontinued operations	(1)	(100)	(337)	(100)
Net income/(loss)	$ 14	6 %	$ (224)	(48) %

(a) Percent greater than 100.

Net income was $14 million higher in 2008 as compared to 2007, primarily due to the growth in the company's transmission segment, partially offset by a $29.8 million after-tax charge associated with the settlement of litigation with Con Edison. Net income was $224 million lower in 2007 as compared to 2006 primarily due to the 2006 $314 million after-tax gain on the sale our competitive generation business.

Comparison of 2008 to 2007

Operating Revenues

	For the Twelve Months Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**Variance**
Electric distribution	$ 4,714	$ 4,927	$ (213)
Gas distribution	577	514	63
Total distribution	5,291	5,441	(150)
Transmission	396	283	113
Regulated companies	5,687	5,724	(37)
Competitive businesses	113	98	15
NU consolidated	$ 5,800	$ 5,822	$ (22)

Operating revenues decreased $22 million in 2008 primarily due to lower revenues from the regulated companies ($37 million), partially offset by higher revenues from competitive businesses ($15 million). The lower regulated companies revenues were primarily due to the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms. Competitive businesses revenues increased $15 million despite our continued exit from components of the competitive businesses due to higher Boulos revenues resulting from increased contractor billings ($10 million) and higher market prices for the remaining Select Energy wholesale contracts. Certain Select Energy contracts expired during 2008.

Revenues from the regulated companies decreased $37 million due to lower distribution segment revenues ($150 million), partially offset by higher transmission segment revenues ($113 million). Distribution segment revenues decreased $150 million primarily due to lower electric distribution revenues ($213 million), partially offset by higher gas distribution revenues ($63 million). Transmission segment revenues increased $113 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues decreased $213 million primarily due to the portion of revenues that does not impact earnings ($281 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, partially offset by the component of revenues that flows through to earnings ($68 million). The portion of the electric distribution segment revenues that flows through to earnings increased $68 million primarily due to increases in retail rates at each of the regulated companies ($89 million), partially offset by lower retail

electric sales ($16 million). Retail electric sales decreased 3.5 percent in 2008 compared with 2007. Gas distribution revenues increased $63 million primarily due to increased recovery of higher gas costs, the rate increase effective July 1, 2007 and higher firm gas sales. Firm gas sales increased 2.1 percent in 2008 compared with 2007.

The $281 million electric distribution revenue decrease that does not impact earnings is due to the components of CL&P, PSNH and WMECO retail revenues that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($179 million) and revenues that are eliminated in consolidation ($102 million). The distribution revenue tracking components decreased $179 million primarily due to revenues associated with the recovery of generation service and related congestion charges ($233 million) and CL&P delivery-related FMCC ($75 million) and lower PSNH SCRC ($55 million), partially offset by higher CL&P wholesale revenues primarily due to an increase in the market price of energy related to sales of IPP generation to ISO-NE ($59 million) and higher CL&P and PSNH retail transmission revenues ($82 million) mainly as a result of the higher 2008 rates and higher CL&P SBC revenue ($36 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $354 million in 2008 due to lower costs at the regulated companies ($364 million), partially offset by higher competitive businesses expenses ($9 million). Fuel expense from the regulated companies decreased primarily at CL&P due to lower GSC supply costs, a decrease in deferred fuel costs and lower other purchased power costs. The decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales ($432 million), partially offset by higher Yankee Gas expenses ($41 million) primarily due to higher fuel prices in 2008 and higher PSNH fuel expense ($28 million) primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired. Competitive businesses' expenses increased due to higher Select Energy purchased power expenses related to the remaining wholesale contracts.

Other Operation

Other operation increased $60 million in 2008 primarily due to higher NU parent and other companies   expenses ($54 million), higher competitive businesses' expenses ($6 million) and higher regulated companies   distribution and transmission segment expenses ($1 million).

NU parent and other companies' expenses are higher by $54 million in 2008 primarily due to the $49.5 million payment to Con Edison resulting from the settlement of litigation. Competitive businesses' expenses are higher by $6 million primarily due to higher operating costs at the remaining services businesses.

Higher regulated companies' distribution and transmission segment expenses of $1 million are primarily due to higher transmission segment expenses ($8 million), expenses at Yankee Energy System, Inc. ($6 million) and higher electric distribution segment expenses ($4 million), partially offset by consolidation eliminations of transmission segment intracompany billings to the distribution segment, and further eliminations for NU consolidations and costs that are tracked and recovered through distribution tracking mechanisms ($18 million).

Maintenance

Maintenance expenses increased $43 million in 2008 primarily due to higher regulated companies' distribution expenses ($38 million) and higher transmission line expenses ($4 million). Distribution expenses are $38 million higher primarily due to higher PSNH generation expenses that are tracked and recovered through NHPUC approved tracking mechanisms ($15 million) mainly related to the Merrimack Station maintenance outages, higher tree trimming ($9 million), higher overhead line maintenance expenses ($5 million), substation equipment ($3 million) and line transformers ($2 million).

Depreciation

Depreciation increased $13 million in 2008 primarily due to higher regulated transmission and distribution plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased $146 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($144 million) resulting from a higher recovery of transition costs ($62 million), higher amortization of SBC ($50 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($29 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $4 million in 2008. The higher portion of principal within the RRB payments results in a corresponding increase in the amortization of RRBs. This increase was partially offset by a decrease at PSNH resulting from the retirement of $50 million of RRBs in the first quarter of 2008.

Taxes Other than Income Taxes

Taxes other than income taxes increased $15 million in 2008 primarily due to higher Connecticut gross earnings tax ($16 million) mainly as a result of higher CL&P and Yankee Gas revenues that are subject to gross earnings tax and higher property taxes at CL&P and PSNH ($5 million) as a result of higher plant balances and higher local municipal tax rates, partially offset by lower payroll taxes charged to expense ($5 million).

62

Interest Expense, Net

Interest expense, net increased $29 million in 2008 primarily due to higher long-term debt interest ($31 million) resulting from the issuance of new long-term debt in 2007 and 2008 and higher other interest ($9 million) mostly related to short-term debt, partially offset by lower RRB interest resulting from lower principal balances outstanding ($11 million).

Other Income, Net

Other income, net decreased $11 million in 2008 primarily due to lower investment income ($16 million) primarily due to the absence of the higher NU investment income interest earned in 2007 on cash the parent received from the November 2006 sale of NU's competitive generation, higher investment losses ($14 million) primarily due to the supplemental benefit trust and lower equity in earnings of regional nuclear generating and transmission companies ($2 million), partially offset by higher AFUDC equity income ($12 million) and interest income related to the 2008 tax settlement ($10 million).

Income Tax Expense

Income tax expense decreased $4 million in 2008 primarily due to the Con Edison settlement ($20 million), temporary flow through plant differences ($6 million), partially offset by impacts associated with higher pre-tax earnings ($22 million).

Comparison of 2007 to 2006

Operating Revenues

	For the Twelve Months Ended December 31,					
(Millions of Dollars)		**2007**		**2006**		**Variance**
Electric distribution	$	4,927	$	5,332	$	(405)
Gas distribution		514		453		61
Total distribution		5,441		5,785		(344)
Transmission		283		200		83
Regulated companies		5,724		5,985		(261)
Competitive businesses		98		892		(794)

NU consolidated	$	5,822	$	6,877	$	(1,055)

Net income is $224 million lower in 2007 due to the two significant gains in 2006 that did not occur in 2007. These gains were an after-tax gain of $314 million associated with the sale of the competitive generation business and the CL&P $74 million income tax reduction associated with the PLR. The negative impact on net income of the 2006 gains was partially offset by the $107 million higher earnings of NU Enterprises due to the $96 million loss in 2006.

Operating Revenues

Operating revenues decreased $1.06 billion in 2007 primarily due to lower revenues from NU Enterprises ($794 million) and lower revenues from the regulated companies ($261 million). NU Enterprises' revenues decreased $794 million due to the exit from components of the competitive businesses during the latter part of 2006. The lower regulated revenues are being driven by the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms.

Revenues from the regulated companies decreased $261 million due to lower distribution segment revenues ($344 million), partially offset by higher transmission segment revenues ($83 million). Distribution segment revenues decreased $344 million primarily due to lower electric distribution revenues ($405 million), partially offset by higher gas distribution revenues ($61 million). Transmission segment revenues increased $83 million primarily due to a higher transmission investment base and higher operating expenses that are recovered under FERC-approved transmission tariffs.

Lower electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($447 million). The distribution revenue tracking components decrease of $447 million is primarily due to the pass through of lower energy supply costs ($305 million), lower CL&P revenue associated with the recovery of delivery-related FMCC ($104 million), a decrease in PSNH s SCRC revenues mainly as a result of a rate decrease that went into effect July 1, 2006 ($76 million) and lower wholesale revenues ($28 million), partially offset by higher retail transmission revenues ($43 million), WMECO s higher transition cost recoveries ($15 million) and WMECO s pension and default service revenues ($8 million). The tracking mechanisms allow for rates to be changed periodically with over-collections refunded to customers or under-collections collected from customers in future periods.

The distribution component of electric distribution segment revenues that flows through to earnings increased $42 million primarily due to an increase in retail rates ($31 million) and retail sales ($11 million). Retail KWH electric sales increased by 1.5 percent in 2007 compared with 2006 (a 0.4 percent increase on a weather normalized basis). Firm gas sales increased 10.3 percent in 2007 compared with 2006 (a 3.1 percent increase on a weather normalized basis).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $1.28 billion in 2007 due to lower expenses at NU Enterprises ($875 million) and lower costs at the regulated companies ($405 million). NU Enterprises' fuel expenses decreased due to the exit from significant components of the competitive businesses. Fuel expense from the regulated companies decreased primarily due to lower fuel, purchased and net interchange power expenses at CL&P, PSNH and WMECO ($431 million), mainly due to a decrease in standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers, partially offset by higher Yankee Gas fuel expense ($26 million).

Other Operation

Other operation expenses decreased $160 million in 2007 primarily due to lower NU Enterprises expenses ($115 million) and lower regulated companies distribution and transmission segment expenses ($49 million).

NU Enterprises' expenses decreased $115 million primarily due to the exit from components of the competitive businesses during the latter part of 2006 and the $25 million donation to the NU Foundation in 2006.

Lower regulated company distribution and transmission segment expenses of $49 million are primarily due to lower reliability must run (RMR) expenses at CL&P ($133 million), partially offset by higher Energy Independence Act (EIA) expenses that are tracked and recovered through the regulatory tracking mechanisms ($29 million), higher administration and general expenses at CL&P, WMECO and PSNH ($22 million), higher retail transmission expenses at PSNH and WMECO ($21 million) and Summer Savings Rewards Program that was implemented in 2007 at CL&P as a result of a legislative act ($14 million).

Maintenance

Maintenance expenses increased $18 million in 2007 primarily due to higher transmission segment expenses ($7 million) and regulated company distribution ($6 million).

Higher transmission segment expenses of $7 million in 2007 are primarily due to higher levels of employee support, compliance inspections, deferred maintenance, training, and unplanned repairs to transmission cables at CL&P.

Higher regulated company distribution expenses of $6 million in 2007 are primarily due to higher tree trimming ($3 million), equipment maintenance ($2 million) and underground line network inspection activities ($2 million).

Depreciation

Depreciation increased $25 million in 2007 primarily due to higher distribution and transmission depreciation expense as a result of higher plant balances from the ongoing construction program.

Amortization

Amortization increased $24 million in 2007 for the distribution segment primarily due to higher recovery of transition costs for CL&P ($32 million) and WMECO ($20 million) and the 2006 $18 million credit associated with the deferral of retail transmission costs for WMECO, partially offset by PSNH ($46 million). The PSNH decrease is primarily due to lower ES over recoveries, lower amortization levels of stranded costs, and the deferral of retail transmission costs.

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $13 million in 2007. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

Interest Expense, Net

Interest expense increased $2 million in 2007 primarily due to higher interest for the regulated company distribution and transmission segments ($22 million), partially offset by lower interest at NU Enterprises ($19 million). The higher regulated company distribution and transmission segment interest is primarily due to long-term debt issuances for all four of the regulated companies. In 2007, $655 million of long-term debt was issued by the regulated companies consisting of $500 million for CL&P, $70 million for PSNH, $40 million for WMECO and $45 million for Yankee Gas.

Other Income, Net

Other income, net decreased $3 million, primarily due to a lower CL&P Traditional Standard Offer procurement fee ($11 million) and the absence of the gain on sale of investment in Globix Corporation (Globix) in 2006 ($3 million), partially offset by higher EIA incentives ($4 million), higher equity in earnings of regional nuclear generating and transmission companies ($4 million), and higher AFUDC equity ($4 million) mainly as a result of higher eligible construction work in progress.

Income Tax (Benefit)/Expense

Income tax expense increased $186 million primarily due to an increase in pre-tax earnings and lower favorable tax adjustments; partially offset by a decrease in flow through regulatory amortizations. In 2006, a significant portion of the tax adjustments included a $74 million tax benefit to remove deferred tax balances associated with the IRS PLR. Prior year flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

Income/(Loss) from Discontinued Operations

See Note 15, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements for a description and explanation of the discontinued operations.

RESULTS OF OPERATIONS - THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ (123)	(3) %	$ (298)	(7) %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	(432)	(19)	(327)	(13)
Other operation	22	4	(79)	(13)
Maintenance	22	21	7	6
Depreciation	11	7	4	3
Amortization of regulatory assets/(liabilities), net	144	(a)	32	(a)
Amortization of rate reduction bonds	10	7	9	7
Taxes other than income taxes	11	7	7	4
Total operating expenses	(212)	(6)	(347)	(9)
Operating Income	89	31	49	21
Interest expense, net	8	6	21	17
Other income, net	2	5	2	5
Income before income tax expense	83	45	30	19
Income tax expense	25	49	96	(a)
Net income	$ 58	43 %	$ (66)	(33) %

(a) Percent greater than 100.

<u>Comparison of the Year 2008 to the Year 2007</u>

Operating Revenues

Operating revenues decreased $123 million due to lower distribution segment revenues ($233 million), partially offset by higher transmission segment revenues ($110 million).

The distribution segment revenues decreased $233 million primarily due to the component of revenues that does not impact earnings ($296 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations, partially offset by the component of revenues that flows through to earnings, which increased $62 million.

The $296 million distribution segment revenue decrease that does not impact earnings is primarily due to the components of retail revenues that are included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs ($217 million) and consolidation eliminations of transmission segment intracompany billings to the distribution segment ($78 million). The distribution revenue included in DPUC approved tracking mechanisms that track the recovery of certain incurred costs decreased $217 million primarily due to a decrease in revenues associated with the recovery of GSC and related FMCC ($314 million) and delivery related FMCC ($75 million), partially offset by higher retail transmission revenues ($65 million) mainly as a result of higher 2008 rates, higher wholesale revenues ($59 million), and higher SBC revenues ($36 million). The lower GSC and related FMCC revenue was primarily due to a reduction in load, caused primarily by customer migration to third party suppliers, lower congestion costs and lower sales in 2008. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2008 as a result of lower RMR, VAR support and southwest Connecticut energy resource costs in 2008, as well as a larger prior year overrecovery being refunded to customers in 2008 as compared to 2007. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

The portion of the distribution segment revenues that flows through to earnings increased $62 million primarily due to the rate increase effective February 1, 2008 ($75 million), partially offset by lower retail sales ($10 million). Retail sales decreased 3.7 percent in 2008 compared to 2007.

Transmission segment revenues increased $110 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $432 million primarily due to a decrease in GSC supply costs ($231 million), a decrease in deferred fuel costs ($174 million) and lower other purchased power costs ($27 million), all of which are included in DPUC approved tracking mechanisms. The $231 million decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales. These GSC supply costs are the contractual amounts CL&P must pay to various suppliers that have earned the right to supply SS and LRS load through a competitive solicitation process. The $174 million decrease in deferred fuel costs was primarily due to the combined effect of CL&P having a supply and delivery-related net FMCC overrecovery in 2007 and a supply and delivery-related net FMCC underrecovery in 2008.

65

Other Operation

Other operation expenses increased $22 million primarily due to higher costs that are tracked and recovered through distribution tracking mechanisms ($104 million) such as retail transmission ($59 million), RMR ($17 million), higher uncollectibles ($12 million), higher tracked administrative and general expenses ($9 million), and higher EIA expenses ($6 million). In addition, there were higher transmission segment expenses ($5 million), partially offset by consolidation eliminations of transmission segment intracompany billing to the distribution segment ($80 million) and lower distribution segment expenses ($8 million) primarily due to lower pension, regulatory assessments and workers compensation expenses, partially offset by a charge to refund the 2004 procurement incentive fee that was recognized in 2005 earnings.

Maintenance

Maintenance expenses increased $22 million in 2008 primarily due to higher distribution overhead lines ($10 million), primarily due to more storms in 2008 compared to 2007, higher tree trimming expenses ($6 million), higher transmission segment expenses ($4 million) and higher distribution substation equipment ($2 million).

Depreciation

Depreciation expense increased $11 million primarily due to higher utility plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $144 million primarily due to higher amortization related to the recovery of transition charges ($62 million), a higher recovery and lower expenses for SBC ($50 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($29 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $10 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $11 million primarily due to higher gross earnings taxes as a result of higher distribution revenues that are subject to gross earnings tax ($13 million) and higher property taxes as a result of higher plant balances and higher municipal tax rates ($2 million), partially offset by lower payroll taxes charged to expense ($3 million).

Interest Expense, Net

Interest expense, net increased $8 million primarily due to higher long-term debt interest ($21 million) resulting from the $200 million debt issuance in September 2007, the $300 million debt issuance in March 2007 and the $300 million debt issuance in May 2008, partially offset by lower RRB interest resulting from lower principal balances outstanding ($9 million) and lower other interest ($3 million) mostly related to short-term debt.

Other Income, Net

Other income, net increased $2 million primarily due to a higher AFUDC equity income ($9 million) as a result of higher eligible CWIP due to the transmission construction program, higher interest income related to the 2008 federal tax settlement ($6 million) and higher EIA incentives ($2 million), partially offset by higher investment losses ($10 million) primarily due to the supplemental benefit trust, a decrease in conservation and load management incentive income ($3 million) and a decrease in investment income ($2 million).

Income Tax Expense

Income tax expense increased $25 million primarily due to higher pre-tax earnings being subject to tax at marginal rates, partially offset by flow through impacts associated with plant differences and bad debts, thereby reducing the effective tax rate.

<u>Comparison of the Year 2007 to the Year 2006</u>

Operating Revenues

Operating revenues decreased $298 million due to lower distribution segment revenues ($373 million), partially offset by higher transmission segment revenues ($75 million).

The distribution segment revenue decrease of $373 million is primarily due to the components of revenues, which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($388 million). The distribution segment revenue tracking components decreased $388 million primarily due to a decrease in revenues associated with the recovery of generation service and related congestion charges ($265 million) and lower delivery-related FMCC revenue ($104 million). The lower generation service and related congestion charge revenue was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, partially offset by an increase in these rate components to recover higher 2007 supply prices. The lower delivery-related FMCC revenue was primarily due to a decrease in this rate component in 2007 as a result of the use of prior year overrecoveries to recover current year costs, as well as lower anticipated RMR costs in 2007. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods.

The distribution component of revenues that impacts earnings increased $14 million as a result of the rate increase effective January 1, 2007 and higher retail sales. Retail sales increased 1.7 percent in 2007 compared to the same period in 2006.

Transmission segment revenues increased $75 million primarily due to a higher rate base and higher operating expenses, which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased $327 million primarily due to a decrease in generation service supply costs ($286 million) and lower other purchased power costs ($73 million), partially offset by an increase in deferred fuel costs of $32 million, all of which are included in regulatory commission-approved tracking mechanisms. The $286 million decrease in supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers, partially offset by higher 2007 supply prices. These supply costs are the contractual amounts the company must pay to various suppliers that have earned the right to supply Standard Service and Last Resort Service load through a competitive solicitation process. The $32 million increase in deferred fuel costs was largely the result of the deferral of significant refunds received from the ISO-NE associated with previously remitted RMR payments that must be returned to customers.

Other Operation

Other operation expenses decreased $79 million primarily due to lower RMR costs ($133 million) that are tracked and recovered through the FMCC, partially offset by higher Energy Independence Act (EIA) expenses that will also be recovered through the FMCC deferral mechanism ($29 million), Summer Saver Rewards Program that was implemented in 2007 as a result of a legislative act ($14 million) and higher administrative expense ($8 million).

Maintenance

Maintenance expenses increased $7 million primarily due to higher transmission segment expenses ($5 million) and higher distribution segment expenses ($2 million).

Higher transmission segment expenses of $5 million in 2007 are primarily due to higher levels of employee support, compliance inspections, deferred maintenance, training, and unplanned repairs to transmission cables at CL&P.

Higher distribution segment expenses of $2 million in 2007 are primarily due to higher expenses related to substation maintenance, underground network inspection activities, line transformer maintenance, partially offset by lower expenses related to overhead lines maintenance primarily due to less storm-related expense.

Depreciation

Depreciation expense increased $4 million primarily due to higher utility plant balances resulting from the ongoing construction program.

Amortization of Regulatory Assets/(Liabilities), Net

Amortization of regulatory assets/(liabilities), net increased $32 million primarily due to higher amortization related to the recovery of transition charges ($32 million), higher SFAS No. 109 amortization ($7 million), partially offset by a lower system benefit charge deferral ($8 million).

Amortization of Rate Reduction Bonds

Amortization of RRBs increased $9 million. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $7 million primarily due to higher property taxes primarily related to new transmission projects such as the Bethel-Norwalk project that were completed in 2006, but not reflected in our tax assessment until 2007.

Interest Expense, Net

Interest expense, net increased $21 million primarily due to higher interest on long-term debt ($19 million) mainly as a result of $250 million of new debt issued in June of 2006, $300 million of new debt issued in March of 2007 and $200 million of new debt issued in September of 2007, higher FMCC deferral interest ($6 million) and higher interest on short-term debt ($2 million), partially offset by lower RRB interest resulting from lower principal balances outstanding ($9 million).

Other Income, Net

Other income, net increased $2 million primarily due to a higher equity AFUDC income ($7 million) as a result of higher eligible CWIP due to the transmission construction program, higher EIA incentives ($4 million) and higher equity of earnings of regional nuclear generating companies ($3 million), partially offset by the elimination of the Transitional Standard Offer (TSO) procurement fee approved by the DPUC associated with the TSO supply procurement that expired at the end of 2006 ($11 million).

Income Tax Expense

Income tax expense increased $96 million primarily due to the nonrecurring tax items in 2006 that included a $74 million tax benefit from the removal of deferred tax balances associated with a PLR received from the IRS, a decrease in favorable tax adjustments, lower state tax credits and higher pre-tax earnings.

LIQUIDITY

While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that CL&P has sufficient operating flexibility and access to funding sources to maintain adequate amounts of liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for CL&P are all stable, with all its ratings and outlooks affirmed by S&P in late October 2008. CL&P has modest risk of calls for collateral due to its business model, as described under "Liquidity-Impact of Financial Market Conditions" in this "Management s Discussion and Analysis of Financial Condition and Results of Operations." Capital contributions from NU parent and other internal sources of funding are provided to CL&P as necessary. CL&P does not have any long-term debt maturing in 2009, and projected capital expenditures for 2009 are significantly less than 2008.

CL&P had consolidated operating cash flows of $267.3 million in 2008, after RRB payments included in financing activities, compared with operating cash flows of $4.5 million in 2007 and $138.8 million in 2006, both after RRB payments. Operating cash flows in 2007 include tax payments of approximately $177.2 million related to the 2006 sale of NU's competitive generation business. Other drivers resulting in increased operating cash flows in 2008 were higher operating results after adjustments for reconciling items to net income primarily related to the significant increase in transmission segment earnings and a $77.8 million annualized increase in distribution rates, effective February 1, 2008. The increase in operating cash flows was also due to an income tax net settlement of approximately $33 million in the fourth quarter of 2008 and the cash flow benefit of our accounts payable balances having increased by $25 million. These factors were partially offset by a net reduction in other working capital items resulting primarily from a net $141 million increase in the cash flow benefit of our accounts receivable and unbilled revenue balances, which also included investments in securitizable assets.

CL&P projects consolidated operating cash flows of approximately $365 million in 2009, after approximately $183 million of RRB payments. This projection represents an increase of approximately $100 million from 2008 operating cash flows, after RRB payments, which is primarily due to the reflection in 2009 rates of CL&P s major southwest Connecticut transmission projects completed in 2008; a $20.1 million annualized increase in distribution rates, effective February 1, 2009; and the recovery in 2009 of certain regulatory underrecoveries as of December 31, 2008, including $31.9 million from its semi-annual FMCC filing in February 2009 as compared to a $105 million overrecovery at December 31, 2007.

On February 13, 2009, CL&P issued $250 million of first and refunding mortgage bonds due February 1, 2019 and carrying a coupon of 5.5 percent. Proceeds from this issuance will be used to repay short-term debt and fund CL&P's capital investment program, which is projected to be approximately $400 million in 2009. In mid-2009 or earlier depending on market opportunities, NU expects to issue between $250 million and $300 million of equity, a portion of which will be used to fund CL&P s 2009 capital investment program. This program will also be funded by available short-term borrowings and the projected growth in 2009 operating cash flows described above.

As of December 31, 2008 and February 25, 2009, CL&P had borrowings of $188 million under the $400 million credit facility it shares with other NU subsidiaries, of which it can borrow up to $200 million. Other financing activities for 2008 included a $300 million issuance of 10-year bonds in May 2008 and capital contributions from NU parent of $210 million, offset by $106.5 million in common dividends paid to NU parent.

On June 30, 2008, due to the availability and lower relative cost of other liquidity sources, CL&P chose to terminate the arrangement under which CL&P could sell to a financial institution up to $100 million of accounts receivable and unbilled revenues.

Cash capital expenditures included on the accompanying consolidated statements of cash flows do not include amounts incurred on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. CL&P s cash capital expenditures totaled $849.5 million in 2008, compared with $826.2 million in 2007. This increase was primarily the result of higher distribution segment capital expenditures in 2008.

RESULTS OF OPERATIONS - PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances	**2008 over/(under) 2007**		**2007 over/(under) 2006**	
(Millions of Dollars)	**Amount**	**Percent**	**Amount**	**Percent**
Operating Revenues	$ 58	5 %	$ (58)	(5) %
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	28	5	(58)	(10)
Other operation	7	3	30	17
Maintenance	17	23	3	4
Depreciation	3	6	4	7
Amortization of regulatory assets, net	2	24	(46)	(86)
Amortization of rate reduction bonds	(7)	(13)	3	6
Taxes other than income taxes	2	7	2	5
Total operating expenses	52	5	(62)	(6)
Operating Income	6	5	4	3
Interest expense, net	4	8	-	-
Other income, net	1	9	(1)	(9)
Income before income tax expense	3	4	3	4
Income tax expense	(1)	(4)	(16)	(42)
Net income	$ 4	7 %	$ 19	54 %

<u>Comparison of the Year 2008 to the Year 2007</u>

Operating Revenues

Operating revenues increased $58 million in 2008 due to higher distribution segment revenues ($46 million) and higher transmission segment revenues ($12 million).

The distribution segment revenues increased $46 million primarily due to the portion of revenues that does not impact earnings ($37 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, and the component of revenues that flows through to earnings ($8 million). The portion of distribution segment revenues that flows through to earnings increased $8 million primarily as a result of rate changes ($13 million) from increases effective July 1, 2007 and January 1, 2008, partially offset by a rate decrease effective July 1, 2008. The combined increase in rates is partially offset by lower retail sales ($4 million). Retail sales decreased 2.5 percent in 2008 compared to the same period in 2007.

The $37 million distribution from revenue increase that does not impact earnings is due to the components of retail revenues that are included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs ($55 million), partially offset by revenues that are eliminated in consolidation ($18 million). The distribution revenue included in NHPUC approved tracking mechanisms that track the recovery of certain incurred costs increased $55 million primarily due to the pass-through of higher energy supply costs ($78 million), higher retail transmission revenues ($17 million), higher wholesale revenues ($8 million), and higher Northern Wood Power Plant renewable energy certificate revenues ($3 million), partially offset by a decrease in the SCRC ($55 million) primarily due to a decrease in the SCRC rate effective July 1, 2008. The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Transmission segment revenues increased $12 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under F