EXHIBIT 1

NORTHEAST UTILITIES

10-K

Annual report pursuant to section 13 and 15(d)
Filed on 2/24/2012
Filed Period 12/31/2011

Northeast Utilities

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, 2011
OR

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

For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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.

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 whether the registrants have submitted electronically and posted on its corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S–T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

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, 2011) was **$6,218,948,649** based on a closing sales price of **$35.17** per share for the 176,825,381 common shares outstanding on June 30, 2011. **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 issuers' classes of common stock, as of the latest practicable date:

Company - Class of Stock	Outstanding as of January 31, 2012
Northeast Utilities Common shares, $5.00 par value	177,203,768 shares
The Connecticut Light and Power Company Common stock, $10.00 par value	6,035,205 shares
Public Service Company of New Hampshire Common stock, $1.00 par value	301 shares
Western Massachusetts Electric Company Common stock, $25.00 par value	434,653 shares

GLOSSARY OF TERMS

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

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

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

REGULATORS:

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

OTHER:

2010 Healthcare Act	Patient Protection and Affordable Care Act
AOCI	Accumulated Other Comprehensive Income/(Loss)
AFUDC	Allowance For Funds Used During Construction
AMI	Advanced metering infrastructure
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CERLA	The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
CfD	Contract for Differences
CO_2	Carbon dioxide
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
CYAPC	Connecticut Yankee Atomic Power Company
DOER	Massachusetts Department of Energy Resources
EIA	Energy Independence Act
EMF	Electric and Magnetic Fields
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights

GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gas
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
KV	Kilovolt
kWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Supplier of last resort service
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up of Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001.
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solution
NO_x	Nitrogen oxide
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NPDES	National Pollutant Discharge Elimination System
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
OCI	Other Comprehensive Income
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PGA	Purchased Gas Adjustment
PPA	Pension Protection Act
RECs	Renewable Energy Certificates
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segment excluding the wholesale transmission segment
RGGI	Regional Greenhouse Gas Initiative
RNS	Regional Network Service
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company
WWL Project	The construction of a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut and the increase of vaporization output of Yankee Gas' LNG plant
YAEC	Yankee Atomic Electric Company
Yankee Companies	Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company and Maine Yankee Atomic Power Company

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

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

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

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

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

PART I

Item 1.
Business

Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this Annual Report on Form 10-K.

PENDING MERGER WITH NSTAR

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

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

Completion of the merger is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. NU and NSTAR are awaiting approvals from PURA and the DPU.

In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned PURA to reconsider its earlier conclusion that it lacked jurisdiction to review the merger. On June 1, 2011, PURA declined to change its conclusion that it lacked jurisdiction over the merger. However, on January 18, 2012, PURA issued a decision that revised its June 1, 2011 decision. The January 18, 2012 decision ruled that NU and NSTAR must seek approval from PURA pursuant to Connecticut law prior to completing the merger. NU and NSTAR filed an application with PURA seeking approval of the merger on January 19, 2012. Hearings began February 14, 2012 and PURA is scheduled to issue a final decision on April 2, 2012.

On November 24, 2010, NU and NSTAR filed a joint petition requesting the DPU's approval of the merger and filed supplemental testimony and a net benefit analysis with the DPU on April 8, 2011, in response to the DPU's revision of its merger standard to a "net benefits" standard. On February 15, 2012, NU and NSTAR reached comprehensive merger-related settlement agreements with both the Massachusetts DOER and the Massachusetts AG. The first settlement agreement was reached with both the AG and the DOER and covers a variety of rate-making and rate design issues, including a distribution rate freeze until 2016 for NSTAR Electric Company, NSTAR Gas Company and WMECO. The second settlement agreement was reached with the DOER and covers a variety of matters impacting the advancement of Massachusetts clean energy goals established by the Green Communities Act and Global Warming Solutions Act.

Pursuant to the terms and provisions of the settlement agreements, the parties agree that the proposed merger between NU and NSTAR is consistent with the public interest and should be approved by the DPU. However, the settlement agreements allow the Attorney General and DOER to terminate their respective agreements for any reason at any time prior to approval by the DPU. All parties have requested that the DPU approve the merger on April 4, 2012. If both the DPU and PURA issue acceptable decisions by that date, we expect the merger will be consummated by April 16, 2012.

All other approvals required to consummate the merger have been received. For further information regarding regulatory approvals on the pending merger, see "Regulatory Developments and Rate Matters – Regulatory Approvals for Pending Merger with NSTAR," in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations,* in this Annual Report on Form 10-K.

THE COMPANY

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by FERC under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly owned utility subsidiaries:

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

- Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire and owns generation assets used to serve customers;

- Western Massachusetts Electric Company (WMECO), a regulated electric utility that serves residential, commercial and industrial customers in parts of western Massachusetts and owns solar generating assets; and

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

NU also owns certain unregulated businesses through its wholly owned subsidiary, NU Enterprises, which are included in its Parent and other companies' results of operations.

Although NU, CL&P, PSNH and WMECO each report their financial results separately, we also include information in this report on a segment, or line-of-business, basis - the distribution segment (which also includes the generation businesses of PSNH and WMECO and our natural gas distribution business) and the transmission segment. Our distribution segment represented approximately 53 percent of our Regulated companies' earnings and our electric transmission segment represented approximately 47 percent.

REGULATED ELECTRIC DISTRIBUTION

General

NU's electric distribution segment consists of the distribution businesses of CL&P, PSNH and WMECO, which are engaged in the distribution of electricity to retail customers in Connecticut, New Hampshire and western Massachusetts, respectively, plus the regulated electric generation businesses of PSNH and WMECO. The following table shows the sources of 2011 electric franchise retail revenues for NU's electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	58
Commercial	33
Industrial	7
Other	2
Total	100%

A summary of changes in the electric distribution companies' retail electric sales (GWh) for 2011, as compared to 2010, on an actual and weather normalized basis (using a 30-year average) is as follows:

	2011	2010	Percentage Decrease	Weather Normalized Percentage Decrease
Residential	14,766	14,913	(1.0)%	(0.2)%
Commercial	14,301	14,506	(1.4)%	(0.3)%
Industrial	4,418	4,481	(1.4)%	(0.2)%
Other	327	330	(1.0)%	(1.0)%
Total	33,812	34,230	(1.2)%	(0.3)%

Actual retail electric sales for all three electric companies were lower in 2011 compared to 2010 due primarily to milder weather in the summer of 2011, compared to warmer than normal weather in the summer of 2010. In 2011, cooling degree days in Connecticut and western Massachusetts were 20.9 percent lower than 2010, and in New Hampshire, cooling degree days were 23.7 percent lower than 2010.

On a weather-normalized basis, total retail electric sales decreased slightly in 2011, as compared to 2010. We believe the weather-normalized commercial sales for CL&P and WMECO decreased in 2011, compared to 2010, due to the slow economic recovery in these service areas. PSNH commercial sales increased in 2011 due to one large self-generating customer who experienced multiple generation outages and relied on PSNH for energy. Industrial sales for both CL&P and WMECO decreased in 2011, compared to 2010, due in part to weak manufacturing activity in Connecticut and western Massachusetts. Our commercial and industrial electric sales continue to be negatively impacted by utilization of distributed generation and conservation programs.

Major Storms

On August 28, 2011, Tropical Storm Irene caused extensive damage to our distribution system resulting in incremental restoration costs of $135.6 million. Approximately 800,000 of our 1.9 million electric distribution customers were without power at the peak of the outages, with approximately 670,000 of those customers in Connecticut.

On October 29, 2011, an unprecedented autumn snowstorm inundated our service territory with heavy snow, causing significant damage to our distribution and transmission systems resulting in incremental restoration costs of $218.5 million. Approximately 1.2 million of our electric distribution customers were without power at the peak of the outages, with approximately 810,000 of those customers in Connecticut, approximately 237,000 of those customers in New Hampshire, and approximately 140,000 of those customers in Massachusetts. In terms of customer outages, this was the most severe storm in CL&P's history, surpassing Tropical

Storm Irene; the third most severe in PSNH's history, following a December 2008 ice storm and a February 2010 winter storm; and the most severe in WMECO's history.

CL&P recorded a pre-tax charge for a storm fund reserve of $30 million, in the fourth quarter of 2011, to provide bill credits to its residential customers who remained without power after noon on Saturday, November 5, 2011 as a result of the October snowstorm, and to provide contributions to certain Connecticut charitable organizations. Approximately $27 million of the storm fund reserve was used to provide a one-time credit on the February 2012 bills of approximately 192,000 CL&P customers and approximately $3 million was paid to charitable organizations in December 2011. CL&P will not seek to recover this amount in its rates.

Estimated incremental restoration costs related to the two storms are summarized in the table below and consist of costs that are deferred for future recovery and costs that are capitalized:

	For the Year Ended December 31, 2011					
(Millions of Dollars)		Deferred for Future Recovery		Capitalized		Total Incremental Costs
Tropical Storm Irene:						
CL&P	$	105.6	$	18.2	$	123.8
PSNH		7.0		1.1		8.1
WMECO		3.2		0.5		3.7
Total Tropical Storm Irene		115.8		19.8		135.6
October Snowstorm:						
CL&P		157.7		16.9		174.6
PSNH		14.7		2.2		16.9
WMECO		23.5		3.5		27.0
Total October Snowstorm		195.9		22.6		218.5
Total Storm Costs	$	311.7	$	42.4	$	354.1

We believe our response to both storms was prudent and therefore we believe it is probable that CL&P, PSNH and WMECO will be allowed to recover these storm costs. Each operating company will seek recovery of its estimated deferred storm costs through its applicable regulatory recovery process. For further information regarding various reviews on storm response and preparedness, see "Regulatory Developments and Rate Matters – 2011 Major Storms," in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Annual Report on Form 10-K.

THE CONNECTICUT LIGHT AND POWER COMPANY - DISTRIBUTION

CL&P's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2011, 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 CL&P's 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	59
Commercial	32
Industrial	6
Other	3
Total	100%

Rates

CL&P is subject to regulation by PURA, 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, CTA, SBC and other charges that are assessed on all customers.

The CTA is a charge assessed to recover stranded costs associated with electric industry restructuring as well as various IPP contracts. The SBC recovers costs associated with various hardship and low income programs as well as payments to municipalities to compensate them for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring. The CTA and SBC are annually reconciled to actual costs incurred, with any difference refunded to, or recovered from, customers.

Under Connecticut law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains their electric distribution company. Under SS rates for customers with less than 500 kilowatts of demand and LRS rates for customers with 500 kilowatts of demand or greater, CL&P purchases power for those customers who do not choose a competitive energy supplier and passes the cost to such customers through a combined GSC and FMCC charge on customers' bills. The combined GSC and FMCC charges for both types of service recover all of CL&P's costs of procuring energy from wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of PURA.

CL&P continues to supply approximately 35 percent of its customer load at SS or LRS rates while the other 65 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on CL&P's delivery business or its operating income.

Distribution Rates: On June 30, 2010, PURA issued a final order in CL&P's most recent retail distribution rate case approving annualized distribution rate increases of $63.4 million effective July 1, 2010 and an incremental $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the final payment of CL&P's RRBs. In its decision, PURA also maintained CL&P's authorized distribution segment regulatory ROE of 9.4 percent. In 2011, CL&P earned a distribution segment regulatory ROE of 9.4 percent, compared to 7.9 percent in 2010.

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

CL&P has a transmission adjustment clause as part of its retail distribution rates, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, thereby recovering all of its transmission expenses on a timely basis.

CL&P, jointly with UI, has entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects being built or modified and one demand response project. The capacity CfDs extend through 2026 and obligate the utilities to pay the difference between a set price and the value that the projects receive in the ISO-NE markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI, whereby UI will have a 20 percent share of the costs and benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy to serve its SS and LRS loads from a variety of competitive sources through periodic requests for proposals. CL&P enters into supply contracts for SS periodically for periods of up to three years to mitigate the risks associated with energy price volatility for its residential and small and medium load commercial and industrial customers. CL&P enters into supply contracts for LRS for larger commercial and industrial customers every three months. Currently, CL&P has contracts in place with various suppliers for all of its SS loads through 2012, and 40 percent of expected load for 2013. CL&P's contracts for its LRS loads extend through the second quarter of 2012.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE – DISTRIBUTION

PSNH's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2011, PSNH furnished retail franchise electric service to approximately 498,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of primarily fossil fueled electricity generation plants. Included in those electric generating plants is PSNH's 50 MW wood-burning Northern Wood Power Project at its Schiller Station in Portsmouth, New Hampshire, and approximately 70 MW of hydroelectric generation. PSNH's distribution segment includes the activities of its generation business.

The Clean Air Project, a wet scrubber project, was constructed and placed in service by PSNH at its Merrimack Station in September 2011. The cost of the project will be recovered through PSNH's ES rates under New Hampshire law. By November 2011, both of Merrimack station's coal-fired units were integrated with the scrubber, and the scrubber is now reducing emissions from the units. PSNH expects to complete remaining project construction activities in mid-2012. We currently expect the final costs of the project to be approximately $422 million.

The following table shows the sources of PSNH's 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	54
Commercial	35
Industrial	8
Other	3
Total	100%

Rates

PSNH is subject to regulation by the 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 ES rate recovers its generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs, including above-market expenses incurred under mandated power purchase obligations 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. PSNH recovers the costs of these RRBs through the SCRC rate. The amount of the RRB obligation decreases each quarter and the RRBs are scheduled to be retired as of May 1, 2013.

On an annual basis, PSNH files with the NHPUC an ES/SCRC cost reconciliation filing for the preceding year. The difference between revenues and costs are included in the ES/SCRC rate calculations and refunded to or recovered from customers in the subsequent period approved by the NHPUC.

The TCAM allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted on July 1 of each year.

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement of PSNH's rate case allowing a net distribution rate increase of $45.5 million on an annualized basis effective July 1, 2010, an annualized distribution rate decrease of $2.4 million effective July 1, 2011 and projected increases of $9.5 million and $11.1 million on July 1, 2012 and 2013, respectively. If PSNH's 12-month trailing average regulatory ROE is greater than 10 percent, amounts over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent. PSNH's distribution segment regulatory ROE was 9.7 percent (including generation) in 2011, compared to 10.2 percent in 2010.

In March 2011, PSNH filed with the NHPUC to collect certain exogenous costs, step increases, and storm costs, as permitted by its 2010 rate case settlement. These rate increases were offset by the scheduled termination, on June 30, 2011, of a rate recoupment charge, also from the 2010 rate case settlement. During the second quarter of 2011, the NHPUC issued rate orders approving net increases in revenue requirements effective July 1, 2011 to (1) recover exogenous costs, (2) implement a step increase program for capital additions and the reliability enhancement program, and (3) allow for the recovery of the 2010 windstorm costs. Together with the scheduled termination of the rate recoupment charge, the net impact of these rate changes was a $2.4 million decrease in rates effective July 1, 2011.

Under New Hampshire law, all of PSNH's customers are entitled to choose competitive energy suppliers, with PSNH providing default energy service under its ES rate for those customers who do not elect to use a third party supplier. Prior to 2009, PSNH experienced only a minimal amount of customer migration. However, customer migration levels began to increase significantly in 2009 as energy costs decreased from their historic high levels and competitive energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. By the end of 2011, approximately 2.6 percent of all of PSNH's customers (approximately 36 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs of PSNH's generation assets must be spread over a smaller group of customers and lower sales volume. The customers that did not choose a third party supplier, predominately residential and small commercial and industrial customers, are now paying a larger proportion of these fixed costs. On July 26, 2011, the NHPUC ordered PSNH to file a rate proposal that would mitigate the impact of customer migration expected to occur when the ES rate is higher than market prices. On January 26, 2012, the NHPUC rejected the PSNH proposal and ordered PSNH to file a new proposal, no later than June 30, 2012, addressing certain issues raised by the NHPUC.

PSNH cannot predict if the upward pressure on ES rates due to customer migration will continue into the future, as future migration levels are dependent on market prices and supplier alternatives. If future market prices once more exceed the average ES rate level, some or all of these customers on third party supply may migrate back to PSNH.

On November 22, 2011, the NHPUC opened a docket to consider the in-service status of the Clean Air Project, the appropriate rate treatment, PSNH's prudence in construction of the project and the propriety of setting temporary rates. Hearings on temporary rates are scheduled for March 12 and 13, 2012. Following hearings on temporary rates, it is expected that recovery of costs of the Clean Air

Project will begin during the second quarter of 2012. No formal schedule for the comprehensive prudence review or for permanent rates has been established.

Sources and Availability of Electric Power Supply

During 2011, approximately 72 percent of PSNH's load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with third parties. The remaining 28 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 2012 in a similar manner. Included in the 72 percent above are PSNH obligations to purchase power from approximately two dozen IPPs, the output of which it either uses to serve its customer load or sells into the ISO-NE market.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO's distribution business consists primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers. As of December 31, 2011, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western region of Massachusetts. WMECO does not own any fossil or hydro-electric generating facilities and purchases its energy requirements from competitive suppliers. In 2009, pursuant to the Massachusetts Green Communities Act, WMECO was authorized to install 6 MW of solar energy generation in its service territory. In October 2010, WMECO completed development of a 1.8 MW solar generation facility on a site in Pittsfield, Massachusetts and in December 2011 completed development of a 2.3 MW solar generation facility in Springfield, Massachusetts. WMECO is continuing to evaluate sites suitable for development of the remaining 1.9 MW of the authorized 6 MW of capacity. WMECO will sell all energy and other products from its solar generation facilities into the ISO-NE market.

The following table shows the sources of WMECO's 2011 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	57
Commercial	34
Industrial	11
Other	(2)
Total	100%

Rates

WMECO is subject to regulation by the 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, acquisition of 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 recover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under Massachusetts law, all of WMECO's customers are entitled to choose their energy suppliers, while WMECO remains their distribution company. WMECO purchases power from competitive suppliers 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 small commercial and industrial customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and industrial customers have switched to a competitive energy supplier.

WMECO continues to supply approximately 53 percent of its customer load at basic service rates while the other 47 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on WMECO's delivery business or its operating income.

The DPU has approved a number of individual cost and revenue requirement recovery mechanisms over the years. These individual mechanisms recover costs associated with providing energy, retail transmission of energy, administrative costs to procure energy, bad debt costs associated with providing energy, company investments in renewable energy such as solar generation, and credits given to customers who generate renewable energy. There is also a mechanism for the recovery of stranded generation costs as a result of the 1999 electric restructuring act in Massachusetts. Additionally the DPU has provided cost and revenue requirement recovery mechanisms for certain operating expenses. These individual mechanisms include recovery of employee pension and post-retirement health benefit costs, certain state government regulatory review, energy efficiency programs, customer arrearage forgiveness programs and low income customer discounts. In WMECO's January 31, 2011 rate decision, WMECO received approval for a revenue decoupling reconciliation mechanism that provides assurance that WMECO will recover a DPU pre-established level of baseline distribution delivery service revenue to manage all other distribution operating expenses and earn a level of return on its capital investment. The reconciliation mechanisms noted above are trued up on an annual basis producing deferrals for future recovery.

Distribution Rates: On January 31, 2011, the DPU issued a final decision in WMECO's July 2010 rate application, authorizing a $16.8 million annualized rate increase in distribution revenues and an allowed regulatory ROE of 9.6 percent effective February 1, 2011. The DPU also authorized WMECO's request to recover certain active hardship account balances, the recovery of certain storm costs over five years and a full decoupling mechanism, whereby actual revenue billed by WMECO is reconciled with WMECO's target revenue on an annual basis. The DPU did not authorize rate recovery of a proposed $20 million average increase in WMECO's capital spending plan. WMECO's distribution segment regulatory ROE was 9 percent in 2011, compared to 4.6 percent in 2010.

WMECO is subject to service quality (SQ) metrics that measure safety, reliability and customer service, and WMECO pays any charges incurred for failure to meet such metrics to customers. WMECO will not be required to pay an assessment charge for its 2011 performance results as WMECO performed at or above its target for all of its SQ metrics in 2011.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets (other than its recently developed solar generation) and purchases its energy requirements from a variety of competitive sources through requests for proposals issued periodically, consistent with DPU regulations. WMECO enters into supply contracts for basic service for 50 percent of its residential and small commercial and industrial customers twice a year for twelve month terms. WMECO enters into supply contracts for basic service for 100 percent of large commercial and industrial customers every three months.

REGULATED GAS DISTRIBUTION – YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 208,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in 2011 was approximately 55 Bcf. Yankee Gas provides firm natural gas sales service to retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on gas for heating, hot water and cooking needs, and commercial and industrial customers who choose to purchase natural gas from Yankee Gas. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which is used primarily to assist it in meeting its supplier-of-last-resort obligations and also enables it to make economic purchases of natural gas, which typically occur during periods of low demand.

Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas' service territory buy gas supply and delivery only from Yankee Gas while commercial and industrial customers may choose their gas suppliers. Yankee Gas 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 commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice, for whom Yankee Gas can interrupt service during peak demand periods or at any other time to maintain distribution system integrity.

The following table shows the sources of 2011 natural gas operating revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	50
Commercial	30
Industrial	17
Other	3
Total	100%

A summary of firm natural gas sales in million cubic feet for Yankee Gas for 2011 and 2010 and the percentage changes in 2011, as compared to 2010 on an actual and weather normalized basis (using a 30-year average) is as follows:

	For the Year Ended December 31, 2011 Compared to 2010			
	Sales (million cubic feet) (1)			Weather Normalized Percentage Increase/
Firm Natural Gas	**2011**	**2010**	**Percentage Increase**	**(Decrease)**
Residential	13,508	13,403	0.8%	(3.2)%
Commercial	17,175	15,137	13.5%	9.8%
Industrial	16,197	14,866	8.9%	8.0%
Total	46,880	43,406	8.0%	5.1%
Total, Net of Special Contracts (2)	38,197	35,038	9.0%	5.4%

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

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

Our firm natural gas sales are subject to many of the same influences as are our retail electric sales, but have benefitted from migration of interruptible customers switching to firm service rates and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in 2011 were 8 percent higher than 2010. Colder weather, especially in the first quarter of 2011, was a contributing factor to the higher sales. Heating degree days for 2011 in Connecticut were 6.4 percent higher than 2010. On a weather normalized basis, actual firm natural gas sales in 2011 were 5.1 percent higher than 2010.

In November 2011, Yankee Gas completed construction of its WWL project, a 16-mile natural gas pipeline between Waterbury and Wallingford, Connecticut and an increase of vaporization output of its LNG plant. Construction on the project began in April 2010 and total costs were approximately $54 million.

Rates

Yankee Gas is subject to regulation by PURA, 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, affiliate transactions, management efficiency and construction and operation of distribution, production and storage facilities.

Distribution Rates: On June 29, 2011 PURA issued a final decision in Yankee Gas' rate proceeding, which it amended in September 2011. The final amended decision approved a regulatory ROE of 8.83 percent, based on a capital structure of 52.2 percent common equity and 47.8 percent debt, approved the inclusion in rates of costs associated with the WWL project, and also allowed for a substantial increase in annual spending for bare steel and cast iron pipe replacement, as requested by Yankee Gas. Yankee Gas' regulatory ROE was 9.3 percent in 2011, as compared to 8.6 percent in 2010.

Sources and Availability of Natural Gas Supply

PURA requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its supply portfolio to meet firm customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which is used primarily to assist the company in meeting its supplier-of-last-resort obligations and also enables Yankee Gas to make economic purchases of natural gas, typically in periods of low demand. Yankee Gas' on-system stored LNG and underground storage supplies help to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate capacity from the three interstate pipelines that directly serve Connecticut: the Algonquin, Tennessee and Iroquois Pipelines. Yankee Gas has long-term firm contracts for capacity on TransCanada Pipelines Limited Pipeline, Vector Pipeline, L.P., Tennessee Gas Pipeline, Iroquois Gas Transmission Pipeline, Algonquin Pipeline, Union Gas Limited, Dominion Transmission, Inc., National Fuel Gas Supply Corporation, Transcontinental Gas Pipeline Company, and Texas Eastern Transmission, L.P. pipelines. Yankee Gas considers these transportation arrangements adequate for its needs.

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 of all market participants, has served since 2005 as the regional transmission organization of the New England transmission system. ISO-NE works to ensure the reliability of the system, administers, subject to FERC approval, the independent system operator tariff, oversees the efficient and competitive functioning of the regional wholesale power market and determines which costs of all regional major transmission facilities are shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through formula rates that are approved by the FERC. Our transmission revenues are recovered from New England customers through charges that recover costs of transmission and other transmission-related services provided by all regional transmission owners, with a portion of those revenues collected from the distribution segments of CL&P, PSNH and WMECO. These rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The difference between estimated and actual costs is deferred for future recovery from, or refunded to, transmission customers.

FERC ROE Proceedings

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. Beginning in 2009, the ROE for all regional transmission investment approved by ISO-NE is 11.64 percent, which includes the 50 basis points for joining the regional transmission organization. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects and WMECO earns 12.89 percent on the Massachusetts portion of GSRP. All appeals of FERC's incentive ROE orders for New England transmission owners have been denied.

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

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

As of December 31, 2011, CL&P, PSNH, and WMECO had approximately $1.5 billion of aggregate shareholder equity invested in their transmission facilities. As a result, each 10 basis point change in the authorized base ROE would change annual consolidated earnings by approximately $1.5 million.

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

Transmission Projects

NEEWS

CL&P and WMECO are continuing to develop and construct the NEEWS project, which is comprised of GSRP, the Interstate Reliability Project and the Central Connecticut Reliability Project, and is estimated to cost $1.3 billion in the aggregate.

CL&P and WMECO commenced substation construction on GSRP, the largest project in NEEWS, in December 2010 and began full construction in Connecticut and Massachusetts in late 2011. GSRP was approximately 50 percent complete as of December 31, 2011 and we expect it to be placed in service in late 2013 at a cost of approximately $718 million.

CL&P is designing and building the Interstate Reliability Project in coordination with National Grid USA, whose segment of this phase will interconnect with CL&P's at the Connecticut-Rhode Island border. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project. CL&P filed its siting applications in late 2011 and approvals are expected in late 2013, with construction commencing in late 2013 or early 2014. We expect the project will be placed in service in late 2015 and that CL&P's share of the costs will be $218 million.

The Central Connecticut Reliability Project, which involves construction of a new 345 KV overhead line from Bloomfield, Connecticut to Watertown, Connecticut at a cost of $301 million, is the third major part of NEEWS. In March 2011, ISO-NE announced that it would review the Central Connecticut Reliability Project along with other central Connecticut projects as part of a study known as the Greater Hartford Central Connecticut Study. We expect ISO-NE to issue preliminary need results and transmission solutions in 2013.

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

Northern Pass Transmission Line Project

NPT is a limited liability company jointly owned by NU and NSTAR to construct, own and operate the Northern Pass transmission line, a planned HVDC transmission line from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. Northern Pass will interconnect at the Québec/New Hampshire border with a planned HVDC transmission line being developed by HQ. NUTV, a subsidiary of NU, holds a 75 percent interest in NPT, with NSTAR Transmission Ventures, Inc., a subsidiary of NSTAR, holding the remaining 25 percent. We currently estimate that our 75 percent share of the costs to build the Northern Pass transmission project will be approximately $830 million out of total expected costs of approximately $1.1 billion (including capitalized AFUDC).

Under a TSA between NPT and Hydro Renewable Energy, a subsidiary of HQ, NPT will sell to Hydro Renewable Energy 1,200 MW of firm electric transmission rights over the Northern Pass for a 40-year term and charge cost-based rates. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project and, during commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent. During the development and construction phases under the TSA, NPT will record non-cash AFUDC earnings. On March 18, 2011, the NHPUC filed a request with the FERC seeking rehearing on the ROE granted to Northern Pass. On August 5, 2011, FERC denied the request by the NHPUC.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE seeking permission for NPT to construct and maintain facilities that cross the U.S. border. The DOE held seven meetings in New Hampshire in mid-March 2011 seeking public comment. In response to concerns raised at these meetings, NPT revised its application to request additional time during the public comment period to allow NPT to review alternative routes. On June 15, 2011, the DOE extended the scoping comment period for at least forty-five days after NPT files an alternative route with the DOE. After the final route has been identified, certain environmental studies will need to be completed in order to obtain DOE permits. We expect to commence construction in 2014 and place the project in service in the fourth quarter of 2016.

On February 8, 2012, the New Hampshire legislature passed a bill that could potentially prohibit the use of eminent domain for the development of any "non-reliability" electric transmission projects such as Northern Pass. The bill is currently awaiting action by the Governor. We are reviewing the potential impact of the bill on NPT, should it be enacted, including its effect on the project's route, cost and schedule. We believe that NPT will be able to acquire the necessary rights along an acceptable route, which would make it feasible to construct the project even if the bill is enacted. Given the ultimate design needs of the project, along with siting and permit requirements, which will vary depending upon the route ultimately selected, there is a possibility for further delay in commencement of construction.

Other Transmission Transactions

On May 31, 2011, CL&P and the Connecticut Transmission Municipal Electric Energy Cooperative (CTMEEC), a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric utilities, completed the sale by CL&P to CTMEEC of a segment of high voltage transmission lines built by CL&P in the town of Wallingford, Connecticut. The assets were sold at their net book value of $42.5 million, plus reimbursement of closing costs. CL&P is operating and maintaining the lines under an agreement with CTMEEC. The transaction did not include the transfer of land or equipment unrelated to electric transmission service.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects generally enter rate base after they are placed in commercial operation. At the end of 2011, our transmission rate base was approximately $2.96 billion, including approximately $2.1 billion at CL&P, $390 million at PSNH and $467 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.8 billion by the end of 2016, including approximately $804 million at NPT.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding our existing electric transmission, distribution and generation systems and our natural gas distribution system. Our consolidated capital expenditures in 2011 totaled approximately $1.2 billion, essentially all of which was expended by the Regulated companies. The 2012 capital expenditures of these companies are estimated to total approximately $1.14 billion, $500 million by CL&P, $212 million by PSNH, $251 million by WMECO, $40 million by NPT, and $94 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 we expect to become committed projects in 2012.

In 2011, CL&P's transmission capital expenditures totaled $128.6 million, and its distribution capital expenditures totaled $338.5 million. For 2012, CL&P projects transmission capital expenditures of $174 million and distribution capital expenditures of $315 million. During the period 2012 through 2016, CL&P plans to invest approximately $837 million in transmission projects, the majority of which will be for NEEWS, and $1.42 billion on distribution projects. In addition, CL&P expects to spend $11 million on regulated generation in 2012, and a total of $45 million during the period 2012 through 2016. If all of the transmission and distribution projects are built as proposed, CL&P's rate base for transmission assets is projected to increase from approximately $2.1 billion at the end of 2011 to approximately $2.45 billion by the end of 2016, and its rate base for electric distribution is projected to increase from approximately $2.6 billion to approximately $3.11 billion over the same period.

In 2011, PSNH's transmission capital expenditures totaled $68.1 million, its distribution capital expenditures totaled $98.8 million and its generation capital expenditures totaled $124.8 million. For 2012, PSNH projects transmission capital expenditures of $66 million, distribution capital expenditures of $112 million and generation capital expenditures of $34 million. During the period 2012 through 2016, PSNH plans to spend $468 million on transmission projects, $560 million on distribution projects, and $159 million on generation projects. If all of the transmission, distribution and generation projects are built as proposed, PSNH's rate base for electric transmission is projected to increase from $390 million at the end of 2011 to $721 million by the end of 2016, and its rate base for distribution and generation assets is projected to increase from approximately $1.6 billion to approximately $1.76 billion over the same period.

In 2011, WMECO's transmission capital expenditures totaled $236.8 million, its distribution capital expenditures totaled $41.8 million and solar generation expenditures were $11.7 million. In 2012, WMECO projects transmission capital expenditures of $193 million, distribution capital expenditures of $39 million and expenditures of $19 million on solar generation. During the period 2012 through 2016, WMECO plans to spend $510 million on transmission projects, with the bulk of that amount to be spent on GSRP, $199 million on distribution projects and $49 million on solar generation. If all of the transmission, distribution and generation projects are built as proposed, WMECO's rate base for electric transmission is projected to increase from $467 million at the end of 2011 to $814 million by the end of 2016 and its rate base for distribution and generation assets is projected to increase from $441 million to $498 million over the same period.

In addition, we project transmission capital expenditures by NPT of $40 million in 2012 and during the period 2012 through 2016, we project NPT to spend $812 million on Northern Pass.

In 2011, Yankee Gas capital expenditures totaled $102.8 million. For 2012, Yankee Gas projects total capital expenditures of $94 million, of which $26 million is expected to be related to basic business activities such as relocation of conflicting gas facilities and the purchase of meters, tools and information technology, $48 million related to reliability improvements, and $20 million for load growth and new business requests. During the period 2012 through 2016, Yankee Gas plans on making $564 million of capital expenditures. Future capital spending will likely be affected by price differences between the cost of natural gas and home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements. Excluding non-recurring major projects, NU expects that approximately 25 percent of Yankee Gas' capital expenditures over the 2012 through 2016 period will be related to basic business activities, approximately 30 percent will be related to load growth and new business, and approximately 45 percent will be related to reliability initiatives and infrastructure. If all of Yankee Gas' projects are built as proposed, Yankee Gas' rate base is projected to increase from $754 million at the end of 2011 to approximately $1.04 billion by the end of 2016.

FINANCING

On April 1, 2011, CL&P completed the remarketing of $62 million of tax-exempt secured PCRBs, which mature on May 1, 2031. The PCRBs carry a coupon rate of 1.25 percent until April 1, 2012, at which time CL&P expects to remarket the bonds.

On May 26, 2011, PSNH issued $122 million of first mortgage bonds with a coupon rate of 4.05 percent and a maturity date of June 1, 2021, and used the proceeds to redeem $119.8 million of tax-exempt 1992 Series D and 1993 Series E PCRBs, each with a maturity date of May 1, 2021 and a coupon rate of 6 percent. The refinancing is expected to reduce PSNH's interest costs by approximately $2.2 million in 2012.

On September 13, 2011, PSNH issued $160 million of first mortgage bonds, due September 1, 2021, with a coupon rate of 3.20 percent, and on September 16, 2011, WMECO issued $100 million of senior unsecured notes due September 15, 2021 carrying a coupon rate of 3.50 percent.

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

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH, WMECO and Yankee Gas, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All such companies currently are, and expect to remain in compliance with these covenants.

In 2012, in addition to remarketing the $62 million PCRBs at CL&P, NU parent has a debt maturity on April 1, 2012 of $263 million, which NU expects to refinance with proceeds of a new debt issuance, and Yankee Gas has an annual sinking fund requirement of $4.3 million. Also, in 2012, we expect to issue $150 million of long-term debt comprised of $100 million by WMECO and $50 million by Yankee Gas in the second half of 2012.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective generation 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 CL&P, PSNH and WMECO and several other New England utilities. 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
CYAPC	34.5%	5.0%	9.5%	49.0%
MYAPC	12.0%	5.0%	3.0%	20.0%
YAEC	24.5%	7.0%	7.0%	38.5%

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

OTHER REGULATORY AND ENVIRONMENTAL MATTERS

General

We are regulated in virtually all aspects of our business by various federal and state agencies, including 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 PURA, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has 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, 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 approximately 1,200 MW of generation assets. In 2011, PSNH's Clean Air Project, the installation of a wet flue gas desulphurization system at its Merrimack coal station to reduce its mercury and sulfur dioxide emissions, was placed into service. The Clean Air Project is expected to be fully operational in mid-2012 and is designed to capture more than 80 percent of the mercury in the coal from the coal burning stations and to reduce sulfur dioxide emissions by more than 90 percent, making Merrimack one of the cleanest coal-burning plants in the nation. We expect the final costs of the project to be approximately $422 million. Compliance with additional environmental laws and regulations, particularly air and water pollution control requirements, may cause changes in operations or require further investments in new equipment at existing facilities.

Water Quality Requirements

The Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a NPDES permit from the EPA 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. In each of the last three years, the costs incurred by PSNH related to compliance with NPDES and state discharge permits have not been material.

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

Air Quality Requirements

The Clean Air Act Amendments (CAAA), as well as New Hampshire law, impose stringent requirements on emissions of SO_2 and NO_X for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Requirements for the installation of continuous emissions monitors and expanded permitting provisions also are included.

In December 2011, the EPA finalized the Mercury and Air Toxic Standards (MATS) that require the reduction of emissions of hazardous air pollutants from new and existing coal- and oil-fired electric generating units. Commonly called the Utility MACT (maximum achievable control technology) rules, it establishes emission limits for mercury, arsenic and other hazardous air pollutants from coal- and oil-fired units. MATS is the first implementation of a nationwide emissions standard for hazardous air pollutants across all electric generating units and provides utility companies with up to five years to meet the requirements. PSNH owns and operates approximately 1,000 MW of fossil fueled electric generating units subject to MATS, including the Merrimack, Newington and Schiller stations. We believe the Clean Air Project at our Merrimack Station, together with existing equipment, will enable the facility to meet the MATS requirements. A review of the potential impact of MATS on our other PSNH units is not yet complete. Additional controls may be required at these facilities. To date, the financial impact of these potential controls has not been determined.

In New Hampshire, the Multiple Pollutant Reduction Program capped NO_X, SO_2 and CO_2 emissions beginning in 2007. In addition, a 2006 New Hampshire law required PSNH to install a wet flue gas desulphurization system to reduce mercury emissions of its coal fired plants by at least 80 percent from all PSNH coal fired stations (with the co-benefit of reductions in SO_2 emissions as well). The Clean Air Project enables PSNH to satisfy this requirement.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by nine northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fueled electric generating plants. Because CO_2 allowances issued by any participating state are usable across all nine RGGI state programs, the individual state CO_2 trading programs, in the aggregate, form one regional compliance market for CO_2 emissions. A regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period that began in 2009.

Because neither CL&P nor WMECO currently own any generating assets (other than the solar facilities owned by WMECO, which do not emit CO_2), neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators that provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs are then recoverable from customers.

NU's carbon emission inventory accounts for and reports all direct carbon dioxide (CO_2) methane (CH_4) nitrous oxide (N_2O) sulfur hexafluoride (SF_6) emissions for operations of NU and its subsidiaries in carbon dioxide equivalents. Total carbon emissions include those from sources owned or operated by NU (Scope 1) and those that are a consequence of NU's activities, but occur from sources owned or controlled by others, such as emissions from purchased electricity and line loss during the transmission and distribution of electricity (Scope 2). NU emissions expressed in thousand metric tons of carbon dioxide equivalent (CO_2–e) for NU and its system companies for 2008 through 2010 are shown below.

	2010	2009	2008
Total CO_2–e emissions (excludes CO_2 from biomass and biofuels)	3,976	3,930	5,131

Data was collected and calculated using the World Resource Institute greenhouse gas protocol tools except for stationary combustion emissions associated with electric generating units where more accurate Continuous Emissions Monitoring System data was available. EPA reporting protocol was used for generation calculations where applicable.

PSNH anticipates that its generating units will emit between four million and five million tons of CO_2 per year excluding emissions from the operation of PSNH's Northern Wood Power Project. Under the RGGI formula, the Northern Wood Power Project 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 provided up to 2.5 million banked CO_2 allowances per year for PSNH's fossil fueled electric generating plants during the 2009 through 2011 compliance period. These banked CO_2 allowances initially comprised approximately one–half of the yearly CO_2 allowances required for PSNH's generating plants for compliance with RGGI. 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 secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers.

Each of the states in which we do business also has RPS requirements, which generally require fixed percentages of our energy supply to come from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources.

New Hampshire's RPS provision requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2011, the total RPS obligation was 9.58 percent and it will ultimately reach 23.8 percent in 2025. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses a portion of internally generated RECs and purchased RECs to meet its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes up the difference between the RECs purchased and its total obligation by making an alternative compliance payment for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments are recovered by PSNH through its ES rates charged to customers.

The RECs generated from PSNH's Northern Wood Power Project, a wood–burning facility, are sold to other energy suppliers and the proceeds from the sale of these RECs is credited back to customers.

Similarly, Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2011, the total RPS obligation was 15 percent and will ultimately reach 27 percent in 2020. CL&P is permitted to recover any costs incurred in complying with RPS from its customers through rates.

Massachusetts' RPS program also requires electricity suppliers to meet renewable energy standards. For 2011, the requirement was 15.1 percent, and will ultimately reach 27.1 percent in 2020. WMECO is permitted to recover any costs incurred in complying with RPS from its customers through rates.

Hazardous Materials Regulations

Prior to the last quarter of the 20th century when environmental best practices and laws were implemented, utility companies often disposed of residues from operations by depositing or burying them on–site or disposing of them at off–site landfills or other facilities. Typical materials disposed of include coal gasification byproducts, fuel oils, ash, and other materials that might contain polychlorinated biphenyls or that otherwise might be hazardous. 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, based upon currently available information, is our estimated environmental investigation and/or remediation costs for waste disposal sites for which we expect to bear legal liability. We 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 these practices. As of December 31, 2011, the liability recorded by us for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $31.7 million, representing 59 sites. These costs could be significantly higher if remediation becomes 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 MGP facilities. These facilities were owned and operated by our predecessor companies 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.

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

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from 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.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government. The EPA initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector. The EPA has mandated GHG emission reporting beginning in 2011 for emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF-6 gas and methane.

We are continually evaluating the regulatory risks and regulatory uncertainty presented by climate change concerns. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal "cap and trade" laws, carbon taxes, fuel and energy taxes, or regulations requiring additional capital expenditures at our generating facilities. Product efficiency standards and regulations could impact the demand for energy use by our customers. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers.

FERC Hydroelectric Project Licensing

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, (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 a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act 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.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision that 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. PSNH is not presently encountering any of these challenges.

EMPLOYEES

As of December 31, 2011, we employed a total of 6,063 employees, excluding temporary employees, of which 1,828 were employed by CL&P, 1,243 were employed by PSNH, 346 were employed by WMECO, 413 were employed by Yankee Gas and 2,228 were employed by NUSCO. Approximately 2,279 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers or The United Steelworkers and 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 EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), 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, 56 Prospect Street, Hartford, CT 06103.

Item 1A.
Risk Factors

In addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" included immediately prior to Item 1, *Business,* above, we are subject to a variety of significant risks. 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 actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our Regulated companies charge their respective retail and wholesale customers are determined by their state utility commissions and by FERC. These commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. FERC also regulates their transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters. The commissions' policies and regulatory actions could have a material impact on the Regulated companies' financial position, results of operations and cash flows.

Our transmission, distribution and generation systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows.

Our ability to properly operate our transmission, distribution and generation systems is critical to the financial performance of our business. Our transmission, distribution and generation businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age); labor disputes; disruptions in the delivery of electricity, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; information security risk, such as a breach of our systems on which sensitive utility customer data and account information are stored; catastrophic events such as fires, explosions, or other similar occurrences; extreme weather conditions beyond equipment and plant design capacity; and other unanticipated operations and maintenance expenses and liabilities. The failure of our transmission, distribution and generation systems to operate as planned may result in increased capital costs, reduced earnings or unplanned increases in operation and maintenance costs. At PSNH, outages at generating stations may be deemed imprudent by the NHPUC resulting in disallowance of replacement power costs. Such costs that are not recoverable from our customers would have an adverse effect on our financial position, results of operations and cash flows.

Limits on our access to and increases in the cost of capital may adversely impact our ability to execute our business plan.

We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. In addition, higher interest rates would increase our cost of borrowing, which could adversely impact our results of operations. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses.

Our counterparties may not meet their obligations to us or may elect to exercise their termination rights, which would adversely affect our earnings.

We are exposed to the risk that counterparties to various arrangements who owe us money, have contracted to supply us with energy, coal, or other commodities or services, or who work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations, will terminate such arrangements or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations or terminate such arrangements, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of, or cancel a capital project. Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected.

Difficulties in obtaining necessary rights of way, or siting, design or other approvals for major transmission projects, environmental concerns or actions of regulatory authorities, communities or strategic partners may cause delays or cancellation of such projects, which would adversely affect our earnings.

Various factors could result in increased costs or result in delays or cancellation of our transmission projects. These include the regulatory approval process, environmental and community concerns, design and siting issues, difficulties in obtaining required rights of way and actions of strategic partners. Should any of these factors result in such delays or cancellations, our financial position, results of operations, and cash flows could be adversely affected.

Economic events or factors, changes in regulatory or legislative policy and/or regulatory decisions or construction of new generation may delay completion of or displace or result in the abandonment of our planned transmission projects or adversely affect our ability to recover our investments or result in lower than expected earnings.

Our transmission construction plans could be adversely affected by economic events or factors, new legislation, regulations, or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions. Any of such events could cause delays in, or the inability to complete or abandonment of, economic or reliability related projects, which could adversely affect our ability to achieve forecasted earnings or to recover our investments or result in lower than expected rates of return. Recoverability of all such investments in rates may be subject to prudence review at the FERC. While we believe that all of such costs have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, our transmission projects may be delayed or displaced by new generation facilities, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

Many of our transmission projects are expected to help alleviate identified reliability issues and reduce customers' costs. However, if, due to economic events or factors or further regulatory or other delays, the in-service date for one or more of these projects is delayed, there may be increased risk of failures in the electricity transmission system and supply interruptions or blackouts, 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. Our projected earnings and growth could be adversely affected were FERC to reduce these incentives in the future below the levels presently anticipated.

Increases in electric and gas prices and/or a weak economy, can lead to changes in legislative and regulatory policy promoting energy efficiency, conservation, and self-generation and/or a reduction in our customers' ability to pay their bills, which may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. 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, a period of prolonged economic weakness could impact customers' ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses or other adverse effects on our financial position, results of operations or cash flows.

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

The existing FERC-approved New England transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with a FERC approved formula found in the transmission tariff. All New England transmission owners' agreement to this regional cost allocation is set forth in the Transmission Operating Agreement. This agreement can be modified with the approval of a majority of the transmission owning utilities and approval by FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the rates our distribution companies charge their retail customers.

FERC has issued rules requiring all regional transmission organizations and transmission owning utilities to make compliance changes to their tariffs and contracts in order to further encourage the construction of transmission for generation, including renewable generation. This compliance will require ISO-NE and New England transmission owners to develop methodologies that allow for regional planning and cost allocation for transmission projects chosen in the regional plan that are designed to meet public policy goals such as reducing greenhouse gas emissions or encouraging renewable generation. Such compliance may also allow non-incumbent utilities and other entities to participate in the planning and construction of new projects in our service area and regionally.

Changes in the Transmission Operating Agreement, the New England Transmission Tariff or legislative policy, or implementation of these new FERC planning rules, could adversely affect our transmission planning, our earnings and our prospects for growth.

Changes in regulatory or legislative policy or unfavorable outcomes in regulatory proceedings could jeopardize our full and/or timely recovery of costs incurred by our regulated distribution and generation businesses.

Under state law, our Regulated 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 such costs incurred by our Regulated companies, such as for construction, operation and maintenance, as well as a return on investment on their respective regulated assets, including the construction costs incurred by PSNH for the Clean Air Project at its Merrimack Station. PSNH's expenditures for the project are subject to prudence review by the NHPUC. The amount of costs incurred by the Regulated companies, coupled with increases in fuel and energy prices, could lead to consumer or regulatory resistance to the timely recovery of such costs, thereby adversely affecting our financial position, results of operations or cash flows.

Additionally, state legislators may enact laws that significantly impact our Regulated companies' revenues, including by mandating electric or gas rate relief and/or by requiring surcharges to customer bills to support state programs not related to the utilities or energy policy. Such increases could pressure overall rates to our customers and our routine requests to regulators for rate relief.

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

PSNH meets most of its energy requirements through its own generation resources and fixed-price forward purchase contracts. PSNH's remaining energy needs are met primarily through spot market 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 energy to meet its 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.

Migration of customers from PSNH energy service to competitive energy suppliers is increasing the cost to the remaining customers of energy produced by PSNH generation assets and decrease our revenues.

PSNH's ES rates have been higher than competitive energy prices offered to some customers in recent years, due primarily to lower natural gas prices. Further increases are expected as the costs associated with the Clean Air Project are fully phased into rates. The remaining retail energy service customers are experiencing an increase in PSNH's ES rate by 5 percent to 7 percent due to migration of large commercial and industrial customers and the lower base in which to recover PSNH's fixed generation costs. This increase may in turn cause further migration and further increasing of PSNH ES rates. This trend could lead to PSNH continuing to lose retail customers and increasing the burden of supporting the cost of its generation facilities on remaining customers and being unable to support the cost of its generation facilities through an ES rate.

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

Pursuant to New Hampshire law, PSNH placed the Clean Air Project in service at its Merrimack Station in Bow, New Hampshire. PSNH's recovery of costs in constructing the project is subject to prudence review by the NHPUC. A material prudence disallowance could adversely affect PSNH's financial position, results of operations or cash flows. While we believe we have prudently incurred all expenditures to date, we cannot predict the outcome of any prudence reviews. 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 position 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 have developed 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, acts of war or terrorism, or cyber breaches could negatively impact our business.

Because our generation and transmission facilities are part of an interconnected regional grid, we face the risk of blackout due to a disruption on a neighboring interconnected system.

Acts of war or terrorism could target our generating, transmission and distribution facilities or our data management systems. Such actions could impair our ability to manage these facilities or operate our system effectively, resulting in loss of service to customers.

In addition, cyber intrusions targeting our information systems could impair our ability to properly manage our data, networks, systems and programs, adversely affect our business operations or lead to release of confidential customer information or critical operating information. While we have implemented measures designed to prevent cyber-attacks and mitigate their effects should they occur, our systems are vulnerable to unauthorized access and cyber intrusions. We cannot discount the possibility that a security breach may occur or quantify the potential impact of such an event.

Any such grid disturbances, acts of war or terrorism, or cyber breaches could result in a significant decrease in revenues, significant expense to repair system damage or security breaches, and liability claims, which could have a material adverse impact on our financial position, results of operations or cash flows.

Severe storms could cause significant damage to our electrical facilities requiring extensive capital expenditures, the recovery for which is subject to approval by regulators.

Severe weather, such as Tropical Storm Irene in August 2011 and the October 29, 2011 snowstorm, and other such major natural disasters, could cause widespread damage to our transmission and distribution facilities. The resulting cost of repairing damage to our facilities and the potential disruption of our operations could exceed our financial reserves and insurance.

Tropical Storm Irene and the October 2011 snowstorm caused significant damage to our transmission and distribution systems. As a result, we have recorded $312 million (predominantly at CL&P) for estimated restoration costs as regulatory assets, subject to future recovery from customers. If, upon review, any of our state regulatory authorities finds that our actions were imprudent, some of those restoration costs may not be recoverable from customers. The inability to recover a significant amount of such costs could have an adverse effect on our financial position, results of operations and cash flows.

Market performance or changes in assumptions require us to make significant contributions to our pension and other post-employment benefit plans.

We provide a defined benefit pension plan and other post-retirement benefits for a substantial number of employees, former employees and retirees. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors beyond our control. These factors include estimated investment returns, interest rates, discount rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In 2008 and 2009, due to the financial crisis, the value of our pension assets declined. As a result, we made a contribution of approximately $144 million in 2011 and expect to make an approximate $197 million contribution in 2012. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional large funding requirements, when combined with the financing requirements of our construction program, could impact the timing and amount of future equity and debt financings and negatively affect our financial position, results of operations or cash flows.

Costs of compliance with environmental regulations, including climate change legislation, 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 that govern, 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 our financial position, results of operations or cash flows.

In addition, global climate change issues have received an increased focus from federal and state governments, 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 customers, their impact on energy use by customers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time. The impact of these additional costs to customers could lead to a further reduction in energy consumption resulting in a decline in electricity and gas sales in our service territories, which would have an adverse impact on our business and financial position, results of operations or cash flows.

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. The cost impact of any such laws, rules or regulations 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*, included in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent's liquidity is dependent on dividends from its subsidiaries, primarily the Regulated companies, its bank facility, and its ability to access the long-term debt and equity capital markets.

NU parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its debt service obligations and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or to repay borrowings from NU parent; and/or NU parent's ability to access its credit facility or the long-term debt and equity capital markets. Prior to funding NU parent, the Regulated companies have financial obligations that must be satisfied, including among others, their operating expenses, debt service, preferred dividends (in the case of CL&P) and obligations to trade creditors. Additionally, the Regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the Regulated companies not be able to pay dividends to or repay funds due to NU parent or if NU parent cannot access its bank facilities or the long-term debt and equity capital markets, NU parent's ability to pay interest, dividends and its own debt obligations would be restricted.

Risks Related to the Pending Merger with NSTAR

We may be unable to obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions which may make it undesirable to complete the merger.

The merger is subject to numerous conditions, including the approval of PURA and the DPU, which may not approve the merger, or such approvals may impose conditions on the completion, or require changes to the terms of the merger, including restrictions on the business, operations or financial performance of the combined company, which could be adverse to the company's interests. These conditions or changes could also delay or increase the cost of the merger or limit the net income or financial prospects of the combined company.

We will be subject to business uncertainties and contractual restrictions while the merger is pending.

The work required to complete the merger may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the merger instead of on day-to-day management activities, including pursuing other opportunities beneficial to NU. In addition, while the merger is pending our business operations are restricted by the merger agreement to ordinary course of business activities consistent with past practice, which may cause us to forgo otherwise beneficial business opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees.

Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results, and we could face litigation concerning the merger, whether or not the merger is consummated.

Failure to complete the merger could negatively affect our share price, as well as our future business and financial results. If the merger is not completed for certain reasons specified in the merger agreement, we may be required to pay NSTAR a termination fee of $135 million plus up to $35 million of certain expenses incurred by NSTAR. In addition, we must pay our own costs related to the merger including, among others, legal, accounting, advisory, financing and filing fees and printing costs, whether the merger is completed or not. Further, whether or not the merger is completed, we could be subject to litigation related to the failure to complete the merger or other factors, which may adversely affect our business, financial results and share price.

If completed, the merger may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits. If the merger is completed, our ability to achieve the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Item 1B.
Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2.
Properties

Transmission and Distribution System

As of December 31, 2011, our electric operating subsidiaries owned 32 transmission and 404 distribution substations that had an aggregate transformer capacity of 6,584,000 kilovolt amperes (kVa) and 26,839,000 kVa, respectively; 2,969 circuit miles of overhead transmission lines ranging from 69 KV to 345 KV, and 433 cable miles of underground transmission lines ranging from 69 KV to 345 KV; 34,972 pole miles of overhead and 4,000 conduit bank miles of underground distribution lines; and 551,338 underground and overhead line transformers in service with an aggregate capacity of 38,721,890 kVa.

EXHIBIT 2

NORTHEAST UTILITIES

10-K

Annual report pursuant to section 13 and 15(d)
Filed on 2/25/2011
Filed Period 12/31/2010

Northeast Utilities

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, 2010

OR

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

For the transition period from ____________ to ____________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
0-00404	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) 107 Selden Street Berlin, Connecticut 06037-1616 Telephone: (860) 665-5000	06-0303850
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) Energy Park 780 North Commercial Street Manchester, New Hampshire 03101-1134 Telephone: (603) 669-4000	02-0181050
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-1961130

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.

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, 2010) was **$4,486,982,187** based on a closing sales price of **$25.48** per share for the 176,098,202 common shares outstanding on June 30, 2010. **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 as of January 31, 2011
Northeast Utilities Common shares, $5.00 par value	176,504,390 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 March 30, 2011	Part III

GLOSSARY OF TERMS

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

CURRENT OR FORMER NU COMPANIES, SEGMENTS OR INVESTMENTS:

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

REGULATORS:

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

OTHER:

2010 Healthcare Act	Patient Protection and Affordable Care Act
2010 Tax Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act
AFUDC	Allowance For Funds Used During Construction
AMI	Advanced metering infrastructure
ARO	Asset Retirement Obligation
C&LM	Conservation and Load Management
CAAA	Clean Air Act Amendments
CERCLA	The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
CfD	Contract for Differences
CO_2	Carbon dioxide
CSC	Connecticut Siting Council
CTA	Competitive Transition Assessment
CWIP	Construction work in progress
CYAPC	Connecticut Yankee Atomic Power Company
EFSB	Massachusetts Energy Facilities Siting Board
EIA	Energy Independence Act
EMF	Electric and Magnetic Fields

EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ES	Default Energy Service
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse Gas
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Giga-watt Hours
HG&E	Holyoke Gas and Electric, a municipal department of the town of Holyoke, MA
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High voltage direct current
Hydro Renewable Energy	H.Q. Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE	ISO New England, Inc., the New England Independent System Operator
KV	Kilovolt
KWh	Kilowatt-Hours
LNG	Liquefied natural gas
LOC	Letter of Credit
LRS	Last resort service
MGP	Manufactured Gas Plant
Millstone	Millstone Nuclear Generating station, made up of Millstone 1, Millstone 2, and Millstone 3. All three units were sold in March 2001.
MMBtu	One million British thermal units
Money Pool	Northeast Utilities Money Pool
Moody's	Moody's Investors Services, Inc.
MW	Megawatt
MWh	Megawatt-Hours
MYAPC	Maine Yankee Atomic Power Company
NEEWS	New England East-West Solution
NO_x	Nitrogen oxide
Northern Pass	The high voltage direct current transmission line project from Canada into New Hampshire
NPDES	National Pollutant Discharge Elimination System
NU supplemental benefit trust	The NU Trust Under Supplemental Executive Retirement Plan
NWPP	Northern Wood Power Project
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan that provides certain retiree health care benefits, primarily medical and dental, and life insurance benefits
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PGA	Purchased Gas Adjustment
PPA	Pension Protection Act
RECs	Renewable Energy Certificates
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
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RNS	Regional Network Service
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
RTO	Regional Transmission Organization
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide

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

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

2010 Form 10−K Annual Report
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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 contracts
- actions of rating agencies
- The expected timing and likelihood of completion of the proposed merger with NSTAR, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, as well as the ability to successfully integrate the businesses, and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect and
- other presently unknown or unforeseen factors.

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

All such factors are difficult to predict, contain uncertainties that may materially affect our actual results and are beyond our control. You should not place undue reliance on the forward-looking statements, each speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see Item 1A, *Risk Factors,* included in this 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.

PART I

Item 1.
Business

Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this Annual Report on Form 10-K.

PROPOSED MERGER WITH NSTAR

On October 18, 2010, we and NSTAR announced that each company's Board of Trustees unanimously approved a Merger Agreement (the merger agreement) to combine the two companies. The transaction was structured as a merger of equals in a tax-free exchange. Upon the terms and subject to the conditions set forth in the merger agreement, at closing, NSTAR will become a wholly-owned subsidiary of NU. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England.

Under the terms of the merger agreement, NSTAR shareholders would receive 1.312 NU common shares for each common share of NSTAR that they own (the "exchange ratio"). The exchange ratio was structured to result in a no premium merger and is based on the average closing share price of each company's common shares for the 20 trading days preceding the announcement. Following completion of the merger, common shares of the post-transaction company will be owned approximately 56 percent by NU shareholders and approximately 44 percent by former NSTAR shareholders. We anticipate that we will issue approximately 137 million common shares to the NSTAR shareholders as a result of the merger. Following the closing of the merger, our next quarterly dividend per common share will be increased to an amount that is equivalent to NSTAR's last quarterly dividend per common share paid prior to the closing, divided by the exchange ratio. Based on the last quarterly dividend paid by NSTAR of $0.425 per share, and assuming there are no changes to such dividend prior to the closing of the merger, that would result in NU's quarterly dividend being increased by approximately 18 percent to approximately $0.325 per share, or approximately $1.30 per share on an annualized basis as compared to NU's current annualized dividend of $1.10 per share. NU filed its joint proxy statement/prospectus with the SEC on January 5, 2011 and scheduled a special meeting of shareholders for March 4, 2011, at which shareholders will vote on whether to approve the merger.

Completion of the merger is subject to various customary conditions, including approval by holders of two-thirds of the outstanding common shares of each company and receipt of all required regulatory approvals, including those of the Massachusetts DPU, the FERC and the NRC. We received approval from the FCC on January 4, 2011, and on February 10, 2011, the applicable Hart-Scott-Rodino waiting period expired. Several intervening parties have applied to participate in the regulatory review of the merger and have raised various issues that they believe the regulatory agencies should examine in the course of the proceedings.

In November 2010, the DPUC issued a draft decision stating it lacked jurisdiction over the merger. In December 2010, the Connecticut Office of Consumer Counsel, supported by the Connecticut Attorney General, petitioned the DPUC to reconsider its draft decision. In January 2011, the DPUC issued an Administrative Order stating that it plans to hold a hearing to determine if it has jurisdiction over the merger. Oral arguments surrounding the draft decision were held in February 2011. The DPUC plans to hold an informational hearing at a date to be determined. In addition, legislation proposing to give the DPUC jurisdiction over the merger may be introduced in the Connecticut legislature.

THE COMPANY

NU, headquartered in Hartford, Connecticut, is a public utility holding company subject to regulation by FERC under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned utility subsidiaries:

- The Connecticut Light and Power Company (CL&P), a regulated electric utility that serves residential, commercial and industrial customers in parts of Connecticut;
- Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire and continues to own generation assets used to serve customers;
- Western Massachusetts Electric Company (WMECO), a regulated electric utility that serves residential, commercial and industrial customers in parts of western Massachusetts; and
- Yankee Gas Services Company (Yankee Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut.

NU also owns certain unregulated businesses through its wholly-owned subsidiary, NU Enterprises. As of December 31, 2010, NU Enterprises' business consisted of (i) Select Energy's few remaining energy wholesale marketing contracts, which are being wound down, and (ii) NU Enterprises' electrical contracting business.

Although NU, CL&P, PSNH and WMECO each report their financial results separately, we also include information in this report on a segment, or line–of–business, basis – the distribution segment (which also includes the generation businesses of PSNH and WMECO and our natural gas distribution business) and the transmission segment. Our Regulated companies accounted for approximately 99 percent of our total earnings of $387.9 million for 2010, with electric distribution representing approximately 45 percent, natural gas distribution representing approximately 8 percent and electric transmission representing approximately 46 percent of consolidated earnings. The remaining 1 percent of our 2010 earnings comes from our competitive businesses.

REGULATED ELECTRIC DISTRIBUTION

General

NU's electric distribution segment consists 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 and WMECO's solar generation. The following table shows the sources of 2010 electric franchise retail revenues for NU's electric distribution companies, collectively, based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	59%
Commercial	33%
Industrial	7%
Other	1%
Total	100%

A summary of changes in the Regulated companies' retail electric sales (GWh) for 2010 as compared to 2009 on an actual and weather normalized basis (using a 30–year average) is as follows:

	2010	2009	Percentage Increase/ (Decrease)	Weather Normalized Percentage (Decrease)
Residential	14,913	14,412	3.5%	(0.7)%
Commercial	14,506	14,474	0.2%	(2.8)%
Industrial	4,481	4,423	1.3%	(1.5)%
Other	330	336	(1.4)%	(1.4)%
Total	34,230	33,645	1.7%	(1.7)%

Total retail electric sales for all three electric companies were higher in 2010 compared to 2009 due primarily to warmer than normal weather in the summer of 2010 and colder than normal weather in December 2010. Residential sales benefitted the most from the weather in 2010 and were higher for all three electric companies in 2010 compared to 2009.

On a weather normalized basis, retail sales for all three electric companies were lower in 2010 compared to 2009. We believe the decrease was due in part to increased conservation efforts by our customers and the continuing effects of the weak economy.

THE CONNECTICUT LIGHT AND POWER COMPANY – DISTRIBUTION

CL&P's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2010, 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. In 2010, CL&P had contracts to purchase the electric output from eighteen IPP generators. The term of two of these contracts ended in 2010. In 2011 the sixteen remaining generators are anticipated to provide approximately two million MWh per year through March 2015, with purchase quantities dropping significantly from 2015 through 2024, when the term of the last IPP contract ends. CL&P sells the output of these contracts into the ISO New England market, crediting customer energy charges with the proceeds. CL&P has entered into eleven contracts with renewable energy generators under a state program known as Project 150, and UI has entered into 2 other similar contracts under Project 150. CL&P and UI will share the costs and benefits of these contracts on an 80 percent and 20 percent basis, respectively. This cost sharing split is independent of the specific utility that is the counterparty to the contract. It is currently projected that the first of these renewable energy projects will commence commercial operation in 2011.

The following table shows the sources of 2010 electric franchise retail revenues for CL&P based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	61%
Commercial	32%
Industrial	6%
Other	1%
Total	100%

Rates

CL&P is subject to regulation by the Connecticut DPUC, which, among other things, has jurisdiction over its 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, CTA, SBC and other charges that are assessed on all customers.

The CTA is a charge assessed to recover stranded costs associated with electric industry restructuring as well as various IPP contracts. The SBC recovers costs associated with various hardship and low income programs as well as payments to municipalities to compensate them for losses in property tax revenue due to decreases in the value of electric generating facilities resulting directly from electric industry restructuring. The CTA and SBC are annually reconciled to actual costs incurred, with any difference refunded to, or recovered from, customers.

Under state law, all of CL&P's customers are entitled to choose their energy suppliers, while CL&P remains 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 the cost to such customers through a combined GSC and FMCC on customers' bills. The combined GSC and FMCC charges for both types of service recover all of the costs of procuring energy from CL&P's wholesale suppliers and are adjusted periodically and reconciled semi-annually in accordance with the directives of the DPUC.

Although more CL&P customers chose competitive energy suppliers in 2010 than in 2009, CL&P continues to supply approximately 40 percent of its customer load at Standard Service or Supplier of Last Resort Service rates while the other 60 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on CL&P's delivery business or its operating income.

Distribution Rates: On June 30, 2010, the DPUC issued a final order in CL&P's most recent retail rate case approving annualized distribution rate increases of $63.4 million effective July 1, 2010 and an incremental $38.5 million effective July 1, 2011. The 2010 increase was deferred from customer bills until January 1, 2011 to coincide with the decline in revenue requirements associated with the final payment of CL&P's RRBs. In its decision, the DPUC also maintained CL&P's authorized distribution segment regulatory ROE of 9.4 percent. In 2010, CL&P earned a distribution segment regulatory ROE of 7.9 percent, compared to 7.3 percent in 2009, and expects to earn a distribution segment regulatory ROE of approximately 9 percent in 2011.

In May 2010, the Connecticut Legislature approved a state budget for the 2010-2011 fiscal year, which calls for the issuance by the state of Connecticut of up to $760 million of economic recovery revenue bonds (ERRBs) that would be amortized over eight years. These bonds will be repaid through a charge on the bills of customers of CL&P and other Connecticut electric distribution companies. For CL&P, the revenue to pay interest and principal on the bonds would come from a continuation of a portion of its CTA, which would have otherwise ended by December 31, 2010 with the final payment of the principal and interest on its RRBs, and the diversion of about one-third of the annual funding for C&LM programs beginning in April 2012. A lawsuit pending against the DPUC to prevent the issuance of the ERRBs is pending and several bills seeking to modify or prevent the issuance have been proposed before the state legislature.

On March 31, 2010, CL&P filed with the DPUC an AMI and dynamic pricing plan concluding that a full deployment of AMI meters accompanied by dynamic pricing options for all CL&P customers would be cost beneficial under a set of reasonable assumptions, identified as the "base case scenario." Under the base case scenario, capital expenditures associated with the installation of the meters are estimated at $296 million. CL&P has proposed beginning installation of meters in late 2012 and finishing in 2016.

CL&P has a transmission adjustment clause as part of its retail distribution rates, which reconciles on a semi-annual basis the transmission revenues billed to customers against the transmission costs of acquiring such services, thereby recovering all of its transmission expenses on a timely basis.

Sources and Availability of Electric Power Supply

As noted above, CL&P does not own any generation assets and purchases energy to serve its Standard Service and Supplier of Last Resort Service loads from a variety of competitive sources through periodic RFPs. CL&P enters into supply contracts for Standard Service periodically for periods of up to three years to mitigate price volatility for its residential and small and medium load commercial and industrial customers. CL&P enters into supply contracts for Supplier of Last Resort service for larger commercial and industrial customers every three months. Currently, CL&P has contracts in place with various suppliers for all of its Standard Service loads through 2011, 40 percent of expected load for 2012, and 10 percent of expected load for 2013. CL&P's contracts for its Supplier of Last Resort Service loads extend through the second quarter of 2011.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE - DISTRIBUTION

PSNH's distribution business (which includes its generation business) consists primarily of the generation, purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2010, PSNH furnished retail franchise electric service to approximately 497,000 retail customers in 211 cities and towns in New Hampshire. PSNH also owns and operates approximately 1,200 MW of primarily fossil-fueled electricity generation assets. Included in those generation assets is its 50 MW wood-burning Northern Wood Power Project at its Schiller Station in Portsmouth, New Hampshire, and approximately 70 MW of hydroelectric generation. PSNH also has contracts with 18 IPPs, the output of which it either uses to serve its customer load or sells into the market.

PSNH is constructing its Clean Air Project, a sulfur dioxide and mercury scrubber at its Merrimack coal-fired generation station, which is currently expected to cost $430 million. The project is scheduled for completion in mid-2012. PSNH will recover all related costs through its ES rates described below.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	54%
Commercial	36%
Industrial	9%
Other	1%
Total	100%

Rates

PSNH is subject to regulation by the 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 ES rate recovers its generation and purchased power costs from customers on a current basis and allows for an ROE of 9.81 percent on its generation investment.

Under New Hampshire law, the SCRC allows PSNH to recover its stranded costs, including expenses incurred under 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 and recovers the costs of these bonds through the SCRC rate.

On an annual basis, PSNH files with the NHPUC an ES/SCRC reconciliation filing for the preceding year. The difference between ES/SCRC revenues and ES/SCRC costs are included in the ES/SCRC rate calculations and refunded to/recovered from customers in the subsequent period approved by the NHPUC.

The TCAM allows PSNH to recover on a fully reconciling basis its transmission related costs. The TCAM is adjusted July 1 of each year.

Distribution Rates: On June 28, 2010, the NHPUC approved a joint settlement of PSNH's rate case that had commenced in 2009, allowing a net distribution rate increase of $45.5 million on an annualized basis to be effective July 1, 2010, and annualized distribution rate adjustments projected to be a decrease of $2.9 million and increases of $9.5 million and $11.1 million on July 1 of each of the three subsequent years, respectively. PSNH agreed not to file a new distribution rate request that would be effective prior to July 1, 2015. During the term of the settlement, PSNH can only propose changes to its permanent distribution rate level when its 12-month distribution ROE falls below 7 percent for two consecutive quarters or certain specified external events, such as major storms, occur. If PSNH's 12-month ROE rolling average is greater than 10 percent, anything over the 10 percent level will be allocated 75 percent to customers and 25 percent to PSNH. The settlement also provided that the authorized regulatory ROE on distribution only plant will continue at the previously allowed level of 9.67 percent. PSNH's distribution segment regulatory ROE was 10.2 percent (including generation) in 2010, compared to 7.2 percent in 2009. We expect PSNH's distribution segment regulatory ROE will be approximately 9 percent in 2011.

PSNH's customers are entitled to choose competitive energy suppliers, with PSNH providing default energy service under its ES rate for those customers who do not elect to use a third party supplier. Prior to 2009, PSNH experienced only a minimal amount of customer migration. However, customer migration levels began to increase significantly in 2009 as energy costs decreased from their historic high levels and competitive energy suppliers with more pricing flexibility were able to offer electricity supply at lower prices than PSNH. By the end of 2010, approximately 2 percent of all of PSNH's customers (approximately 32 percent of load), mostly large commercial and industrial customers, had switched to competitive energy suppliers. The increased level of migration has caused an increase in the ES rate, as fixed costs of PSNH's generation assets must be spread over a smaller group of customers and lower sales volume. The customers that did not switch to a third party supplier, predominately residential and small commercial and industrial customers, are now paying a larger proportion of these fixed costs.

The NHPUC opened a proceeding in 2010 to consider the effect of customer migration on ES rates for customers, principally residential and small commercial and industrial customers, remaining on PSNH default energy service. As part of this docket, the NHPUC stated its intention to explore the interplay of customer choice, migration issues and power procurement options for PSNH.

PSNH cannot predict if the upward pressure on ES rates will continue into the future, as future customer migration levels, which are dependent on market prices and supplier alternatives, are uncertain. If future market prices once more exceed the average ES rate level, some or all of these customers on third party supply may migrate back to PSNH.

Sources and Availability of Electric Power Supply

During 2010, about 88 percent of PSNH's load was met through its own generation, long-term power supply provided pursuant to orders of the NHPUC, and contracts with third parties. The remaining 12 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 2011 in a similar manner.

WESTERN MASSACHUSETTS ELECTRIC COMPANY - DISTRIBUTION

WMECO's distribution business consists primarily of the purchase, delivery and sale of electricity to residential, commercial and industrial customers. At December 31, 2010, WMECO furnished retail franchise electric service to approximately 206,000 retail customers in 59 cities and towns in the western third of Massachusetts. Following electric industry restructuring in the 1990s, WMECO sold all of its generating facilities and now purchases its energy requirements from competitive suppliers. In 2009, pursuant to the Massachusetts Green Communities Act, WMECO was authorized to install 6 MW of solar energy generation in its service territory. In October 2010, WMECO completed construction of a 1.8 MW solar generation facility at a site in Pittsfield, Massachusetts, which began producing electricity in late 2010. In January 2011, WMECO announced its plans to develop a second solar generation facility at a site in Springfield, Massachusetts. This facility will accommodate 17,000 solar panels, producing up to 4.2 MW of solar energy. WMECO will sell all energy and other products from its solar generation facilities into the ISO New England market. WMECO had a contract with one IPP generator in 2010, the output of which WMECO sold into the ISO New England market. The term of this contract ended on December 31, 2010.

The following table shows the sources of 2010 electric franchise retail revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	57%
Commercial	33%
Industrial	9%
Other	1%
Total	100%

Rates

WMECO is subject to regulation by the Massachusetts 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, acquisition of 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 recover their reasonable operation and capital costs, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests.

Under state law, WMECO's customers are entitled to choose their energy suppliers, while WMECO remains their distribution company. WMECO purchases electric power from competitive suppliers 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 small commercial and industrial customers have continued to buy their power from WMECO at basic service rates. A greater proportion of large commercial and industrial customers have opted for a competitive energy supplier.

WMECO continues to supply approximately 50 percent of its customer load at basic service rates while the other 50 percent of its customer load has migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on WMECO's delivery business or its operating income.

WMECO recovers certain costs through various tracking mechanisms in its retail rates, including transmission costs, pension costs and prudently incurred stranded costs (a portion of which have been financed through securitization by issuing RRBs) with periodic true-up adjustments.

Distribution Rates: On January 31, 2011, the DPU issued a final decision in WMECO's July 2010 rate application, granting a $16.8 million annualized rate increase in distribution revenues and an allowed ROE of 9.6 percent effective February 1, 2011. The DPU also authorized a full decoupling mechanism, whereby actual revenue billed by WMECO would be reconciled with WMECO's target revenue on an annual basis, WMECO's request to recover balances of certain active hardship account balances and the recovery of certain storm costs over five years. The DPU did not authorize rate recovery of a proposed $20 million average increase in WMECO's capital spending plan. WMECO's distribution segment regulatory ROE was 4.6 percent in 2010 compared to 8.4 percent in 2009. We expect WMECO's distribution segment regulatory ROE will be approximately 9 percent in 2011.

WMECO is subject to SQ metrics that measure safety, reliability and customer service, and WMECO pays any charges incurred for failure to meet such metrics to customers. WMECO will not be required to pay an assessment charge for its 2010 performance results as WMECO performed at target for all of its SQ metrics in 2010.

On October 16, 2009, WMECO filed its proposal for a dynamic pricing smart meter pilot program with the DPU. However, the Company does not expect it will conduct a pilot prior to 2012.

Sources and Availability of Electric Power Supply

As noted above, WMECO does not own any generation assets (other than its recently constructed solar generation) 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.

REGULATED GAS DISTRIBUTION – YANKEE GAS SERVICES COMPANY

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers (approximately 206,000 customers in 71 cities and towns), and size of service territory (2,187 square miles). Total throughput (sales and transportation) in both 2010 and 2009 was approximately 52.5 Bcf. Yankee Gas provides firm natural gas sales service to retail customers who require a continuous natural 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 natural gas from Yankee Gas. Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas' service territory buy gas supply and delivery only from Yankee Gas while commercial and industrial customers have choice in their gas suppliers. Yankee Gas 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 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. Yankee Gas also owns a 1.2 Bcf LNG facility in Waterbury, Connecticut, which enables the company to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher.

The following table shows the sources of 2010 gas operating revenues based on categories of customers:

Sources of Revenue	% of Total Revenues
Residential	51%
Commercial	30%
Industrial	16%
Other	3%
Total	100%

A summary of firm natural gas sales in million cubic feet for Yankee Gas for 2010 and 2009 and the percentage changes in 2010 as compared to 2009 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Firm Natural Gas Sales (Mcf)			
	2010	2009	Percent Decrease/ Increase	Weather Normalized Percentage (Decrease)
Residential	13,403	13,562	(1.2)%	4.9%
Commercial	14,982	14,063	6.6%	12.1%
Industrial	14,866	14,825	0.3%	1.7%
Total	43,251	42,450	1.9%	6.2%

Yankee Gas' firm natural gas sales are subject to many of the same influences as our retail electric sales, but they have recently benefitted from a favorable price for natural gas relative to competing fuels resulting in commercial and industrial customers switching from interruptible service to firm service, and the addition of gas-fired distributed generation in Yankee Gas' service territory. Actual firm natural gas sales in 2010 were higher than 2009 despite the milder weather during the first quarter 2010 heating season. Firm natural gas sales benefitted from these trends and from a large commercial customer who began to take service from Yankee Gas mid-way through the third quarter of 2009 and continued to take service throughout all of 2010.

In April 2010, Yankee Gas commenced construction of its WWL project, a 16-mile gas pipeline between Waterbury and Wallingford, Connecticut coupled with the increase of vaporization output of its LNG plant. The project is expected to cost approximately $57.6 million. In 2010, approximately $26.6 million was spent on construction of the WWL project, which included construction of a segment of pipeline connecting the Cheshire and Wallingford distribution systems. The remainder of the pipeline construction and the expansion of the vaporization capacity of the LNG facility are expected to be completed in the fourth quarter of 2011

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.

Distribution Rates: On January 7, 2011, Yankee Gas filed an application with the DPUC to raise natural gas distribution rates by $32.8 million, or 7.3 percent, to be effective July 1, 2011, and by an additional $13 million, or 2.8 percent, to be effective July 1, 2012. Among other items, Yankee Gas requested to maintain its current authorized ROE of 10.1 percent, that $57.6 million of costs associated with the WWL project be placed into rates, and that a substantial increase in capital funding to replace bare steel and cast iron pipe on Yankee Gas' system. A final decision is expected in June 2011. Yankee Gas' regulatory ROE was 8.6 percent in 2010 compared to 6.6 percent in 2009. We expect Yankee Gas' distribution segment regulatory ROE to be approximately 9 percent in 2011.

Sources and Availability of Natural Gas Supply

The DPUC requires that Yankee Gas meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its portfolio to meet firm customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas' LNG facility enables Yankee Gas to buy natural gas in periods of low demand, store it and use it during peak demand periods when prices are typically higher. Yankee Gas' on-system stored LNG and underground storage supplies help to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate capacity from the three interstate pipelines that currently directly serve Connecticut: the Algonquin, Tennessee and Iroquois Pipelines. Yankee Gas has long-term firm contracts for capacity on TransCanada Pipelines Limited pipeline, Vector Pipeline, L.P., Tennessee Gas Pipeline, Iroquois Gas Transmission Pipeline, Algonquin Pipeline, Union Gas Limited, Dominion Transmission, Inc., National Fuel Gas Supply Corporation, Transcontinental Gas Pipeline Company, and Texas Eastern Transmission, L.P. pipelines. Yankee Gas considers such transportation arrangements adequate for its needs.

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 of all market participants, has served since 2005 as the RTO of the New England transmission system. ISO-NE works to ensure the reliability of the system, administers, subject to FERC approval, the independent system operator tariff, oversees the efficient and competitive functioning of the regional wholesale power market and determines which costs of all regional major transmission facilities are shared by consumers throughout New England.

Wholesale Transmission Rates

Wholesale transmission revenues are recovered through formula rates that are approved by the FERC. Our transmission revenues are recovered from New England customers through ISO-NE charges which recover costs of transmission and other transmission-related services provided by all regional transmission owners, with a portion of those revenues collected from the distribution segments of CL&P, PSNH and WMECO.

FERC ROE Decision

Pursuant to a series of orders involving the ROE for regionally planned New England transmission projects, the FERC set the base ROE at 11.14 percent and approved incentives that increased the ROE to 12.64 percent for those projects that were in-service by the end of 2008. In addition, certain projects were granted additional ROE incentives by FERC under its transmission incentive policy. As a result, CL&P earns between 12.64 percent and 13.1 percent on its major transmission projects. All appeals of FERC's orders on the ROE for New England transmission owners have been denied.

On November 17, 2008, the FERC issued an order granting certain incentives and rate amendments to National Grid and us for certain components of the proposed NEEWS project, which is described below. The approved incentives include (1) an ROE of 12.89 percent; (2) inclusion of 100 percent CWIP costs in rate base; and (3) full recovery of prudently incurred costs if any portion of NEEWS is abandoned for reasons beyond our control. Several parties have sought rehearing of this FERC order on which FERC has not yet acted.

Transmission Projects

NEEWS

CL&P and WMECO are continuing to develop and build the NEEWS project, which is comprised of GSRP, the Interstate Reliability Project and the Central Connecticut Reliability Project, and is estimated to cost $1.52 billion in the aggregate (approximately $1.45 billion reflecting the impact of UI's potential investment of up to approximately $69 million as discussed below). CL&P and WMECO commenced substation construction on GSRP in December 2010 and expect to begin overhead line construction in the first half of 2011. We expect GSRP to be placed in service in late 2013 at a cost of approximately $795 million.

CL&P is designing and building the Interstate Reliability Project in coordination with National Grid USA, whose segment of this phase will interconnect with CL&P's at the Connecticut-Rhode Island border. In August 2010, ISO-NE reaffirmed the need for the Interstate Reliability Project. We expect CL&P's share of the costs of this project to be $301 million and that the project will be placed in service in late 2015.

The timing of the Central Connecticut Reliability Project is expected to be twelve months behind the Interstate Reliability Project and cost approximately $338 million. ISO-NE continues to assess the need date for the Central Connecticut Reliability Project and we expect that ISO-NE will conclude its evaluation by mid-2011.

Included as part of NEEWS are $84 million of expenditures for associated reliability related projects, all of which have received siting approval and most are under construction. The in-service dates for these projects range from later this year through 2013.

Northern Pass Transmission Line Project

NPT is a limited liability company jointly formed by NU and NSTAR to construct, own and operate the Northern Pass transmission line, a new HVDC transmission line from the border of Canada and the United States to Franklin, New Hampshire that will interconnect at the border with a new HVDC transmission line being developed by HQ TransEnergie, the transmission subsidiary of HQ. NUTV, a subsidiary of NU, holds a 75 percent interest in NPT, with NSTAR Transmission Ventures, Inc., a subsidiary of NSTAR, holding the remaining 25 percent. Consistent with FERC's February 11, 2011 order accepting the TSA between NPT and Hydro Renewable Energy that was filed December 15, 2011, NPT will charge Hydro Renewable Energy cost-based rates for firm transmission service over the Northern Pass line for a 40-year term. The projected cost-of-service calculation includes an ROE of 12.56 percent through the construction phase of the project. Upon commercial operation, the ROE will be equal to the ISO-NE regional rates base ROE (currently 11.14 percent) plus 1.42 percent based on a deemed capital structure for NPT of 50 percent debt and 50 percent equity.

In October 2010, NPT filed the Northern Pass project design with ISO-NE for technical approval and filed a presidential permit application with the DOE. The DOE application seeks permission for NPT to construct and maintain facilities that cross the U.S. border and connect to HQ TransEnergie's facilities in Canada. Assuming timely regulatory review and siting approvals, NPT expects to commence construction of the Northern Pass in 2013, with power flowing across the line in late 2015.

We currently estimate that our 75 percent share of the costs to build the Northern Pass transmission project will be approximately $830 million out of total expected costs of approximately $1.1 billion (including capitalized AFUDC).

Other Transmission Transactions

In July 2010, CL&P and UI entered into an agreement under which UI would acquire certain transmission assets within CL&P's portion of each of the NEEWS segments. Under the terms of the agreement, which has received approval from the FERC and the DPUC, UI will have the option to invest up to $69 million or an amount equal to 8.4 percent of CL&P's costs for the assets, which are expected to aggregate approximately $828 million.

On December 17, 2010, CL&P and CTMEEC, a non-profit municipal joint action transmission entity formed by several Connecticut municipal electric companies, entered into an agreement , subject to DPUC approval, under which CTMEEC would acquire a segment of CL&P's high voltage transmission lines in the town of Wallingford, Connecticut. The transaction was approved by FERC on January 31, 2011. The purchase price will be based on the net book value of the assets at the time of the closing of the sale in May 2011, projected to be approximately $42.3 million. CL&P will continue to operate and maintain the lines for CTMEEC.

Transmission Rate Base

Under our FERC-approved tariff, transmission projects generally enter rate base once they are placed in commercial operation. However, 100 percent of the NEEWS projects will enter rate base during their construction period. At the end of 2010, our transmission rate base was approximately $2.8 billion, including approximately $2.1 billion at CL&P, $341 million at PSNH and $269 million at WMECO. We forecast that our total transmission rate base will grow to approximately $4.8 billion by the end of 2015, including approximately $830 million at NPT.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The principal focus of our construction and capital improvement program is maintaining, upgrading and expanding our existing electric generation, transmission and distribution systems and our natural gas distribution system. Our consolidated capital expenditures in 2010 totaled approximately $1 billion, almost all of which ($967 million) was expended by the Regulated companies. The capital expenditures of these companies in 2011 are estimated to total approximately $1.2 billion, $477 million by CL&P, $284 million by PSNH, $287 million by WMECO and $113 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 we expect to become committed projects in 2011.

In 2010, CL&P's transmission capital expenditures totaled approximately $107 million, and its distribution capital expenditures totaled approximately $305 million. For 2011, CL&P projects transmission capital expenditures of approximately $137 million and distribution capital expenditures of approximately $337 million. During the period 2011 through 2015, CL&P plans to invest approximately $1 billion in transmission projects, the majority of which will be for NEEWS and $1.9 billon on distribution projects. 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 $2.1 billion at the end of 2010 to approximately $2.6 billion by the end of 2015, and its rate base for distribution assets is projected to increase from approximately $2.3 billion to approximately $3.3 billion over the same period.

In 2010, PSNH's transmission capital expenditures totaled approximately $49 million, its distribution capital expenditures totaled approximately $84 million and its generation capital expenditures totaled $177 million. For 2011, PSNH projects transmission capital expenditures of approximately $59 million, distribution capital expenditures of approximately $113 million and generation capital expenditures of approximately $112 million. The bulk of the generation capital expenditures is for the Clean Air Project. During the period 2011 through 2015, PSNH plans to spend approximately $293 million on transmission projects, approximately $621 million on distribution projects, and $274 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 $341 million at the end of 2010 to approximately $540 million by the end of 2015, and its rate base for distribution and generation assets is projected to increase from approximately $1.2 billion to approximately $1.9 billion over the same period.

In 2010, WMECO's transmission capital expenditures totaled approximately $95 million, its distribution capital expenditures totaled approximately $33.1 million and solar generation expenditures were $10 million. In 2011, WMECO projects transmission capital expenditures of approximately $229 million, distribution capital expenditures of approximately $36 million and $22 million on solar generation. During the period 2011 through 2015, WMECO plans to spend approximately $732 million on transmission projects, with the bulk of that amount to be spent on GSRP, approximately $194 million on distribution projects and $46 million on solar generation. If all of the generation, distribution and transmission projects are built as proposed, WMECO's rate base for electric transmission is projected to increase from approximately $269 million at the end of 2010 to approximately $803 million by the end of 2015 and its rate base for distribution and generation assets is projected to increase from approximately $423 million to approximately $488 million over the same period.

In 2010, Yankee Gas capital expenditures totaled approximately $95 million. For 2011, Yankee Gas projects total capital expenditures of approximately $113 million, approximately $30 million of which is expected to be related to the WWL project, $37 million related to basic business activities such as relocation of conflicting gas facilities and the purchase of meters, tools and information technology; $30 million related to reliability improvements; and $16 million for load growth and new business requests. During the period 2011 through 2015, Yankee Gas plans on making approximately $587 million of capital expenditures, including approximately $30 million on the WWL project. Future capital spending will likely be affected by price differences between the cost of natural gas with respect to home heating oil, natural gas supply, new home construction, road reconstruction, regulatory mandates and business requirements. Excluding non-recurring major projects, NU expects that approximately 28 percent of Yankee Gas' capital expenditures over the 2011-2015 period to be related to basic business activities, approximately 28 percent related to load growth and new business, and approximately 39 percent related to reliability initiatives, with the balance related to the WWL project. If all of Yankee Gas projects are built as proposed, Yankee Gas' investment in its regulated assets is projected to increase from approximately $682 million at the end of 2010 to approximately $969 million by the end of 2015.

FINANCING

NU subsidiaries issued a total of $145 million in long-term debt in 2010. On March 8, 2010, WMECO issued $95 million of senior unsecured notes due March 1, 2020 carrying a coupon rate of 5.1 percent and on April 22, 2010, Yankee Gas issued $50 million of first mortgage bonds through a private placement with a maturity date of April 1, 2020 carrying a coupon rate of 4.87 percent.

In addition, on April 1, 2010, CL&P completed the remarketing of $62 million of tax-exempt secured PCRBs. The PCRBs carry a coupon rate of 1.4 percent until April 1, 2011, at which time CL&P expects to remarket the bonds.

On September 24, 2010, NU parent entered into a three-year $500 million unsecured revolving credit facility, and CL&P, PSNH, WMECO, and Yankee Gas jointly entered into a three-year $400 million unsecured revolving credit facility, both replacing five-year credit facilities on similar terms and conditions that were scheduled to expire on November 6, 2010. Like the previous facility, NU's new revolving credit facility allows NU parent to borrow on a short-term or long-term basis, or issue LOCs, up to $500 million in the aggregate. Under their new revolving credit facility, CL&P and PSNH are each able to draw up to $300 million, with WMECO and Yankee Gas each able to draw up to $200 million, all subject to the $400 million maximum aggregate borrowing limit.

Our credit facilities and indentures require that NU parent and certain of its subsidiaries, including CL&P, PSNH, WMECO and Yankee Gas, comply with certain financial and non-financial covenants as are customarily included in such agreements, including maintaining a ratio of consolidated debt to total capitalization of no more than 65 percent. All such companies currently are, and expect to remain in compliance with these covenants.

We have annual sinking fund requirements of $4.3 million continuing in 2011 through 2012, the mandatory tender of $62 million of tax-exempt PCRBs by CL&P on April 1, 2011, at which time CL&P expects to remarket the bonds in the ordinary course. Neither NU nor any of its subsidiaries have any debt maturities until April 1, 2012.

In light of the 2010 Tax Act and the related cash flow benefits, we are currently reevaluating the timing of our previously planned NU common equity issuance. If we complete the proposed merger with NSTAR, we would no longer need to undertake the previously planned $300 million NU common equity issuance in 2012 nor issue any additional equity in the foreseeable future.

NUCLEAR DECOMMISSIONING

General

CL&P, PSNH, WMECO and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective generation 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 CL&P, PSNH and WMECO and several other New England utilities. 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
CYAPC	34.5%	5.0%	9.5%	49.0%
MYAPC	12.0%	5.0%	3.0%	20.0%
YAEC	24.5%	7.0%	7.0%	38.5%

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

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, which has jurisdiction over CL&P and Yankee Gas, the NHPUC, which has jurisdiction over PSNH, and the DPU, which has 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 approximately 1,200 MW of generation assets and expects to spend approximately $430 million on its Clean Air Project, the installation of a wet flue gas desulphurization system at its Merrimack coal station to reduce its mercury and sulfur dioxide emissions. Compliance with additional environmental laws and regulations, particularly air and water pollution control requirements may cause changes in operations or require further 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 NPDES permit from the EPA 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. In each of the last three years, the costs incurred by the Company related to compliance with NPDES and state discharge permits have not been material. The Company expects to incur additional costs related to these permits in the future; however, due to uncertainty regarding the imposition of new or additional requirements, the Company is unable to accurately estimate such costs.

Air Quality Requirements

The CAAA, as well as New Hampshire law, impose stringent requirements on emissions of SO_2 and NO_X 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 NO_X, SO_2 and CO_2 emissions 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 SO_2 emissions as well). The Clean Air Project addresses this requirement. PSNH began site work for this project in November 2008 and is scheduled to complete it by mid-2012.

In addition, Connecticut, New Hampshire and Massachusetts are each members of the RGGI, a cooperative effort by ten northeastern and mid-Atlantic states, to develop a regional program for stabilizing and reducing CO_2 emissions from fossil fuel-fired electric generating plants. Because CO_2 allowances issued by any participating state will be usable across all ten RGGI state programs, the individual state CO_2 trading programs, in the aggregate, will form one regional compliance market for CO_2 emissions. A regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year compliance period that began in 2009.

Because neither CL&P nor WMECO currently own any generating assets (other than the solar facilities owned by WMECO, which do not emit CO_2), neither is required to acquire CO_2 allowances; however, the CO_2 allowance costs borne by generators that provide energy supply to CL&P and WMECO will likely be included in wholesale rates charged to them, which costs are then recoverable from customers.

PSNH anticipates that its generating units will emit between four million and five million tons of CO_2 per year after taking into effect the operation of PSNH's Northern Wood Power Project. Under the RGGI formula, this Project 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 through 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. 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 secondary market. The cost of complying with RGGI requirements is recoverable from PSNH customers.

Each of the states in which we do business also has RPS requirements, which generally require fixed percentages of energy supply to come from renewable energy sources such as solar, hydropower, landfill gas, fuel cells and other similar sources.

New Hampshire's RPS provision requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources, beginning in 2008 at four percent and ultimately reaching 23.8 percent by 2025. In 2010, the total RPS obligation was 7.5 percent of total generation supplied to customers. Energy suppliers, like PSNH, purchase RECs from producers that generate energy from a qualifying resource and use them to satisfy the RPS requirements. PSNH also owns renewable sources and uses both internally generated RECs and purchased RECs to meet its RPS obligations. To the extent that PSNH is unable to purchase sufficient RECs, it makes up the difference between the RECs purchased and its total obligation by making an alternative compliance payment for each REC requirement for which PSNH is deficient. The costs of both the RECs and alternative compliance payments do not impact earnings, as these costs are recovered by PSNH through its ES rates charged to customers.

Connecticut's RPS statute requires electricity suppliers to meet renewable energy standards, beginning with a four percent RPS in 2004. This percentage increases each year. For 2010, the requirement was 14 percent with goals of 19.5 percent by 2015 and 27 percent by 2020. CL&P is permitted to pass any costs incurred in complying with RPS on to customers through rates.

Massachusetts' RPS program required electricity suppliers to meet a one percent renewable energy standard in 2003 and has a goal of 15 percent by 2015. For 2010, the requirement was five percent. WMECO is permitted to pass any costs incurred in complying with RPS on to customers through rates.

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, utility companies often disposed of residues from operations by depositing or burying them on-site or disposing of them at off-site landfills or other facilities. Typical materials disposed of include coal gasification byproducts, fuel oils, ash, and other materials that might contain polychlorinated biphenyls or that otherwise might be hazardous. 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. We 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 these practices. At December 31, 2010, the liability recorded by us for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was approximately $37.1 million, representing 58 sites. These costs could be significantly higher if remediation becomes 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 MGP facilities. These facilities were owned and operated by our predecessor companies 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.

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

Electric and Magnetic Fields

For more than twenty years, published reports have discussed the possibility of adverse health effects from 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.

Global Climate Change and Greenhouse Gas Emission Issues

Global climate change and greenhouse gas emission issues have received an increased focus from state governments and the federal government, particularly in recent years. The EPA has initiated a rulemaking addressing greenhouse gas emissions and, on December 7, 2009, issued a finding that concluded that greenhouse gas emissions are "air pollution" and endanger public health and welfare and should be regulated. The largest source of greenhouse gas emissions in the U.S. is the electricity generating sector. The EPA has mandated GHG emission reporting beginning in 2012 for 2011 emissions for certain aspects of our business including stationary combustion, volume of gas supplied to large customers and fugitive emissions of SF-6 gas and methane.

We are continually evaluating the risks presented by climate change concerns and issues. Such concerns could potentially lead to additional rules and regulations that impact how we operate our business, both in terms of the generating facilities we own and operate as well as general utility operations. (See "Air Quality Requirements" in this section for information concerning RGGI) These could include federal "cap and trade" laws, or regulations requiring additional capital expenditures at our generating facilities. In addition, such rules or regulations could potentially impact the prices we pay for goods and services provided by companies directly affected by such rules or regulations. We would expect that any costs of these rules and regulations would be recovered from customers, but such costs could impact energy use by our customers.

Global climate change could potentially impact weather patterns such as increasing the frequency and severity of storms or altering temperatures. These changes could affect our facilities and infrastructure and could also impact energy usage by our customers.

FERC Hydroelectric Project Licensing

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 a current claimed capability representing winter rates of approximately 71 MW, eight of which are licensed by the FERC under long-term licenses that expire on varying dates from 2017 through 2047. PSNH and its hydroelectric projects are subject to conditions set forth in such licenses, the Federal Power Act 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.

Licensed operating hydroelectric projects are not generally subject to decommissioning during the license term in the absence of a specific license provision that 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. PSNH is not presently encountering any of these challenges.

EMPLOYEES

As of December 31, 2010, we employed a total of 6,182 employees, excluding temporary employees, of which 1,847 were employed by CL&P, 1,240 by PSNH, 354 by WMECO, 429 by Yankee Gas and 2,307 were employed by NUSCO. Approximately 2,212 employees of CL&P, PSNH, WMECO, NUSCO and Yankee Gas are members of the International Brotherhood of Electrical Workers and The United Steelworkers and 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 EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), 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, 56 Prospect Street, Hartford, CT 06103.

Item 1A.
Risk Factors

In addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" included directly prior to Item 1, *Business,* above, we are subject to a variety of significant risks. 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 actions of regulators can significantly affect our earnings, liquidity and business activities.

The rates that our Regulated companies charge their respective retail and wholesale customers are determined by their state utility commissions and by FERC. These commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. FERC also regulates their transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters. The commissions' policies and regulatory actions could have a material impact on the Regulated companies' financial position, results of operations and cash flows.

Our transmission, distribution and generation systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows.

Our ability to properly operate of our transmission, distribution and generation systems is critical to the financial performance of our business. Our transmission, distribution and generation businesses face several operational risks, including the breakdown or failure of or damage to equipment or processes (especially due to age); labor disputes; disruptions in the delivery of electricity, including impacts on us or our customers; increased capital expenditure requirements, including those due to environmental regulation; information security risk, such as a breach of our systems on which sensitive utility customer data and account information are stored; catastrophic events such as fires, explosions, or other similar occurrences; and other unanticipated operations and maintenance expenses and liabilities. The failure of our transmission, distributions and generation systems to operate as planned may result in increased capital investments, reduced earnings or unplanned increases in operation and maintenance costs. At PSNH, outages at generating stations may be deemed imprudent by state regulators resulting in disallowance of replacement power costs. Such costs that are not recoverable from our customers would have an adverse effect on our financial position, results of operations and cash flows.

Limits on our access to and increases in the cost of capital may adversely impact our ability to execute our business plan.

We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. In addition, higher interest rates would increase our cost of borrowing, which could adversely impact our results of operations. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses.

Our counterparties may not meet their obligations to us.

We are exposed to the risk that counterparties to various arrangements who owe us money, or have contracted to supply us with energy, coal, or other commodities or services, or who work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of a capital project. Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected.

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

Our transmission construction plans could be affected by new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations or regulatory decisions, delays in obtaining approvals or difficulty in obtaining critical resources required for construction. Any of such events could cause delays in our construction schedule adversely affecting our ability to achieve forecasted earnings.

The regulatory approval process for our transmission projects requires extensive permitting, design and technical activities. Various factors could result in increased costs and delay construction schedules. 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 costs have been and will be prudently incurred, we cannot predict the outcome of future reviews should they occur.

In addition, our transmission projects may be delayed or displaced by new generation facilities, which could result in reduced transmission capital investments, reduced earnings, and limited future growth prospects.

Many of our transmission projects are expected to help alleviate identified reliability issues and reduce customers' costs. However, if, due to further regulatory or other delays, the in-service date for one or more of these projects is delayed, there may be increased risk of failures in the electricity transmission system and supply interruptions or blackouts, 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. 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 and/or a weak economy, can lead to changes in legislative and regulatory policy promoting energy efficiency, conservation, and self-generation and/or a reduction in our customers' ability to pay their bills, which may adversely impact our business.

Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. 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, a period of prolonged economic weakness could impact customers' ability to pay bills in a timely manner and increase customer bankruptcies, which may lead to increased bad debt expenses or other adverse effects on our financial position, results of operations or cash flows.

Connecticut, New Hampshire and Massachusetts have each investigated revenue decoupling as a mechanism to align the interests of customers and utilities relative to conservation. In Connecticut, the DPUC authorized decoupling through a rate design that is intended to recover greater distribution revenue through fixed charges, and proportionately less distribution revenue through usage-based charges. In New Hampshire, the NHPUC conducted a decoupling docket and determined that utilities were free to propose decoupling in the context of a rate case and demonstrate the effect decoupling would have on its risk profile and ROE. PSNH has not yet commenced such a proceeding. In Massachusetts, the DPU has required WMECO to adopt full decoupling in its January 31, 2011 rate decision. At this time it is uncertain what impact these decoupling mechanisms will have on our companies.

As a way to promote self-generation and reduce energy costs, Connecticut, Massachusetts, and New Hampshire have taken a greater interest in allowing customers to receive credit for generation produced at a customer-owned generating facility that exceeds their energy needs. In Massachusetts, in accordance with the Green Communities Act, the DPU adopted rules and regulations concerning net metering that will have this effect. Such rules provide a cost recovery mechanism for affected utilities to recover lost revenues. The Massachusetts DPU is expected to hold further proceedings to address net metering in early 2011. In Connecticut, the DPUC opened a docket to review existing state statutes and determine what limitations currently exist in state law concerning net metering. In addition, any legislation in Connecticut to promote self-generation and net metering could impact CL&P's financial position, results of operations or cash flows. In New Hampshire, new legislation dramatically changed the net metering rules in 2010. This new legislation is meant to encourage net metering from customers with small generators and also provides PSNH a cost recovery mechanism for lost distribution revenue.

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

The existing FERC-approved New England transmission tariff allocates the costs of transmission facilities that provide regional benefits to all customers of participating transmission-owning utilities. As new investment in regional transmission infrastructure occurs in any one state, its cost is shared across New England in accordance with relative benefits received. This regional cost allocation is set forth in the Transmission Operating Agreement signed by all of the New England transmission owning utilities. Effective February 1, 2010, this agreement can be modified with the approval of a majority of the transmission owning utilities and FERC. In addition, other parties, such as state regulators, may seek certain changes to the regional cost allocation formula, which could have adverse effects on the rates our distribution companies charge their retail customers. FERC is also considering policies to encourage the construction of transmission for renewable generation that could have the effect of imposing costs of inter-regional investment on New England customers.

Changes in regulatory or legislative policy or unfavorable outcomes in regulatory proceedings could jeopardize our full and/or timely recovery of costs incurred by our regulated distribution and generation businesses.

Under state law, our Regulated 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 such costs incurred by our Regulated companies, such as for construction, operation and maintenance, 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 costs, thereby adversely affecting our financial position, results of operations or cash flows. Additionally, state legislators may enact laws that significantly impact our Regulated companies' revenues, including by mandating electric or gas rate relief and/or by requiring surcharges to customer bills to support state programs not related to the utilities or energy policy. Such increases could pressure overall rates to our customers and our routine requests to regulators for rate relief.

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

PSNH meets most of its energy requirements through its own generation resources and fixed-price forward purchase contracts. PSNH's remaining energy needs are met primarily through spot market 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 energy to meet its 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.

Migration of customers from PSNH energy service to competitive energy suppliers could increase the cost to the remaining customers of energy produced by PSNH generation assets and decrease our revenues.

PSNH's ES rates have been higher than competitive energy prices offered to some customers in recent years, primarily due to lower natural gas prices. As a result, by the end of 2010, approximately 2 percent of PSNH's retail customers (representing approximately 32 percent of load), mostly large commercial and industrial customers, were buying their energy from competitive suppliers rather than from PSNH. The remaining retail customers are experiencing an increase in the cost of energy service supplied by PSNH by 5 percent to 7 percent due to migration of large commercial and industrial customers and the lower base in which to recover PSNH's fixed generation costs. This increase may in turn cause further migration and further increasing of PSNH energy service rates. This trend could lead to PSNH continuing to lose retail customers and increasing the burden of supporting the cost of its generation facilities on remaining customers and being unable to support the cost of its generation facilities through an ES rate.

The NHPUC is examining this issue in a proceeding in which hearings ended on December 1, 2010. PSNH has suggested transferring some fixed costs of the generation facilities into a nonbypassable charge while intervening competitive suppliers have proposed taking over the purchased power portion of the load not supplied by PSNH's generation. Others have also proposed having PSNH bid all of its generation facilities into the market while an RFP process supplies all of the power for PSNH's energy service. The NHPUC is considering further proceedings to explore these and other issues as well as the NHPUC authority to require PSNH to divest its generation facilities. It is not known what the results of such a proceeding would be, what PSNH may realize as a result of the sale or retirement of one or more of its generation facilities, or to what extent or manner the NHPUC would provide for recovery of any investment in its generation facilities.

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 is building the Clean Air Project at its Merrimack Station in Bow, New Hampshire. Several parties 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 increased costs to the project.

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 material prudence disallowance could adversely affect PSNH's financial position, results of operations or cash flows. While we believe we have prudently incurred all expenditures to date, 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 have developed 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, solar storm activity 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, including cyber-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, results of operations or cash flows.

Severe weather, such as ice and snow storms, hurricanes and other natural disasters, may cause outages and property damage, which may require us to incur additional costs 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, particularly as customers demand better and quicker response times to outages. 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.

Market performance or changes in assumptions could require us to make significant contributions to our pension and other post-employment benefit plans.

We provide a defined benefit pension plan and other post-retirement benefits for a substantial number of employees, former employees and retirees. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors beyond our control. These factors include estimated investment returns, interest rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In 2008 and 2009, due to the financial crisis, the value of our pension assets declined. As a result, we made a contribution of $45 million in 2010 and expect to make an approximate $145 million contribution in 2011. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional large funding requirements, when combined with the financing requirements of our construction program, could impact the timing and amount of future equity and debt financings and negatively affect our financial position, results of operations or cash flows.

Costs of compliance with environmental regulations, including climate change legislation, 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 that govern, 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 our financial position, results of operations or cash flows.

In addition, global climate change issues have received an increased focus from federal and state governments, 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 customers, their impact on energy use by customers and the ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time. The impact of these additional costs to customers could lead to a further reduction in energy consumption resulting in a decline in electricity and gas sales in our service territories, which would have an adverse impact on our business and financial position, results of operations or cash flows.

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. The cost impact of any such laws, rules or regulations 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," in this Annual Report on Form 10-K.

As a holding company with no revenue-generating operations, NU parent is dependent on dividends from its subsidiaries, primarily the Regulated companies, its bank facility, and its ability to access the long-term debt and equity capital markets.

NU parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its financial obligations associated with the debt service obligations on its debt and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to or to repay borrowings from NU parent; and/or NU parent's ability to access its credit facility or the long-term debt and equity capital markets. Prior to funding NU parent, the Regulated companies have financial obligations that must be satisfied, including among others, their operating expenses, debt service, preferred dividends (in the case of CL&P) and obligations to trade creditors. Additionally, the Regulated companies could retain their free cash flow to fund their capital expenditures in lieu of receiving equity contributions from NU parent. Should the Regulated companies not be able to pay dividends to or repay funds due to NU parent or if NU parent cannot access its bank facilities or the long-term debt and equity capital markets, NU parent's ability to pay interest, dividends and its own debt obligations would be restricted.

Risks Related to the Proposed Merger with NSTAR

We may be unable to satisfy the conditions or obtain the approvals required to complete the merger or such approvals may contain material restrictions or conditions.

The merger is subject to approval by the shareholders of both NU and NSTAR and numerous other conditions, including the approval of various government agencies. Governmental agencies may not approve the merger or such approvals may impose conditions on the completion, or require changes to the terms of the merger, including restrictions on the business, operations or financial performance of the combined company, which could be adverse to the company's interests. These conditions or changes could also delay or increase the cost of the merger or limit the net income or financial prospects of the combined company.

We will be subject to business uncertainties and contractual restrictions while the merger is pending.

The work required to complete the merger may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the merger instead of on day-to-day management activities, including pursuing other opportunities beneficial to NU. In addition, while the merger is pending our business operations are restricted by the Agreement and Plan of merger to ordinary course of business activities consistent with past practice, which may cause us to forgo otherwise beneficial business opportunities.

We may lose management personnel and other key employees and be unable to attract and retain such personnel and employees.

Uncertainties about the effect of the merger on management personnel and employees may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, which could affect our financial performance.

The merger may not be completed, which may have an adverse effect on our share price and future business and financial results and we could face litigation concerning the merger, whether or not the merger is consummated.

Failure to complete the merger could negatively affect NU's share price, as well as our future business and financial results. In addition, purported class actions have been brought against us, NSTAR and others on behalf of holders of NSTAR common shares. If these actions or similar actions that may be brought are successful, the costs of completing the merger could increase, or the merger could be delayed or prevented. We cannot make any assurances that we will succeed in any litigation brought in connection with the merger. See Item 3, *Legal Proceedings*, in this Annual Report on Form 10-K for discussion of pending litigation related to the merger.

If the merger is not completed for certain reasons specified in the merger agreement, we may be required to pay NSTAR a termination fee of $135 million plus up to $35 million of certain expenses incurred by NSTAR. In addition, we must pay our own costs related to the merger including, among others, legal, accounting, advisory, financing and filing fees and printing costs, whether the merger is completed or not. Further, if the merger is not completed, we could be subject to litigation related to the failure to complete the merger or other factors, which may adversely affect our business, financial results and share price.

If completed, the merger may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits. If the merger is completed, our ability to achieve the anticipated benefits will be subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Item 1B.
Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

EXHIBIT 3

Responsible Energy Action LLC

March 6, 2012

MEMORANDUM FOR THE EXECUTIVE COUNCIL

Re: Mr. Harrington Should Not be Confirmed as PUC Commissioner

Responsible Energy Action LLC ("REAL") appreciates the opportunity to provide our input to the Executive Council regarding the nomination of Mr. Michael Harrington to the position of commissioner of the Public Utilities Commission ("PUC").

A. EXECUTIVE SUMMARY

REAL respectfully requests the Executive Council to reject Mr. Harrington's nomination for three reasons.

First, we believe Mr. Harrington's flat refusal to disclose to the Executive Council the amount of his Northeast Utilities pension and other key information regarding his pension conflict shows a level of disrespect for the Executive Council, the confirmation process and the public that is inconsistent with the character, temperament and values expected of PUC commissioners.

Second, we believe Mr. Harrington's links with the regulated utility sector – including his 21+ years of prior employment at a utility and his Northeast Utilities pension (which REAL estimates may pay $400,000 to $1,750,000 to Mr. Harrington) – are too substantial to meet the public's valid expectations that PUC commissioners will be fully independent from regulated utilities both as a matter of fact and as a matter of perceptions and appearances.

Third, we believe Mr. Harrington's present, vested right to the Northeast Utilities pension clearly constitutes a disqualifying financial interest under RSA 363:5 that renders Mr. Harrington ineligible to serve as a PUC commissioner.

We estimate Mr. Harrington's Northeast Utilities pension will pay him in the range of $20,000 to $70,000 a year for life, or $400,000 to $1,750,000 in the aggregate. The total payments overwhelm in significance the $100,000 salary of a PUC commissioner and are so large as to irrevocably undercut any public confidence in Mr. Harrington's independence from the utility sector he would regulate as PUC commissioner. ***Does the Executive Council wish to risk the erosion of public confidence, increased public perceptions of a utility-captured PUC and a strong public backlash by confirming a PUC commissioner who likely stands to receive future payments of $400,000 to $1,750,000 from the utility that owns Public Service of New Hampshire ("PSNH"), the state's largest regulated electric company?***

Mr. Harrington's personal expectation of a pension payout materially depends on the financial performance of Northeast Utilities. The utility's pension plan is underfunded by almost $1 billion, and the shortfall must be made up by contributions from Northeast Utilities. Securities in the pension plan rise and fall with market movements, and Northeast Utilities's credit ultimately stands behind the pensions. ***Unless Northeast Utilities produces strong financial results in the future (which depends directly on the regulatory decisions Mr. Harrington would make as PUC commissioner), the company may be unable to provide adequate funds to pay the pensions.*** This situation places Mr. Harrington in a direct and substantial conflict of interest on any regulatory matter involving or affecting Northeast Utilities, PSNH or their affiliates. ***How will Mr. Harrington remain neutral in fact (and be perceived by the public as remaining neutral) when his regulatory decisions materially affecting Northeast Utilities – for example, the upcoming PUC decisions on PSNH's accelerating loss of its customers and whether to approve the Northern Pass project that is so critical to Northeast Utilities's corporate strategy -- can so importantly affect his own wallet?***

Mr. Harrington's massive pension conflict absolutely disqualifies him from serving as PUC commissioner under the clear, unambiguous terms of RSA 363:5. To ensure an independent PUC, RSA 363:5 strictly prohibits any person with any financial interest in a regulated utility (even a single share of utility stock) from becoming a commissioner. ***It is beyond any serious argument that Mr. Harrington's present, vested right to a Northeast Utilities pension worth hundreds of thousands if not millions of dollars is a disqualifying financial interest under the statute.***

The Attorney General's contrary advice to the Executive Council misunderstands the financial realities of Mr. Harrington's pension and comes to an erroneous conclusion. We strongly disagree with the Attorney General's apparent suggestion that because these conflicts slipped through in the past, they should be allowed to do so again. Two wrongs don't make a right. ***The Executive Council is duty bound to uphold the law and to reject Mr. Harrington because of his disqualifying pension conflict.***

Any suggestion that Mr. Harrington should be confirmed with the understanding that he will recuse himself from matters involving Northeast Utilities, PSNH and their affiliates should be rejected. Mr. Harrington is flatly ineligible to serve as PUC commissioner under RSA 363:5 regardless of any undertakings he may make. And there would be no public benefit in having a neutered PUC commissioner who is unable to participate in huge swathes of the PUC's business.

B. BACKGROUND

After the Governor announced his PUC commissioner nominations, Councilor Ray Burton organized two public sessions in his district to give members of the public the opportunity to ask questions of the nominees. At both sessions, Mr. Harrington was questioned about his ties to the regulated utilities sector and specifically asked about past employment by utilities and any financial interests he may hold in utility companies. The public sessions showed a strong public interest in ensuring that PUC commissioners are fully independent of the utilities companies they regulate.

Mr. Harrington disclosed at the public sessions that he does in fact have substantial links to the utilities sector. He indicated that he had been employed for at least 21 years – the vast majority of his professional career -- at the Seabrook nuclear station. Mr. Harrington indicated that the Seabrook station had been owned for almost all of this period by PSNH, New Hampshire's largest regulated electric utility, and/or Northeast Utilities or its affiliates. One of the largest electric utilities in New England, Northeast Utilities is the parent company of PSNH. Mr. Harrington disclosed that he holds vested rights to a pension payable by Northeast Utilities with respect to his period of employment at Seabrook station.

Members of REAL and others expressed strong concerns about Mr. Harrington's pension. At the Twin Mountain public session, public input was to the effect that Mr. Harrington's pension constituted a financial interest in a regulated utility or utility affiliate that disqualified him from serving as a PUC commissioner. The same question arose at the Executive Council's hearing in Concord, and a member of REAL once again stated strong concerns about Mr. Harrington's pension.

Councilor Burton referred the pension conflict question to the Attorney General's office. The Attorney General's office issued a **letter dated February 22, 2012** that, with little detail, no financial analysis, questionable logic and reference to past practices, concluded that Mr. Harrington's pension was not a disqualifying financial interest. As detailed below, REAL believes that the Attorney General's analysis misunderstands the financial realities of the pension and that the conclusion is erroneous.

In order to assess the Attorney General's letter and to offer the Executive Council an alternative analysis, members of REAL **contacted Councilor Burton** and requested four simple, straightforward items of information that REAL believes are necessary for a robust analysis of the pension conflict. The information requested was (i) a copy of the plan covering Mr. Harrington's pension; (ii) the amount of the pension; (iii) the date the pension payments commence; and (iv) the identities of the utilities companies obligated on the pension.

REAL members believed that, having rendered an opinion letter on the pension conflict, the Attorney General's office would have this basic information in its files. Councilor Burton first requested the information from the Attorney General's office. The Attorney General's office indicated **by email** that it did not have the information.

Councilor Burton then requested the information from Mr. Harrington. Mr. Harrington, **via email**, categorically refused to provide the pension information. The text of Mr. Harrington's response is as follows:

"Councilor Burton, I believe the legal issues associated with my pension from the time I worked at Seabrook Station were adequately addressed by the Attorney General. As to the significance of the pension to me, this question cannot be answered simply by stating the amount of my future pension. The significance of this pension to me would have to be judged not only by its amount but by its amount relative to my net financial worth. There is no requirement or practice for those nominated for PUC Commissioner to disclose their net financial worth and therefor [sic] I do not intend to do so."

C. MR. HARRINGTON SHOULD NOT BE CONFIRMED BASED ON HIS CHARACTER, TEMPERAMENT, VALUES AND DISRESPECT FOR THE EXECUTIVE COUNCIL AND THE PUBLIC

REAL is shocked by the combative, defiant and disrespectful tone and substance of Mr. Harrington's response to Councilor Burton. We believe Mr. Harrington's flat refusal to cooperate with Councilor Burton's effort to obtain the most basic information about the pension conflict (copy of plan, pension amount, payment date, and corporate obligors) is simply indefensible in the context of the Executive Council's duty to consider and determine whether to confirm PUC nominees.

This is stonewalling at its best, and it raises the obvious question of what facts Mr. Harrington may wish to hide from public scrutiny. For example, why would Mr. Harrington refuse to provide a copy of the pension plan? Why would Mr. Harrington (having indicated publicly that his pension is payable by Northeast Utilities) now refuse to state the names of the public utilities or other companies obligated on the pension? And why categorically refuse to disclose the pension amount and payment terms? Is the amount of the pension payment potentially so substantial that Mr. Harrington fears disclosing the amount, because it will make the existence of a financial conflict completely obvious? These are of course mere speculations, but Mr. Harrington refuses to shed any light on the questions.

And why would Mr. Harrington distort the questions asked by Councilor Burton? For example, Councilor Burton asked for the amount of the pension. He did not ask for Mr. Harrington's net worth, as Mr. Harrington seems to suggest. Contrary to Mr. Harrington's protestations, the significance of Mr. Harrington's pension conflict can easily be assessed by reference to the pension amount by itself. REAL would submit that a pension that is actuarially expected to pay at least $100,000 in the aggregate (that is, an amount roughly the equivalent of one year's salary of a PUC commissioner) is by definition material in this context. For reference (and to use a hypothetical illustration we believe is well within the realm of possibility for Mr. Harrington – see below), a utility pension of $20,000 per year that is actuarially expected to be paid for 25 years has an aggregate payout of $500,000, equivalent to roughly 5 years of salary of a PUC commissioner. Surely the existence of a vested right for a PUC commissioner nominee to receive $500,000 (or any amount of comparable magnitude) from a regulated utility or utility affiliate should receive strict scrutiny in the confirmation process.

Mr. Harrington refuses to answer any of these questions. He appears to have no respect for the confirmation process, the Executive Council or the public, and no interest in getting the key facts on the table to enable the Executive Council to assess the pension conflict.

REAL believes Mr. Harrington's response shows a character, temperament and value system that is inconsistent with the public trust placed in PUC commissioners. On this basis alone, we believe the Executive Council should reject Mr. Harrington's nomination.

D. <u>MR. HARRINGTON SHOULD NOT BE CONFIRMED DUE TO HIS SUBSTANTIAL LINKS TO THE REGULATED UTILITY SECTOR AND PERCEIVED LACK OF INDEPENDENCE</u>

In recent years the PUC has dealt with many high-profile matters that have real day-to-day effects on ratepayers and their pocketbooks. As a result, public knowledge of and interest in the PUC and its activities have markedly increased. Across the state, citizens and ratepayers have closely followed PUC matters such as the Fairpoint transaction, storm-related outages, the Bow scrubber, the Berlin biomass facility, annual rate cases and Northern Pass.

Public sensitivity is high to appearances of independence and fairness at the PUC. Recently, public complaints have become more frequent about the perception of a "captured" PUC doing the bidding of regulated utilities at the expense of ratepayers and the public. The public expects a PUC that consists of commissioners who are independent and conflict-free and who also build public confidence by avoiding any appearance or perception of undue linkages with regulated utilities. While the statutory independence and disqualification standards for PUC commissioners set a minimum standard, the public justifiably expects the most rigorous approach to independence and conflicts. It is a political question for the Governor and the Executive Council to determine, as part of the PUC commissioner appointment process, what additional standards to apply in the public interest.

REAL believes Mr. Harrington's close and substantial linkages with the utilities sector go too far and are dangerously inconsistent with public confidence in the independence and integrity of the PUC. We believe the public will strenuously object to Mr. Harrington's pension and prior employment links.

We would pose the political question facing the Executive Council as follows, again using an example we believe to be well within the realm of possibility for Mr. Harrington:

Does the Executive Council wish to risk the erosion of public confidence, increased public perceptions of a utility-captured PUC and a strong public backlash by confirming a PUC commissioner who likely stands to receive future payments of $500,000 or more from a regulated utility or utility affiliate?

We believe to ask the question is to answer it. A future utility payment stream of this nature irrevocably clouds any public perception of independence. The perception issue is substantially worsened when the nominee in question has worked the vast majority of his career (21+ years) for regulated utilities or their affiliates. The public will almost surely conclude that Mr. Harrington stands for the utilities, not for ratepayers or the public interest.

The fact that Mr. Harrington was previously appointed a PUC commissioner on a temporary basis although he holds a utility pension and that others have been appointed to the PUC even though they hold utility pensions is a negative for public perceptions, not a positive. The existence of the utility pensions and the resulting conflict is not a matter of public consciousness. When the facts become more broadly known, the public will almost certainly feel that the pensions were hidden and that public trust was betrayed.

For these reasons, the Executive Council should reject Mr. Harrington's nomination.

E. MR. HARRINGTON IS DISQUALIFIED BECAUSE HIS PENSION IS A PROHIBITED FINANCIAL INTEREST IN A REGULATED UTILITY OR UTILITY AFFILIATE

1. Factual Background, Assumptions and Financial Materiality of the Utilities Pension

Mr. Harrington disclosed to the public that he has a vested right to receive a pension from Northeast Utilities with respect to his 21+ years of employment at Seabrook Station. He disclosed that the pension becomes payable in several years.

Mr. Harrington has subsequently refused to provide a copy of the pension plan to the Executive Council or to disclose to the Executive Council the amount of the pension, the commencement date of pension payments or the utility companies obligated to pay the pension.

For purposes of our analysis, we must therefore make several assumptions. Per Mr. Harrington's disclosures, we first assume that his pension is payable by Northeast Utilities, a utility itself and the parent company of PSNH. We assume that pension payments will commence in seven years. We assume that the general pension terms and conditions (other than payment amounts and timing) and pension funding status correspond to those for **Northeast Utilities's consolidated pension plan**.

As for annual pension payment amounts, we have reviewed publicly available information on compensation levels for nuclear engineers and general industry practice on pensions. On this basis, we assume that Mr. Harrington's annual pension is likely to be in the range of $20,000 to $70,000 per year, with the specific amount determined by actual compensation, payment elections, specific plan terms and other variables.

As for the actuarial expectation for the duration of Mr. Harrington's pension payments, we have reviewed various life expectancy tables and we assume that the actuarially expected duration of payments is likely to be in the range of 20 to 25 years.

We can offer no assurance that our assumptions conform to the actual facts of Mr. Harrington's pensions, but we believe the assumptions have a rational basis for purposes of illustrating the analysis of the disqualifying financial interest. We emphasize that all of the uncertainty would disappear if Mr. Harrington were willing to respond to Councilor Burton's factual inquiries.

Based on the above facts and assumptions, we would note the following:

- On the low side, Mr. Harrington stands to receive a stream of payments from the Northeast Utilities pension plan of $400,000 over 20 years ($20,000 per year) commencing 2019
- On the high side, Mr. Harrington stands to receive a stream of payments from the Northeast Utilities pension plan of $1,750,000 over 25 years ($70,000 per year) commencing 2019
- The low estimate ($20,000 per year for 20 years or $400,000 total) represents an aggregate payment amount equivalent to roughly four times (4x) the annual PUC

commissioner salary. Each year's pension payment is equal to roughly 20% of the annual PUC commissioner salary

- The high estimate ($70,000 per year for 25 years or $1,750,000 total) represents an aggregate payment amount equivalent to roughly 17.5 times (17.5x) the annual PUC commissioner salary. Each year's pension payment is equal to roughly 70% of the annual PUC commissioner salary
- The low estimate ($20,000 per year) is equivalent to roughly 31% of the median annual household income in New Hampshire (2010) of $65,028. The aggregate payment amount ($400,000) is equivalent to roughly 270% of median household net worth in New Hampshire (2009) of $148,350, 158% of median NH owner-occupied home value (2010) of $253,200, and 915% of the median US 401(k) retirement plan balance (2008) of $43,700
- The high estimate ($70,000 per year) is equivalent to roughly 108% of the median NH household income (2010) of $65,028. The aggregate payment amount ($1,750,000) is equivalent to roughly 1180% of NH median household net worth (2009) of $148,350, 691% of median NH owner occupied home value (2010) of $253,200, and 4005% of the median US 401(k) retirement plan balance (2008) of $43,700
- In the current low interest rate environment, the present value (that is, today's financial value) of the future pension payment stream commencing in 7 years is only a modest discount to the face amount of the pension obligation

These numbers paint a clear, unambiguous picture. No matter how the numbers are sliced or diced, Mr. Harrington's utilities pension is financially material in terms of public realities and public perceptions. The utilities pension is highly material in terms of Mr. Harrington's potential income level as a PUC commissioner.

With all due respect to any other analysis, we could stop here having demonstrated the point that Mr. Harrington's utilities pension is almost certainly a material financial interest as against any reasonable measure. We'll continue, however, in order to put the utilities pension in the proper context for purposes of the statutory disqualification under RSA 363:5, and to address what we believe are the mistakes in the Attorney General's analysis.

2. The Utilities Pension is a Disqualifying Interest under RSA 363:5

RSA 363:5 provides as follows: "No person who owns stock in, or is employed by or otherwise pecuniarily interested in any public utility in this state, or any affiliate thereof, shall be appointed upon said commission."

The wording is not ambiguous. The statute provides a very strict standard. A PUC commissioner nominee who owns a single share of stock in Northeast Utilities (last traded at $36.51 on March 5, 2012) is disqualified. There is no "materiality" test or other overlay. The plain words of the statute govern.

As regards Mr. Harrington's pension from Northeast Utilities, the only interpretive issue is whether Mr. Harrington's current vested right to the pension makes him "pecuniarily interested" in Northeast

Utilities, an affiliate of a New Hampshire utility. Following the practice of the New Hampshire Supreme Court, we consult the dictionary. Webster's online dictionary defines "pecuniary" as "consisting of or measured in money" or "of or relating to money." In other words, is the utility's pension a financial or money interest, or is it some other kind of interest, say a family interest or a love interest? We believe the answer is obvious – a pension is a financial interest, measured in money, relating to money.

As noted above, RSA 363:5 is a strict statute without any exception for materiality. Having concluded the utility's pension is a present pecuniary interest, there is no need to investigate whether it is big or small or material or immaterial to the holder or any other individual. **Just as Mr. Harrington would be disqualified if he owned a single share of Northeast Utilities common stock, he is disqualified by virtue of owning a Northeast Utilities pension.**

We emphasize that this clear, unambiguous result is not forever etched in stone. If the Governor, the Executive Council or the PUC feels that RSA 363:5 is too strict, nothing prevents an approach to the legislature to seek an amendment. The statute could be amended, for example, to provide a materiality test, a minimum financial threshold, or even an exclusion for pensions. As of today, however, the Executive Council is duty-bound by the oath of office to uphold the laws of the state, and RSA 363:5 clearly disqualifies Mr. Harrington by virtue of his Northeast Utilities pension.

For the avoidance of doubt, we will now address three potential misunderstandings as to the financial realities of pensions that could result in a misinterpretation of RSA 363:5.

First, because a Mr. Harrington's pension is payable in the future it may be misconstrued as not being a current financial interest in a utility. This misunderstanding is easily addressed by thinking about a corporate bond, specifically a zero-coupon bond. A zero coupon bond is a standard corporate debt obligation that is payable in a single lump sum (principal plus accrued interest) on a single payment date in the future. There are no current interest payments; rather, accrued interest is added to principal. Imagine that Mr. Harrington owns $400,000 to $1,750,000 face amount of Northeast Utilities zero coupon bonds payable in seven years. He presently owns the bonds, just as he presently owns the pension. The bonds, even though they are payable in the future, are obviously a current financial interest in Northeast Utilities. For this purpose, Mr. Harrington's pension is precisely analogous.

Second, because Mr. Harrington's pension has a fixed payment amount and schedule that has already been determined under the applicable pension plan, the pension may be misconstrued as "not being like common stock" because it is not variable. This is irrelevant to the proper classification of the pension as a financial interest. Again, reference to a traditional financial interest, a corporate bond, demonstrates the analysis. A corporate bond, unlike a share of stock, but like a pension, has a stated payment amount and schedule. There can be no serious argument that a corporate bond, because of the fixed payments, is not a financial interest. The same holds for a pension.

Third, because a pool of investment securities has been set aside to contribute toward funding Northeast Utilities's pension obligations, the pension may be misconstrued as not constituting a financial interest in Northeast Utilities. This is factually incorrect. The pool of investment securities has a value that varies over time. Northeast Utilities has assumed the obligation to fund the pensions. See, for example, Section 10.1 of the **Northeast Utilities pension plan**, which obligates the company to make contributions to the plan "in such amounts as may be determined to be necessary to fund the Plan." The pension obligations perform like unsecured credit obligations of Northeast Utilities, that is, like a corporate bond.

This point is emphasized by the current underfunded status of the Northeast Utilities pension plan. As reported in **recent research by Goldman Sachs**, Northeast Utilities' pension plan is among the most materially underfunded among large US companies. In other words, the value of the pool of investment securities set aside in the pension trust is much less than the current value of the pension obligations (including, per our assumptions, Mr. Harrington's pension). The funding shortfall as reported by Goldman Sachs is close to $1 billion and is highly material to Northeast Utilities's financial position and results. To be sure this point is understood, if the pension plan were terminated today, there would not be enough money to pay all the pensions. If Northeast Utilities suffers business reversals or goes bankrupt, pension obligations may not be funded by the company, and the underfunding shortfall may grow. This is made an express term of the **Northeast Utilities pension plan** in Section 14.1, which provides that "the Company maintains the right to suspend, terminate, or completely discontinue contributions under the Plan." **For pension holders such as Mr. Harrington, the practical consequence is that his investment experience as a holder of a vested pension depends materially on the credit of Northeast Utilities, just as would the investment of a bondholder**.

3. The Attorney General's Opinion Letter Appears to be Based on Key Misunderstandings and Comes to an Erroneous Conclusion

As demonstrated above, Mr. Harrington's pension as described by him in public testimony is clearly a present "pecuniary interest" in a utility or utility affiliate that disqualifies him from serving as a PUC commissioner under RSA 363:5. We now address four apparent misunderstandings in the **Attorney General's opinion letter**, which led the Attorney General to come to a contrary conclusion.

First, the Attorney General appears to misunderstand the fundamental nature of the pension as substantially equivalent to a corporate bond (that is, dependent on the company's financial results) in terms of the holder's investment expectations.

The Attorney General notes, as if it were significant, that the pension is (x) a "defined benefit plan [sic]" that (y) is "administered by a third party (Aetna)." Neither of these factors is relevant to the substance of the pension obligation or the importance of Northeast Utilities's financial performance to the safety of the pension obligation. A defined benefit pension means simply that the pension payment schedule (amounts and timing) is fixed in advance, just like the payment schedule of a corporate bond. The fact that there is a pension plan administrator is meaningless. As noted above, the Northeast Utilities pension plan (which has a third party administrator) is based as a credit matter on continued contributions by Northeast Utilities. The administrator is merely an administrator, and this role is irrelevant to investment expectations.

The Attorney General next asserts that "future benefits have been determined and are not subject to change based upon the financial performance of PSNH, Northeast Utilities or FPL Group." This assertion that future benefits are not subject to change based on financial performance of the plan sponsors is, we believe, simply in error. We have demonstrated above that Northeast Utilities's pension plan is materially underfunded (there are not enough assets to pay all benefits) and that the company reserves the right to suspend future contributions. Thus, by definition the payment experience of a pension holder such as Mr. Harrington depends on the financial performance of Northeast Utilities.

We note that the factual statements in the Attorney General's opinion differ from the disclosures made by Mr. Harrington. For example, Mr. Harrington stated his pension is payable by Northeast Utilities, while the Attorney General suggests that there may be three pension obligors (Northeast Utilities, PSNH and FPL Group). This factual confusion underscores the need for full and accurate disclosure of the material facts of the pension. In this regard, we would highlight the **email correspondence from the Attorney General's office** indicating that it does not have a copy of the pension plan nor does it have the basic pension information requested by Councilor Burton.

Second, based on what we believe to be the misunderstanding described above, the Attorney General's opinion states that because Mr. Harrington's pension "is not based on the financial performance of a public utility," the statutory disqualification "does not apply to him." We believe we have demonstrated that the pension in fact does materially depend on the credit and financial performance of Northeast Utilities. We therefore believe the Attorney General is in error on this point and RSA 363:5 fully applies to the pension.

Third, the Attorney General refers to two prior cases (Commissioner Getz and Mr. Harrington during his prior temporary tenure as a PUC commissioner) in which a sitting commissioner owned a vested PSNH pension. The Attorney General appears to suggest that these past two cases somehow demonstrate that the pension conflict is a customary practice and thus justified. With all due respect, past deviation from the strict disqualification standards of RSA 363:5 cannot be used to justify any continuing disregard of those disqualification standards. Only the legislature can change the law. The statutory authority regarding appointment of PUC commissioners is not something that any state official has the ability to alter or avoid.

Fourth, the Attorney General suggests a creative interpretive overlay to RSA 363:5 that a vested pension is not "an ongoing financial interest in, or relationship to, an entity that may appear before the nominee" and is therefore not a disqualifying interest.

With all due respect, this is creating something out of whole cloth. Let's once again compare a pension and a corporate bond and use the comparison to test the Attorney General's proposed interpretation. If we understand, the Attorney General is positing that pensions are "prior connections" rather than "ongoing financial interests." By that logic, if Mr. Harrington had purchased $400,000 of Northeast Utilities bonds a few years ago, and is now before the Executive Council for confirmation as a PUC commissioner, he could argue that the purchase was a "prior connection" and his present ownership of the bonds is somehow not "ongoing" and should be disregarded (particularly if Commissioner Getz also owned a portfolio of Northeast Utilities bonds and Mr. Harrington did too during his prior tenure). To state the position is to show it has no underlying logic. A present ownership interest of a corporate bond is a present financial interest in the bond issuer, just as a present ownership interest in a pension is a present financial interest in the pension obligor.

Accordingly, we believe the Attorney General's opinion lacks a factual basis and comes to a clearly erroneous conclusion.

We note that there are at least some potential circumstances in which Mr. Harrington's pension would not constitute a financial interest in Northeast Utilities. For example, if the pension obligation had been converted into an annuity payable by a third party insurance company, the pension, per the terms of Section 13.6 of the Northeast Utilities pension plan, would represent a claim solely against the insurance company. Again, the existence of potentially alternative fact patterns emphasizes the need for full and accurate disclosure of the details of Mr. Harrington's pension.

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For the reasons set forth above, REAL respectfully requests the Executive Council to reject Mr. Harrington's nomination.

Respectfully submitted,

RESPONSIBLE ENERGY ACTION LLC

By: Susan Schibanoff, Managing Member
Alan Robert Baker, Member
Jim Dannis, Member
Sandy Dannis, Member
Tim Duggan, Member
Neil Irvine, Member
Bill Schomburg, Member

EXHIBIT 4

August 15, 2011

Global Markets Institute

Markets take their toll on pension funded status

Goldman Sachs

Global Markets Institute

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Funded status takes a fall

Declining equity prices and long-term interest rates, which raise the present value of pension obligations, are hitting DB pension plan sponsors with a "double whammy". This is eerily similar to late 2008. We estimate that the aggregate funded status of US plans for S&P 500 companies has fallen to about 75% as of mid-August from 85% at the beginning of 2011. Some companies are contributing cash to increase funded levels, using either excess cash on their balance sheets or taking advantage of low interest rates to issue new debt.

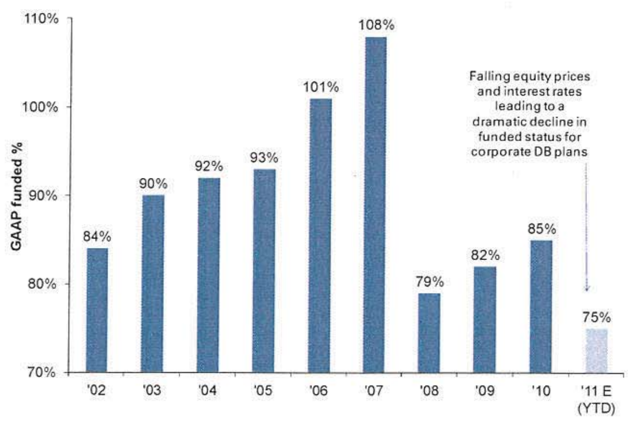
Pension palpitations re-emerge

Investors have, once again, turned their focus to companies that may have pension-related stresses given the recent declines in funded status. Our pension palpitation screens, first introduced in 2008, help investors identify companies deserving special attention.

Public pension plans face stresses as well

The public DB pension universe is not immune to the fall in asset prices, although computational differences in the calculation of the pension liability do not leave them exposed to the decline in interest rates. Nonetheless, the many smoothing mechanisms in public DB funded calculations mean public DB funded ratios are likely to remain depressed for several years.

Falling equity prices and interest rates a bad mix for funded status
S&P 500, US plans only



Source: Goldman Sachs Global Markets Institute; Capital IQ; company reports.

The Global Markets Institute is the public policy research unit of Goldman Sachs Global Investment Research. Its mission is to provide research and high-level advisory services to policymakers, regulators and investors around the world. The Institute leverages the expertise of Research and other Goldman Sachs professionals, as well as highly-regarded thought leaders outside the firm, to offer written analyses and host discussion forums.

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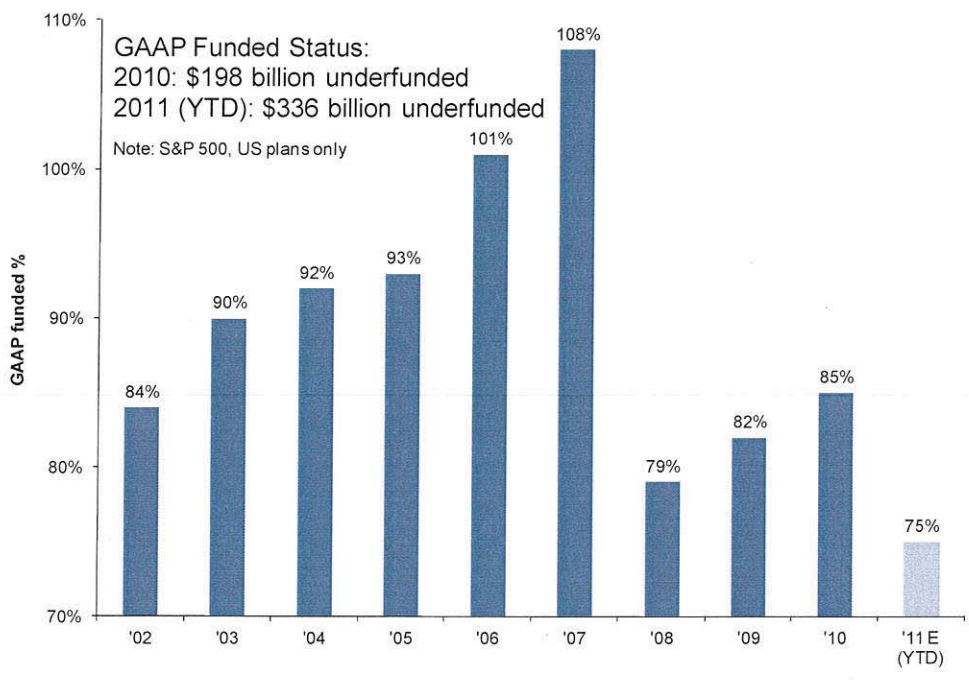
Dramatic downturn in funded status for many DB plans

Reversing the gains of recent years, and then some.

Aggregate funded status for the US plans of S&P 500 companies has declined to about 75% as of mid-August from 85% as of the beginning of 2011. As recently as earlier this summer the aggregate funded level stood at about 87%, highlighting how quickly and dramatically funded status has fallen. The funded ratio for the median US corporate plan is likely now below 70%.

As seen in Exhibit 1, the aggregate funded ratio is now below where it ended 2008, the most recent year-end trough. The slow, steady recovery in funded status that had been achieved over the past few years has been eliminated, and even reversed, over the course of a few weeks.

Exhibit 1: US DB funded status suffering from recent market volatility
S&P 500, US plans only



Source: Goldman Sachs Global Markets Institute; Capital IQ; company reports.

A repeat of late 2008 – equity prices and interest rates falling at the same time.

Exhibit 2 details our rollforward estimate of the aggregate assets and liabilities of US plans of S&P 500 companies. In this exercise we have taken aggregate DB plan assets and liabilities as of the beginning of 2011 and adjusted them for our estimates of actual results for the year to date. Many of these adjustments are moving dramatically on a daily basis. The rollforward calculations show that asset price declines combined with a fall in the discount rate have resulted in substantial reductions in funded status. By our estimate, the year-to-date increase in the aggregate underfunded amount for the S&P 500 is over $100 billion due to these two factors alone.

Exhibit 2: Both asset declines and liability increases causing funded status strain
S&P 500, US plans only

S&P 500 - US plans only
Analysis as of Mid-August, 2011
$ amounts in millions

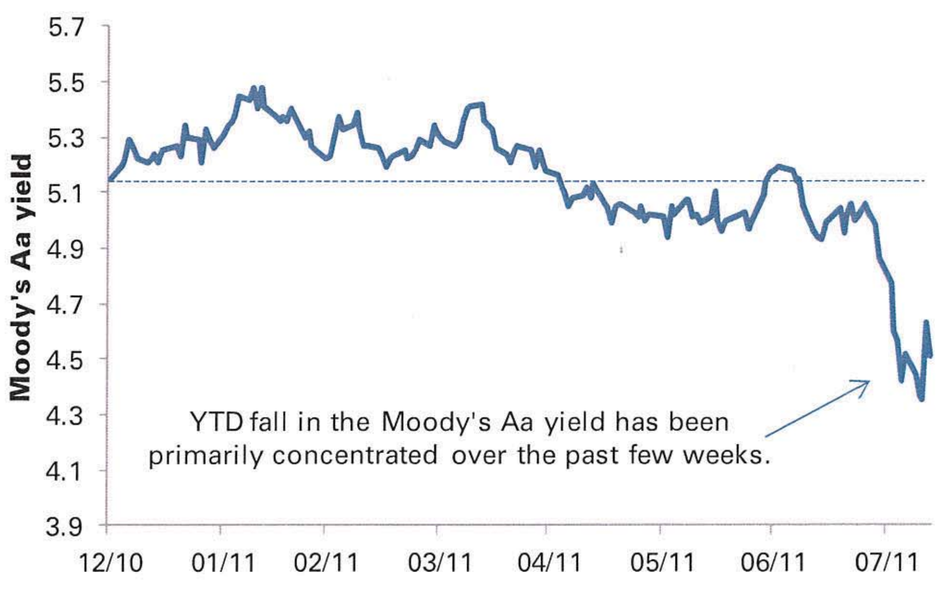
	Assets	Notes
Beginning of 2011	$1,088,493	Total US plan assets of S&P 500 companies
Actual Plan Asset Returns	(54,106)	Assumes (5)% 2011 YTD return
Contributions	35,000	YTD share of $60 billion annual estimate
Benefits Paid	(47,762)	YTD share of company-reported expected benefit payments in 2011
Mid-August 2011	1,021,626	
	Liabilities	
Beginning of 2011	1,286,450	Total US plan liabilities of S&P 500 companies
Actuarial Loss	63,679	Assume discount rates decline 45 bps (assumes plan duration of 11)
Interest Cost	40,523	YTD interest cost (2010 end of year discount rate (5.40%) * BOY liabilities (above))
Service Cost	14,258	YTD service cost (service cost was 1.9% of the pension obligation in 2009; apply that % to 2011's BOY liabilities (above))
Benefits Paid	(47,762)	Same as above
Mid-August 2011	1,357,149	
Funded Status	($335,524)	
Funded Ratio	75%	

Source: Goldman Sachs Global Markets Institute; Capital IQ; company reports.

Gross pension liabilities are rising due to the low interest rate environment.

While much of the focus in recent weeks has been on the sharp decline in equity prices, the dramatic decline in high-quality long-term interest rates has caused just as much, if not more, pressure on funded ratios. The Moody's Aa yield, a common benchmark for setting the accounting discount rate, has declined notably in just a few weeks and is now down about 50 basis points since the beginning of 2011 (see Exhibit 3). Other measures of high-quality long-term interest rates have fallen by similar amounts.

Exhibit 3: Falling interest rates leads to lower discount rates and higher pension liabilities
The year-over-year change is the key to the analysis



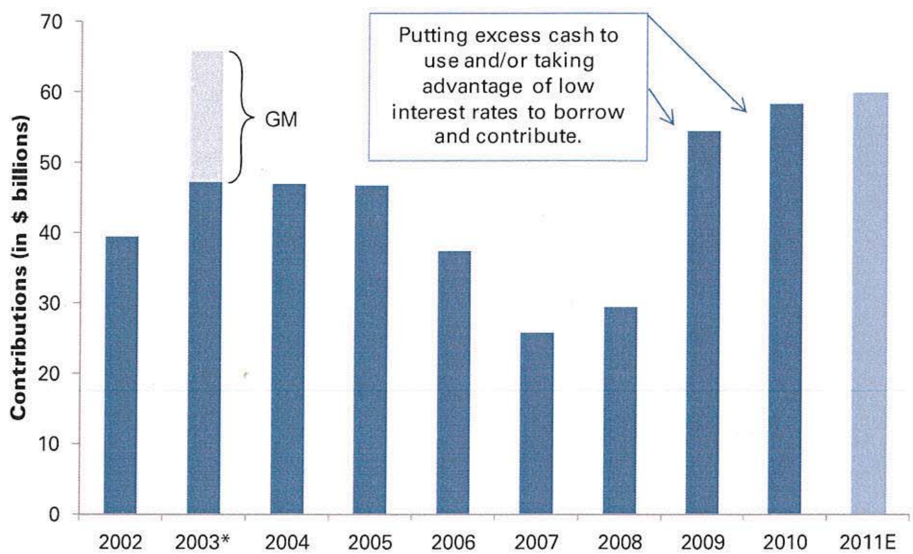
Source: Moody's; Bloomberg; Goldman Sachs Global Markets Institute.

Pension liabilities are expressed on a present value basis, with the discount rate used tied to the aforementioned high-quality long-term interest rates. As these rates fall, therefore, the present value of the pension obligation rises, lowering funded status. The impact on a specific company depends on the duration of its plan's liabilities. For example, a plan with duration of 10 years would see the present value of its pension obligations rise roughly 10% if its discount rate were to fall 100 bp.

Contribution activity likely to remain robust

Based on data disclosed by companies on their expected contributions during 2011, we project that contributions to US plans this year will likely exceed actual contributions made during 2009 and 2010 (see Exhibit 4). While this would help to offset some of the decline in funded status, these contributions are currently being overwhelmed by the decline in plan asset values and the increase in plan liabilities.

Exhibit 4: 2011 may be yet another peak year for contributions
S&P 500, US plans only



* General Motors alone contributed $18 billion to its US pension plans in 2003. This upwardly skewed total S&P 500 contributions for 2003.

Source: Goldman Sachs Global Markets Institute; Capital IQ; company reports.

Strong cash, low yields.

Large parts of these contribution amounts in recent years have been of a voluntary nature as some cash-rich plan sponsors contributed excess cash into their plans while others took advantage of historically low interest rates to issue debt and use part of the proceeds to increase funded levels. We expect more companies to take similar actions in 2011, even if they have no mandatory contribution requirements.

Contributions help plan sponsors on multiple levels.

As we have noted in previous publications, there are many benefits, both financial reporting and otherwise, from contributing cash into a DB pension plan. These include:

- Under current accounting rules, contributing cash into a DB pension plan is accretive as sponsors recognize income on plan assets based on their long-term expected return assumption, usually around 8%, which exceeds what cash is currently earning or the cost of issuing new debt to fund contributions. For additional information on changes to international accounting standards which may ultimately change this accounting in the United States, please see the box on page 8.

- Contributions to DB pension plans are tax deductible up to certain limits.
- Voluntary contributions may help to lower mandatory contributions in the future, thereby helping with planning and budgetary issues.
- Raising funded levels can help to minimize PBGC variable rate premiums and/or limitations on lump sum payments or benefit accruals due to low funding levels.
- For sponsors looking to de-risk their plans, increasing funded levels through contributions can help to expedite the implementation of liability driven investment (LDI) strategies.
- Finally, increasing funded levels through contributions can help to ease the concerns of investors, creditors, credit rating agencies and even a company's own workers and retirees with respect to an underfunded DB plan.

Using low interest rates to their advantage, some plan sponsors have issued debt to help increase funding levels.

Some sponsors over the past year have taken advantage of historically low interest rates to issue debt and contribute part of the proceeds to their DB plans. Companies undertaking such actions have included Dow Chemical, Northrop Grumman and UPS. We believe that more companies may take this approach. With all the negative ramifications that low interest rates have on the mechanisms of pension accounting and reporting, this is a way for plan sponsors to use low interest rates to the advantage of their plans.

In addition to the points above on contributions, note that issuing debt to fund a plan brings some added benefits, such as the tax deductibility of interest payments on the debt. In addition, while the Pension Protection Act generally requires funding deficits to be made up over seven years, issuing a longer-dated bond to fund the deficit allows the sponsor to pay off the debt over a longer time period. Finally, while some companies currently have substantial cash balances on their balance sheets, for some much of that cash may be held outside the United States. Issuing debt provides an avenue for funding a plan if repatriating cash from foreign operations would result in an additional tax liability.

Pressure on balance sheets, income statements and cash flow

Impact on the fundamental data used by investors and creditors.

If funded levels remain depressed through the end of a company's fiscal year, the impact will be felt on the sponsor's balance sheet at the end of the year and through the income statement in the subsequent year. Mandatory contribution requirements tend to have a lagged effect over a multi-year period, even under the tighter rules put in place by the Pension Protection Act of 2006.[1]

Because all of the accounting related to these plans occurs on the last day of a company's fiscal year, changes to funded status levels **during** the year do not have any affect on the current year's balance sheet or income statement. In other words, the recent decline in funded status for a calendar year company would not result in higher pension expenses in 3Q or 4Q of 2011.

The exception to this will be those companies that have changed their accounting to more of a "mark-to-market" framework. Such companies include Honeywell, AT&T and Verizon, which all moved their accounting in this direction during late 2010/early 2011. Although the specifics of their changes differed a bit from company to company, all of them will have

[1] Our proprietary Excel-based pension forecasting model, which we first introduced in our December 2008 "Pension accounting primer" report, can help investors model the impact on funded status and pension expense from changes in interest rates and asset values. Please contact us directly for the model or for a copy of the primer report. In addition, disclosures within the MD&A section of a company's 10-K will often provide sensitivity analysis for pension metrics, such as pension expense, for changes in assumptions such as the discount rate which can assist investors in evaluating the magnitude of such changes.

a 4Q earnings adjustment to account for actual plan asset returns during the year as well as adjustments to the gross pension obligation from a change in the discount rate.[2] Given recent market activity, those adjustments could be sizable losses, although we would expect the companies to adjust reported 4Q results for these items as part of pro forma earnings disclosures.

Point-in-time snapshot could change dramatically before year-end.

Our YTD aggregate funded status calculation detailed earlier in this report is, by definition, a snapshot at a point in time. With respect to a calendar year company, it really does not matter what funded status looks like in mid-August. What matters from a financial reporting perspective is what funded status looks like on the last day of the fiscal year. It is that funded status which will determine the balance sheet recognition of pension liabilities as well as the amount of pension expense that would need to be recognized through the income statement in the subsequent year.

Recall that during the summer of 2010 there was increased focus by investors on pension-related issues as long-term interest rates fell in anticipation of the Federal Reserve's QE2 program and as equity prices dipped during the months of July and August.[3] Nonetheless, an increase in long-term interest rates and equity prices during the last few months of 2010 improved funded ratios.

The aggregate funded ratio for US plans actually ended 2010 above where it had been at the end of 2009 (refer back to Exhibit 1 for our historical funded status series for the S&P 500). While investor concerns related to companies exposed to pension-related issues is warranted given recent market volatility, it is important to remember that a snapshot of a point in time is just that – a point in time. Any effects on the financial reporting of a calendar-year company will not ultimately be determined until several months from now, and much could change during that time.

[2] Honeywell may not have any 4Q as its accounting change still maintained the use of the "corridor."

[3] For additional information, please refer to our report of July 12, 2010 entitled "Accounting policy update: Recent pension palpitations linked to declining interest rates."

IASB's revision to international pension accounting removes an important barrier to de-risking

Recent changes to pension accounting standards by the International Accounting Standards Board (IASB) eliminate the use of the expected return assumption in pension expense calculations, thereby removing a powerful barrier to de-risking. Moving asset allocation to more of a fixed income focus as part of a de-risking strategy would result in a lowering of the expected return assumption. A hesitancy to lower this assumption, which would thereby increase pension expense and lower net income and EPS, has been cited by some plan sponsors in the United States as a difficult hurdle to overcome when considering de-risking strategies. Given the elimination of the use of the expected return assumption, asset allocation changes under the revised International Financial Reporting Standards (IFRS) will not have a direct and immediate effect on the amount of pension expense recognized by a plan sponsor as it does today under US GAAP.

These changes, which go into effect for IFRS in 2013, do not affect the way US companies account for their pension plans. However, the IASB's changes will likely either work their way into US GAAP in the coming years as the FASB moves to converge US GAAP with IFRS, or the SEC could allow or require the use of IFRS by US companies at a future date, such as around 2015.

The most recent twist to use of IFRS in the United States has centered around the idea of a "condorsement" approach. Under such an approach, put forth by the SEC in a proposal earlier this year, US GAAP would be maintained and the FASB would work to better converge it with IFRS. As the IASB issued new standards for IFRS, the FASB could choose to endorse them as part of US GAAP (hence, the proposal is a mix of converging and endorsement).

Whether IFRS is ultimately adopted in the United States or US GAAP pension accounting is converged closer to the new IFRS rules, US companies will likely be subject to a pension accounting framework similar to what has recently been issued by the IASB. However, depending on the path selected by the SEC, US companies could still be several years away from seeing this type of pension accounting framework becoming mandatory.

Given the decline in funded status discussed throughout this report, many plans that had not previously moved to de-risk are likely to be unable to do so at this time as they are more focused on seeking return-generating assets to improve funded levels. However, as funded status improves over time and if the expected return assumption is no longer a factor in pension expense calculations, we would expect de-risking activities to increase.

Note that in the 2006/2007 time period some plans that were overfunded (and closed/frozen) did not take actions at that time to de-risk their plans. It is possible that an unwillingness to lower the expected return assumption as part of a de-risking strategy, and see pension expense rise, could have played a role in such inaction. As funded status (hopefully) improves for plans over the next several years and approaches 100%, a removal of the expected return assumption from the pension expense calculations would help pave the way for quicker implementation of de-risking actions.

Identifying companies exposed to pension-related issues

Where should investors be focusing their attention when looking at pensions?

In October 2008 we first introduced our "Pension Palpitation" screens in an effort to help investors focus their attention on which companies may be experiencing pension-related stresses. As much as we would like to retire these screens, the recent volatility in the capital markets has once again raised pension issues up the list of concerns among investors. As such, we have detailed updated versions of these screens on the following pages.

All of the pension-related data for the companies in our screens relate to the US plans of S&P 500 companies, and all of the data is as reported by the companies at the end of fiscal 2010. Consequently, the actual funded status of many of these plans has likely to have deteriorated, in some cases notably, since the end of 2010. **The purpose of the screens is to help point investors towards companies that should be on their radar screens for further investigation.** Therefore, while funded status has likely fallen for all of these companies, the relative rankings of companies under each of these screens has likely not changed that much even if we had real time funded status data for each plan.

Six screens.

Below we review each of the screens and why investors may find them particularly useful.

Exhibit 5 – Highest % of pension obligations to market capitalization: Materiality trumps almost everything. Several companies may have plans that are small on an absolute basis, but large in relation to the size of the company (and vice versa). This materiality screen helps to identify those companies where pension-related issues may have an outsized impact on the plan sponsor. While we use PBO to market cap as our measure of materiality for the purposes of this screen, other measures, such as PBO to book value, could also be informative.

Exhibit 6 – Largest US defined benefit pension plans by asset size: These are the "usual suspects" given the size of their plans, but as noted above, for some the plan may be relative small in relation to the plan sponsor even if it is large on an absolute basis.

Exhibit 7 – Lowest GAAP funded ratio: Companies with the lowest funded ratios, which have likely moved lower since the end of 2010, may see mandatory contribution requirements increase in the coming years.

Exhibit 8 – Largest dollar amount of GAAP underfunding: The dollar amount of underfunding has likely ballooned for some companies, and many on this list already began the year with multi-billion dollar deficits.

Exhibit 9 – Largest unrecognized losses as of the end of 2010: Changes in funded status that have not yet been recognized through earnings are "unrecognized" and may be recognized as expenses in future periods. These unrecognized losses have likely risen in 2011, given higher pension obligations from lower discount rates and actual plan asset losses. This increases the chance of more losses becoming recognized in future years, leading to upward pressure on pension expense and downward pressure on EPS.

Exhibit 10 – Highest % of unrecognized losses to market capitalization: Again, materiality matters. This screen identifies those companies for whom unrecognized losses already represented a relatively high percentage of the company's market capitalization. These percentages have likely moved higher given additional unrecognized losses generated in 2011.

Exhibit 5: Highest % of pension obligations to market capitalization

Several companies have gross pension obligations that exceed the company's equity market capitalization

Sorted by PBO to market cap
$ amounts in millions
All companies with obligation as a % of market cap. => 40%
US plans only
All pension data as of 2010

				US Plans					
Ticker	Company Name	Industry	Month of Fiscal Year end	Pension Expense/ (Income)	Obligation	Assets	GAAP Funded Status	GAAP Funded %	PBO as a Percentage of Market Capitalization (as of 8/8/11)
AKS	AK Steel Holding Corporation	Steel	12	23	3,529	2,473	(1,056)	70%	379%
X	United States Steel Corp.	Steel	12	220	10,630	8,655	(1,975)	81%	244%
GT	Goodyear Tire & Rubber Co.	Tires and Rubber	12	219	5,641	3,714	(1,927)	66%	186%
NOC	Northrop Grumman Corporation	Aerospace and Defense	12	595	25,263	23,265	(1,998)	92%	171%
SVU	SUPERVALU Inc.	Food Retail	2	87	2,515	1,896	(619)	75%	166%
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	1,442	35,773	25,345	(10,428)	71%	150%
RRD	R.R. Donnelley & Sons Company	Commercial Printing	12	34	3,583	3,030	(554)	85%	130%
BA	Boeing Co.	Aerospace and Defense	12	1,367	59,106	49,252	(9,854)	83%	128%
RTN	Raytheon Co.	Aerospace and Defense	12	894	18,407	14,502	(3,905)	79%	126%
TXT	Textron Inc.	Industrial Conglomerates	1	126	5,877	4,559	(1,318)	78%	121%
F	Ford Motor Co.	Automobile Manufacturers	12	122	46,647	39,960	(6,687)	86%	113%
GCI	Gannett Co., Inc.	Publishing	12	54	2,539	2,001	(538)	79%	101%
AA	Alcoa, Inc.	Aluminum	12	233	12,343	9,451	(2,892)	77%	95%
IP	International Paper Co.	Paper Products	12	231	9,824	8,344	(1,480)	85%	91%
JCP	J. C. Penney Company, Inc.	Department Stores	1	255	4,710	5,251	541	111%	83%
SHLD	Sears Holdings Corporation	Department Stores	1	120	5,623	4,054	(1,569)	72%	81%
WHR	Whirlpool Corp.	Household Appliances	12	40	3,605	2,288	(1,317)	63%	79%
OI	Owens-Illinois, Inc.	Metal and Glass Containers	12	36	2,437	2,195	(242)	90%	79%
R	Ryder System, Inc.	Trucking	12	35	1,744	1,429	(315)	82%	76%
PCG	PG & E Corp.	Multi-Utilities	12	164	12,071	10,250	(1,821)	85%	75%
ED	Consolidated Edison Inc.	Multi-Utilities	12	453	10,307	7,721	(2,586)	75%	68%
MWV	MeadWestvaco Corporation	Paper Products	12	(72)	2,843	3,756	913	132%	63%
ITT	ITT Corporation	Aerospace and Defense	12	70	5,364	4,272	(1,092)	80%	62%
DOW	The Dow Chemical Company	Diversified Chemicals	12	502	21,158	15,851	(5,307)	75%	61%
WY	Weyerhaeuser Co.	Specialized REITs	12	(47)	5,267	4,773	(494)	91%	57%
FDX	FedEx Corporation	Air Freight and Logistics	5	308	13,983	13,055	(928)	93%	55%
DD	El DuPont de Nemours & Co.	Diversified Chemicals	12	557	23,924	18,403	(5,521)	77%	55%
CSC	Computer Sciences Corporation	Data Proc. and Outsourced Svcs.	4	47	2,702	2,088	(614)	77%	55%
PNW	Pinnacle West Capital Corp.	Electric Utilities	12	78	2,345	1,776	(569)	76%	54%
HIG	Hartford Financial Services Group Inc.	Multi-line Insurance	12	166	4,795	3,922	(873)	82%	53%
AEE	Ameren Corporation	Multi-Utilities	12	65	3,451	2,722	(729)	79%	53%
DNB	Dun & Bradstreet Corp.	Research and Consulting Svcs.	12	6	1,709	1,278	(431)	75%	52%
NU	Northeast Utilities	Electric Utilities	12	85	2,821	1,978	(843)	70%	50%
POM	Pepco Holdings, Inc.	Electric Utilities	12	70	1,970	1,632	(338)	83%	49%
DTE	DTE Energy Co.	Multi-Utilities	12	112	3,785	2,913	(872)	77%	49%
ATI	Allegheny Technologies Inc.	Steel	12	71	2,294	2,237	(56)	98%	46%
NI	NiSource Inc.	Multi-Utilities	12	81	2,478	1,900	(578)	77%	46%
EXC	Exelon Corp.	Electric Utilities	12	324	12,524	8,859	(3,665)	71%	46%
SLE	Sara Lee Corp.	Packaged Foods and Meats	7	115	4,727	4,197	(530)	89%	45%
COL	Rockwell Collins Inc.	Aerospace and Defense	9	26	3,354	2,169	(1,185)	65%	45%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	117	6,173	4,320	(1,853)	70%	44%
CMS	CMS Energy Corp.	Multi-Utilities	12	114	2,014	1,401	(613)	70%	44%
AET	Aetna Inc.	Managed Healthcare	12	164	5,821	5,244	(577)	90%	42%
WPO	The Washington Post Company	Publishing	12	3	1,193	1,652	459	139%	42%
ALL	The Allstate Corporation	Property and Casualty Ins.	12	297	5,545	4,669	(876)	84%	42%
PBI	Pitney Bowes Inc.	Office Services and Supplies	12	38	1,632	1,385	(247)	85%	42%
HON	Honeywell International Inc.	Aerospace and Defense	12	301	14,990	12,181	(2,809)	81%	41%
GD	General Dynamics Corp.	Aerospace and Defense	12	166	9,238	6,250	(2,988)	68%	41%
PPG	PPG Industries Inc.	Diversified Chemicals	12	161	4,952	4,127	(825)	83%	41%
CI	CIGNA Corporation	Managed Healthcare	12	17	4,691	3,163	(1,528)	67%	40%
TEG	Integrys Energy Group, Inc.	Multi-Utilities	12	41	1,419	1,081	(337)	76%	40%
ETR	Entergy Corporation	Electric Utilities	12	147	4,301	3,216	(1,085)	75%	40%

Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 6: Largest US defined benefit pension plans by asset size

Many of these companies are the "usual suspects" with regard to pension issues

Sorted by plan assets
$ amounts in millions
All companies with pension assets => $4 billion
US plans only
All pension data as of 2010

					US Plans				
Ticker	Company Name	Industry	Month of Fiscal Year end	Pension Expense/ (Income)	Obligation	Assets	GAAP Funded Status	GAAP Funded %	PBO as a Percentage of Market Capitalization (as of 8/8/11)
IBM	International Business Machines Corp.	IT Consulting and Other Svcs.	12	(935)	51,293	50,259	(1,034)	98%	25%
BA	Boeing Co.	Aerospace and Defense	12	1,367	59,106	49,252	(9,854)	83%	128%
T	AT&T, Inc.	Integrated Telec. Services	12	2,536	56,187	47,621	(8,566)	85%	33%
GE	General Electric Co.	Industrial Conglomerates	12	1,072	51,999	44,801	(7,198)	86%	31%
F	Ford Motor Co.	Automobile Manufacturers	12	122	46,647	39,960	(6,687)	86%	113%
VZ	Verizon Communications Inc.	Integrated Telec. Services	12	(83)	29,217	25,814	(3,403)	88%	30%
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	1,442	35,773	25,345	(10,428)	71%	150%
NOC	Northrop Grumman Corporation	Aerospace and Defense	12	595	25,263	23,265	(1,998)	92%	171%
UTX	United Technologies Corp.	Aerospace and Defense	12	218	24,445	22,384	(2,061)	92%	38%
UPS	United Parcel Service, Inc.	Air Freight and Logistics	12	573	21,342	20,092	(1,250)	94%	34%
DD	EI DuPont de Nemours & Co.	Diversified Chemicals	12	557	23,924	18,403	(5,521)	77%	55%
BAC	Bank of America Corporation	Other Diversified Financial Svcs.	12	302	17,016	18,337	1,321	108%	22%
DOW	The Dow Chemical Company	Diversified Chemicals	12	502	21,158	15,851	(5,307)	75%	61%
RTN	Raytheon Co.	Aerospace and Defense	12	894	18,407	14,502	(3,905)	79%	126%
JNJ	Johnson & Johnson	Pharmaceuticals	12	583	14,993	13,433	(1,560)	90%	9%
FDX	FedEx Corporation	Air Freight and Logistics	5	308	13,983	13,055	(928)	93%	55%
HON	Honeywell International Inc.	Aerospace and Defense	12	301	14,990	12,181	(2,809)	81%	41%
MMM	3M Co.	Industrial Conglomerates	12	144	12,319	11,575	(744)	94%	21%
C	Citigroup, Inc.	Other Diversified Financial Svcs.	12	(170)	12,388	11,561	(827)	93%	13%
XOM	Exxon Mobil Corporation	Integrated Oil and Gas	12	1,388	15,007	10,835	(4,172)	72%	4%
JPM	JPMorgan Chase & Co.	Other Diversified Financial Svcs.	12	138	8,320	10,828	2,508	130%	6%
CAT	Caterpillar Inc.	Const., Farm Mach. and Trucks	12	527	13,024	10,760	(2,264)	83%	23%
PFE	Pfizer Inc.	Pharmaceuticals	12	590	14,436	10,596	(3,840)	73%	10%
PRU	Prudential Financial, Inc.	Life and Health Insurance	12	(36)	9,198	10,533	1,335	115%	36%
PCG	PG & E Corp.	Multi-Utilities	12	164	12,071	10,250	(1,821)	85%	75%
WFC	Wells Fargo & Company	Diversified Banks	12	(10)	11,030	9,639	(1,391)	87%	8%
DE	Deere & Company	Const., Farm Mach. and Trucks	10	104	10,197	9,504	(693)	93%	34%
AA	Alcoa, Inc.	Aluminum	12	233	12,343	9,451	(2,892)	77%	95%
HPQ	Hewlett-Packard Company	Computer Hardware	10	(49)	10,902	9,427	(1,475)	86%	17%
PEP	Pepsico, Inc.	Soft Drinks	12	291	9,851	8,870	(981)	90%	10%
EXC	Exelon Corp.	Electric Utilities	12	324	12,524	8,859	(3,665)	71%	46%
X	United States Steel Corp.	Steel	12	220	10,630	8,655	(1,975)	81%	244%
CVX	Chevron Corp.	Integrated Oil and Gas	12	781	10,271	8,579	(1,692)	84%	5%
IP	International Paper Co.	Paper Products	12	231	9,824	8,344	(1,480)	85%	91%
BRK.A	Berkshire Hathaway Inc.	Property and Casualty Ins.	12	249	10,598	8,246	(2,352)	78%	6%
ED	Consolidated Edison Inc.	Multi-Utilities	12	453	10,307	7,721	(2,586)	75%	68%
ABT	Abbott Laboratories	Pharmaceuticals	12	278	8,606	7,451	(1,155)	87%	11%
MRK	Merck & Co. Inc.	Pharmaceuticals	12	289	8,400	7,200	(1,200)	86%	9%
LLY	Eli Lilly & Co.	Pharmaceuticals	12	184	8,115	6,983	(1,132)	86%	20%
SO	Southern Company	Electric Utilities	12	54	7,223	6,834	(389)	95%	22%
MET	MetLife, Inc.	Life and Health Insurance	12	340	7,719	6,488	(1,231)	84%	21%
GD	General Dynamics Corp.	Aerospace and Defense	12	166	9,238	6,250	(2,988)	68%	41%
KFT	Kraft Foods Inc.	Packaged Foods and Meats	12	322	6,703	5,800	(903)	87%	11%
BMY	Bristol-Myers Squibb Company	Pharmaceuticals	12	60	6,704	5,766	(938)	86%	15%
DIS	Walt Disney Co.	Movies and Entertainment	10	412	8,084	5,684	(2,400)	70%	12%
JCP	J. C. Penney Company, Inc.	Department Stores	1	255	4,710	5,251	541	111%	83%
AET	Aetna Inc.	Managed Healthcare	12	164	5,821	5,244	(577)	90%	42%
MO	Altria Group Inc.	Tobacco	12	154	6,439	5,218	(1,221)	81%	12%
D	Dominion Resources, Inc.	Multi-Utilities	12	20	4,490	5,106	616	114%	17%
RAI	Reynolds American Inc.	Tobacco	12	114	5,529	4,934	(595)	89%	28%
DUK	Duke Energy Corporation	Electric Utilities	12	46	5,028	4,797	(231)	95%	21%
WY	Weyerhaeuser Co.	Specialized REITs	12	(47)	5,267	4,773	(494)	91%	57%
ALL	The Allstate Corporation.	Property and Casualty Ins.	12	297	5,545	4,669	(876)	84%	42%
KMB	Kimberly-Clark Corporation	Household Products	12	133	5,658	4,600	(1,058)	81%	22%
TXT	Textron Inc.	Industrial Conglomerates	1	126	5,877	4,559	(1,318)	78%	121%
FE	FirstEnergy Corp.	Electric Utilities	12	252	5,858	4,544	(1,314)	78%	34%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	117	6,173	4,320	(1,853)	70%	44%
ITT	ITT Corporation	Aerospace and Defense	12	70	5,364	4,272	(1,092)	80%	62%
SLE	Sara Lee Corp.	Packaged Foods and Meats	7	115	4,727	4,197	(530)	89%	45%
PPG	PPG Industries Inc.	Diversified Chemicals	12	161	4,952	4,127	(825)	83%	41%
KO	The Coca-Cola Company	Soft Drinks	12	170	4,837	4,118	(719)	85%	3%
SHLD	Sears Holdings Corporation	Department Stores	1	120	5,623	4,054	(1,569)	72%	81%

Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 7: Lowest GAAP funded ratio

Low funded ratios may place upward pressure on cash contribution requirements in future years

Sorted by GAAP funded % (lowest)
Note: only plans with obligations => $500 million and GAAP funded ratio < 75%
$ amounts in millions
US plans only
All pension data as of 2010

Ticker	Company Name	Industry	Month of Fiscal Year end	Pension Expense/ (Income)	US Plans Obligation	US Plans Assets	GAAP Funded Status	GAAP Funded %	PBO as a Percentage of Market Capitalization (as of 8/8/11)
MAS	Masco Corporation	Building Products	12	32	1,031	509	(522)	49%	35%
TSO	Tesoro Corporation	Oil and Gas Refining and Mkt.	12	65	564	294	(270)	52%	20%
AON	Aon Corporation	Insurance Brokers	12	30	2,376	1,244	(1,132)	52%	16%
MRO	Marathon Oil Corporation	Integrated Oil and Gas	12	217	3,221	1,798	(1,423)	56%	18%
DVN	Devon Energy Corporation	Oil and Gas Expl. and Prod.	12	85	1,124	632	(492)	56%	4%
VIA.B	Viacom, Inc.	Movies and Entertainment	9	31	807	464	(343)	57%	3%
MAT	Mattel Inc.	Leisure Products	12	32	546	317	(229)	58%	7%
APC	Anadarko Petroleum Corporation	Oil and Gas Expl. and Prod.	12	141	1,882	1,104	(778)	59%	6%
STT	State Street Corp.	Asset Mgmt. and Cust. Banks	12	23	1,070	630	(440)	59%	6%
PH	Parker Hannifin Corporation	Industrial Machinery	12	152	3,431	2,020	(1,411)	59%	32%
CLX	Clorox Corporation	Household Products	6	17	560	335	(225)	60%	6%
BF.B	Brown-Forman Corporation	Distillers and Vintners	4	13	577	351	(226)	61%	6%
WHR	Whirlpool Corp.	Household Appliances	12	40	3,605	2,288	(1,317)	63%	79%
ETN	Eaton Corporation	Industrial Machinery	12	108	2,458	1,572	(886)	64%	18%
AVP	Avon Products Inc.	Personal Products	12	49	703	452	(251)	64%	8%
CVS	CVS Caremark Corporation	Drug Retail	12	36	659	426	(233)	65%	1%
COL	Rockwell Collins Inc.	Aerospace and Defense	9	26	3,354	2,169	(1,185)	65%	45%
SNA	Snap-on Inc.	Industrial Machinery	1	34	1,037	675	(363)	65%	36%
NWL	Newell Rubbermaid Inc.	Housewares and Specialties	12	10	970	635	(335)	65%	27%
LSI	LSI Corporation	Semiconductors	12	2	1,310	858	(452)	66%	33%
GT	Goodyear Tire & Rubber Co.	Tires and Rubber	12	219	5,641	3,714	(1,927)	66%	186%
JEC	Jacobs Engineering Group Inc.	Construction and Engineering	10	42	1,167	770	(398)	66%	27%
MCK	McKesson Corporation	Healthcare Distributors	3	40	593	391	(202)	66%	3%
LLL	L-3 Communications Holdings Inc.	Aerospace and Defense	12	154	2,365	1,585	(780)	67%	33%
CI	CIGNA Corporation	Managed Healthcare	12	17	4,691	3,163	(1,528)	67%	40%
GD	General Dynamics Corp.	Aerospace and Defense	12	166	9,238	6,250	(2,988)	68%	41%
AES	The AES Corporation	Indp. Power Prods. and Ergy. Trds.	12	25	642	438	(204)	68%	8%
S	Sprint Nextel Corp.	Wireless Teleco. Svcs.	12	NA	1,900	1,300	(600)	68%	19%
CMS	CMS Energy Corp.	Multi-Utilities	12	114	2,014	1,401	(613)	70%	44%
FCX	Freeport-McMoRan Copper & Gold Inc.	Diversified Metals and Mining	12	42	1,598	1,112	(486)	70%	4%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	117	6,173	4,320	(1,853)	70%	44%
AKS	AK Steel Holding Corporation	Steel	12	23	3,529	2,473	(1,056)	70%	379%
NU	Northeast Utilities	Electric Utilities	12	85	2,821	1,978	(843)	70%	50%
COP	ConocoPhillips	Integrated Oil and Gas	12	442	5,539	3,890	(1,649)	70%	6%
DIS	Walt Disney Co.	Movies and Entertainment	10	412	8,084	5,684	(2,400)	70%	12%
PPL	PPL Corporation	Electric Utilities	12	68	4,007	2,819	(1,188)	70%	26%
CL	Colgate-Palmolive Co.	Household Products	12	94	1,952	1,377	(575)	71%	5%
APD	Air Products & Chemicals Inc.	Industrial Gases	9	51	2,446	1,727	(719)	71%	14%
TYC	Tyco International Ltd.	Industrial Conglomerates	9	34	930	657	(273)	71%	5%
EXC	Exelon Corp.	Electric Utilities	12	324	12,524	8,859	(3,665)	71%	46%
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	1,442	35,773	25,345	(10,428)	71%	150%
MON	Monsanto Co.	Fertilizers and Agr. Chemicals	8	74	1,950	1,383	(567)	71%	5%
AIZ	Assurant Inc.	Multi-line Insurance	12	45	749	534	(215)	71%	24%
CLF	Cliffs Natural Resources Inc.	Steel	12	46	1,022	734	(288)	72%	9%
SHLD	Sears Holdings Corporation	Department Stores	1	120	5,623	4,054	(1,569)	72%	81%
XOM	Exxon Mobil Corporation	Integrated Oil and Gas	12	1,388	15,007	10,835	(4,172)	72%	4%
PGN	Progress Energy Inc.	Electric Utilities	12	88	2,609	1,891	(718)	72%	20%
AVY	Avery Dennison Corporation	Office Services and Supplies	12	37	745	540	(205)	73%	26%
RDC	Rowan Companies Inc.	Oil and Gas Drilling	12	27	581	422	(159)	73%	14%
EMN	Eastman Chemical Co.	Diversified Chemicals	12	52	1,621	1,178	(443)	73%	28%
KEY	KeyCorp	Regional Banks	12	0	1,250	914	(336)	73%	19%
XRX	Xerox Corp.	Office Electronics	12	232	4,431	3,240	(1,191)	73%	39%
SWY	Safeway Inc.	Food Retail	1	113	2,257	1,652	(605)	73%	35%
PFG	Principal Financial Group Inc.	Life and Health Insurance	12	110	1,934	1,418	(516)	73%	26%
PFE	Pfizer Inc.	Pharmaceuticals	12	590	14,436	10,596	(3,840)	73%	10%
CBS	CBS Corporation	Broadcasting	12	144	4,982	3,660	(1,321)	73%	30%
NYX	NYSE Euronext, Inc.	Specialized Finance	12	9	856	630	(226)	74%	12%
SWK	Stanley Black & Decker, Inc.	Household Appliances	1	30	1,391	1,032	(358)	74%	14%
MKC	McCormick & Co. Inc.	Packaged Foods and Meats	11	22	516	383	(132)	74%	9%
CSX	CSX Corp.	Railroads	12	54	2,487	1,851	(636)	74%	10%

Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 8: Largest dollar amount of GAAP underfunding

These deficits have likely grown, possibly dramatically so, over the past few weeks

Sorted by GAAP funded $ (lowest)
$ amounts in millions
All plans with underfunding > $900 million
US plans only
All pension data as of 2010

					US Plans				
Ticker	Company Name	Industry	Month of Fiscal Year end	Pension Expense/ (Income)	Obligation	Assets	GAAP Funded Status	GAAP Funded %	PBO as a Percentage of Market Capitalization (as of 8/8/11)
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	1,442	35,773	25,345	(10,428)	71%	150%
BA	Boeing Co.	Aerospace and Defense	12	1,367	59,106	49,252	(9,854)	83%	128%
T	AT&T, Inc.	Integrated Telec. Services	12	2,536	56,187	47,621	(8,566)	85%	33%
GE	General Electric Co.	Industrial Conglomerates	12	1,072	51,999	44,801	(7,198)	86%	31%
F	Ford Motor Co.	Automobile Manufacturers	12	122	46,647	39,960	(6,687)	86%	113%
DD	EI DuPont de Nemours & Co.	Diversified Chemicals	12	557	23,924	18,403	(5,521)	77%	55%
DOW	The Dow Chemical Company	Diversified Chemicals	12	502	21,158	15,851	(5,307)	75%	61%
XOM	Exxon Mobil Corporation	Integrated Oil and Gas	12	1,388	15,007	10,835	(4,172)	72%	4%
RTN	Raytheon Co.	Aerospace and Defense	12	894	18,407	14,502	(3,905)	79%	126%
PFE	Pfizer Inc.	Pharmaceuticals	12	590	14,436	10,596	(3,840)	73%	10%
EXC	Exelon Corp.	Electric Utilities	12	324	12,524	8,859	(3,665)	71%	46%
VZ	Verizon Communications Inc.	Integrated Telec. Services	12	(83)	29,217	25,814	(3,403)	88%	30%
GD	General Dynamics Corp.	Aerospace and Defense	12	166	9,238	6,250	(2,988)	68%	41%
AA	Alcoa, Inc.	Aluminum	12	233	12,343	9,451	(2,892)	77%	95%
HON	Honeywell International Inc.	Aerospace and Defense	12	301	14,990	12,181	(2,809)	81%	41%
ED	Consolidated Edison Inc.	Multi-Utilities	12	453	10,307	7,721	(2,586)	75%	68%
DIS	Walt Disney Co.	Movies and Entertainment	10	412	8,084	5,684	(2,400)	70%	12%
BRK.A	Berkshire Hathaway Inc.	Property and Casualty Ins.	12	249	10,598	8,246	(2,352)	78%	6%
CAT	Caterpillar Inc.	Const., Farm Mach. and Trucks	12	527	13,024	10,760	(2,264)	83%	23%
UTX	United Technologies Corp.	Aerospace and Defense	12	218	24,445	22,384	(2,061)	92%	38%
NOC	Northrop Grumman Corporation	Aerospace and Defense	12	595	25,263	23,265	(1,998)	92%	171%
X	United States Steel Corp.	Steel	12	220	10,630	8,655	(1,975)	81%	244%
GT	Goodyear Tire & Rubber Co.	Tires and Rubber	12	219	5,641	3,714	(1,927)	66%	186%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	117	6,173	4,320	(1,853)	70%	44%
PCG	PG & E Corp.	Multi-Utilities	12	164	12,071	10,250	(1,821)	85%	75%
CVX	Chevron Corp.	Integrated Oil and Gas	12	781	10,271	8,579	(1,692)	84%	5%
COP	ConocoPhillips	Integrated Oil and Gas	12	442	5,539	3,890	(1,649)	70%	6%
SHLD	Sears Holdings Corporation	Department Stores	1	120	5,623	4,054	(1,569)	72%	81%
JNJ	Johnson & Johnson	Pharmaceuticals	12	583	14,993	13,433	(1,560)	90%	9%
CI	CIGNA Corporation	Managed Healthcare	12	17	4,691	3,163	(1,528)	67%	40%
IP	International Paper Co.	Paper Products	12	231	9,824	8,344	(1,480)	85%	91%
HPQ	Hewlett-Packard Company	Computer Hardware	10	(49)	10,902	9,427	(1,475)	86%	17%
MRO	Marathon Oil Corporation	Integrated Oil and Gas	12	217	3,221	1,798	(1,423)	56%	18%
PH	Parker Hannifin Corporation	Industrial Machinery	12	152	3,431	2,020	(1,411)	59%	32%
WFC	Wells Fargo & Company	Diversified Banks	12	(10)	11,030	9,639	(1,391)	87%	8%
CBS	CBS Corporation	Broadcasting	12	144	4,982	3,660	(1,321)	73%	30%
TXT	Textron Inc.	Industrial Conglomerates	1	126	5,877	4,559	(1,318)	78%	121%
WHR	Whirlpool Corp.	Household Appliances	12	40	3,605	2,288	(1,317)	63%	79%
FE	FirstEnergy Corp.	Electric Utilities	12	252	5,858	4,544	(1,314)	78%	34%
UPS	United Parcel Service, Inc.	Air Freight and Logistics	12	573	21,342	20,092	(1,250)	94%	34%
MET	MetLife, Inc.	Life and Health Insurance	12	340	7,719	6,488	(1,231)	84%	21%
MO	Altria Group Inc.	Tobacco	12	154	6,439	5,218	(1,221)	81%	12%
MRK	Merck & Co. Inc.	Pharmaceuticals	12	289	8,400	7,200	(1,200)	86%	9%
XRX	Xerox Corp.	Office Electronics	12	232	4,431	3,240	(1,191)	73%	39%
PPL	PPL Corporation	Electric Utilities	12	68	4,007	2,819	(1,188)	70%	26%
COL	Rockwell Collins Inc.	Aerospace and Defense	9	26	3,354	2,169	(1,185)	65%	45%
ABT	Abbott Laboratories	Pharmaceuticals	12	278	8,606	7,451	(1,155)	87%	11%
LLY	Eli Lilly & Co.	Pharmaceuticals	12	184	8,115	6,983	(1,132)	86%	20%
AON	Aon Corporation	Insurance Brokers	12	30	2,376	1,244	(1,132)	52%	16%
ITT	ITT Corporation	Aerospace and Defense	12	70	5,364	4,272	(1,092)	80%	62%
ETR	Entergy Corporation	Electric Utilities	12	147	4,301	3,216	(1,085)	75%	40%
KMB	Kimberly-Clark Corporation	Household Products	12	133	5,658	4,600	(1,058)	81%	22%
AKS	AK Steel Holding Corporation	Steel	12	23	3,529	2,473	(1,056)	70%	379%
IBM	International Business Machines Corp.	IT Consulting and Other Svcs.	12	(935)	51,293	50,259	(1,034)	98%	25%
PEP	Pepsico, Inc.	Soft Drinks	12	291	9,851	8,870	(981)	90%	10%
AEP	American Electric Power Co., Inc.	Electric Utilities	12	141	4,807	3,858	(949)	80%	28%
BMY	Bristol-Myers Squibb Company	Pharmaceuticals	12	60	6,704	5,766	(938)	86%	15%
FDX	FedEx Corporation	Air Freight and Logistics	5	308	13,983	13,055	(928)	93%	55%
M	Macy's, Inc.	Department Stores	1	144	3,712	2,804	(908)	76%	34%
KFT	Kraft Foods Inc.	Packaged Foods and Meats	12	322	6,703	5,800	(903)	87%	11%

Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 9: Largest unrecognized losses as of the end of 2010

These losses have likely ballooned year-to-date given asset price and interest rate moves

Sorted by largest unrecognized losses $
$ amounts in millions
All companies with unrecognized losses > $1.5 billion
US plans only
All pension data as of 2010

Ticker	Company Name	Industry	Month of Fiscal Yearend	Unrecognized Losses at the end of 2010	Unrecognized Losses as a Percentage of Market Capitalization (as of 8/8/11)
BA	Boeing Co.	Aerospace and Defense	12	19,343	44%
GE	General Electric Co.	Industrial Conglomerates	12	18,603	11%
IBM	International Business Machines Corp.	IT Consulting and Other Svcs.	12	15,865	8%
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	12,263	53%
DD	EI DuPont de Nemours & Co.	Diversified Chemicals	12	9,032	22%
RTN	Raytheon Co.	Aerospace and Defense	12	7,794	56%
UTX	United Technologies Corp.	Aerospace and Defense	12	7,223	11%
UPS	United Parcel Service, Inc.	Air Freight and Logistics	12	6,833	11%
DOW	The Dow Chemical Company	Diversified Chemicals	12	6,696	21%
F	Ford Motor Co.	Automobile Manufacturers	12	6,567	17%
BAC	Bank of America Corporation	Other Diversified Financial Svcs.	12	6,117	9%
FDX	FedEx Corporation	Air Freight and Logistics	5	5,157	21%
XOM	Exxon Mobil Corporation	Integrated Oil and Gas	12	5,028	1%
CAT	Caterpillar Inc.	Const., Farm Mach. and Trucks	12	4,795	9%
NOC	Northrop Grumman Corporation	Aerospace and Defense	12	4,246	30%
AA	Alcoa, Inc.	Aluminum	12	4,221	35%
X	United States Steel Corp.	Steel	12	4,197	101%
EXC	Exelon Corp.	Electric Utilities	12	4,129	16%
C	Citigroup, Inc.	Other Diversified Financial Svcs.	12	4,021	5%
MMM	3M Co.	Industrial Conglomerates	12	3,981	7%
CVX	Chevron Corp.	Integrated Oil and Gas	12	3,919	2%
ED	Consolidated Edison Inc.	Multi-Utilities	12	3,915	27%
LLY	Eli Lilly & Co.	Pharmaceuticals	12	3,797	9%
GD	General Dynamics Corp.	Aerospace and Defense	12	3,778	17%
DE	Deere & Company	Const., Farm Mach. and Trucks	10	3,774	13%
KFT	Kraft Foods Inc.	Packaged Foods and Meats	12	3,658	6%
JNJ	Johnson & Johnson	Pharmaceuticals	12	3,539	2%
IP	International Paper Co.	Paper Products	12	3,412	34%
PFE	Pfizer Inc.	Pharmaceuticals	12	3,224	2%
BMY	Bristol-Myers Squibb Company	Pharmaceuticals	12	3,150	7%
ABT	Abbott Laboratories	Pharmaceuticals	12	2,879	4%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	2,810	21%
DIS	Walt Disney Co.	Movies and Entertainment	10	2,788	4%
PEP	Pepsico, Inc.	Soft Drinks	12	2,726	3%
JPM	JPMorgan Chase & Co.	Other Diversified Financial Svcs.	12	2,627	2%
FE	FirstEnergy Corp.	Electric Utilities	12	2,554	16%
AET	Aetna Inc.	Managed Healthcare	12	2,380	18%
GT	Goodyear Tire & Rubber Co.	Tires and Rubber	12	2,314	82%
ALL	The Allstate Corporation	Property and Casualty Ins.	12	2,311	18%
MO	Altria Group Inc.	Tobacco	12	2,287	4%
RAI	Reynolds American Inc.	Tobacco	12	2,151	11%
AEP	American Electric Power Co., Inc.	Electric Utilities	12	2,129	13%
MET	MetLife, Inc.	Life and Health Insurance	12	2,092	6%
ITT	ITT Corporation	Aerospace and Defense	12	1,986	23%
TXT	Textron Inc.	Industrial Conglomerates	1	1,977	44%
COL	Rockwell Collins Inc.	Aerospace and Defense	9	1,949	27%
PPG	PPG Industries Inc.	Diversified Chemicals	12	1,911	17%
XRX	Xerox Corp.	Office Electronics	12	1,867	17%
HIG	Hartford Financial Services Group Inc.	Multi-line Insurance	12	1,852	24%
MRK	Merck & Co. Inc.	Pharmaceuticals	12	1,837	2%
BAX	Baxter International Inc.	Healthcare Equipment	12	1,805	6%
CI	CIGNA Corporation	Managed Healthcare	12	1,805	17%
WFC	Wells Fargo & Company	Diversified Banks	12	1,785	1%
D	Dominion Resources, Inc.	Multi-Utilities	12	1,773	7%
PCG	PG & E Corp.	Multi-Utilities	12	1,755	11%
JCP	J. C. Penney Company, Inc.	Department Stores	1	1,601	29%
BK	The Bank of New York Mellon Corp.	Asset Mgmt. and Cust. Banks	12	1,582	6%
COP	ConocoPhillips	Integrated Oil and Gas	12	1,567	2%
PEG	Public Service Enterprise Group Inc.	Multi-Utilities	12	1,562	11%
XEL	Xcel Energy Inc.	Multi-Utilities	12	1,503	14%

Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 10: Highest % of unrecognized losses to market capitalization
%s have risen for most companies during 2011

Sorted by largest unrecognized losses as a % of Market Cap
$ amounts in millions
All companies with unrecognized losses > 10% of market cap
US plans only
All pension data as of 2010

Ticker	Company Name	Industry	Month of Fiscal Yearend	Unrecognized Losses at the end of 2010	Unrecognized Losses as a Percentage of Market Capitalization (as of 8/8/11)
X	United States Steel Corp.	Steel	12	4,197	101%
GT	Goodyear Tire & Rubber Co.	Tires and Rubber	12	2,314	82%
RTN	Raytheon Co.	Aerospace and Defense	12	7,794	56%
LMT	Lockheed Martin Corporation	Aerospace and Defense	12	12,263	53%
SVU	SUPERVALU Inc.	Food Retail	2	702	49%
GCI	Gannett Co., Inc.	Publishing	12	1,170	48%
BA	Boeing Co.	Aerospace and Defense	12	19,343	44%
TXT	Textron Inc.	Industrial Conglomerates	1	1,977	44%
OI	Owens-Illinois, Inc.	Metal and Glass Containers	12	1,232	42%
RRD	R.R. Donnelley & Sons Company	Commercial Printing	12	1,069	40%
AKS	AK Steel Holding Corporation	Steel	12	337	39%
AA	Alcoa, Inc.	Aluminum	12	4,221	35%
IP	International Paper Co.	Paper Products	12	3,412	34%
R	Ryder System, Inc.	Trucking	12	658	30%
NOC	Northrop Grumman Corporation	Aerospace and Defense	12	4,246	30%
JCP	J. C. Penney Company, Inc.	Department Stores	1	1,601	29%
WHR	Whirlpool Corp.	Household Appliances	12	1,255	28%
COL	Rockwell Collins Inc.	Aerospace and Defense	9	1,949	27%
ED	Consolidated Edison Inc.	Multi-Utilities	12	3,915	27%
HIG	Hartford Financial Services Group Inc.	Multi-line Insurance	12	1,852	24%
ITT	ITT Corporation	Aerospace and Defense	12	1,986	23%
DD	EI DuPont de Nemours & Co.	Diversified Chemicals	12	9,032	22%
FDX	FedEx Corporation	Air Freight and Logistics	5	5,157	21%
DOW	The Dow Chemical Company	Diversified Chemicals	12	6,696	21%
MSI	Motorola Solutions, Inc.	Communications Equipment	12	2,810	21%
PBI	Pitney Bowes Inc.	Office Services and Supplies	12	720	19%
AET	Aetna Inc.	Managed Healthcare	12	2,380	18%
ALL	The Allstate Corporation	Property and Casualty Ins.	12	2,311	18%
F	Ford Motor Co.	Automobile Manufacturers	12	6,567	17%
XRX	Xerox Corp.	Office Electronics	12	1,867	17%
GD	General Dynamics Corp.	Aerospace and Defense	12	3,778	17%
NI	NiSource Inc.	Multi-Utilities	12	871	17%
PPG	PPG Industries Inc.	Diversified Chemicals	12	1,911	17%
CI	CIGNA Corporation	Managed Healthcare	12	1,805	17%
NWL	Newell Rubbermaid Inc.	Housewares and Specialties	12	577	16%
EXC	Exelon Corp.	Electric Utilities	12	4,129	16%
FE	FirstEnergy Corp.	Electric Utilities	12	2,554	16%
LXK	Lexmark International Inc.	Computer Storage and Perips.	12	370	15%
CSC	Computer Sciences Corporation	Data Proc. and Outsourced Svcs.	4	729	15%
FHN	First Horizon National Corp.	Regional Banks	12	289	15%
PH	Parker Hannifin Corporation	Industrial Machinery	12	1,496	15%
EMN	Eastman Chemical Co.	Diversified Chemicals	12	780	14%
WY	Weyerhaeuser Co.	Specialized REITs	12	1,258	14%
XEL	Xcel Energy Inc.	Multi-Utilities	12	1,503	14%
DE	Deere & Company	Const., Farm Mach. and Trucks	10	3,774	13%
AEP	American Electric Power Co., Inc.	Electric Utilities	12	2,129	13%
GR	Goodrich Corp.	Aerospace and Defense	12	1,308	13%
CPB	Campbell Soup Co.	Packaged Foods and Meats	8	1,263	13%
AVY	Avery Dennison Corporation	Office Services and Supplies	12	355	13%
SHLD	Sears Holdings Corporation	Department Stores	1	783	12%
MAS	Masco Corporation	Building Products	12	357	12%
M	Macy's, Inc.	Department Stores	1	1,229	12%
IR	Ingersoll-Rand Plc	Industrial Machinery	12	1,121	11%
SLE	Sara Lee Corp.	Packaged Foods and Meats	7	1,143	11%
UTX	United Technologies Corp.	Aerospace and Defense	12	7,223	11%
GE	General Electric Co.	Industrial Conglomerates	12	18,603	11%
RAI	Reynolds American Inc.	Tobacco	12	2,151	11%
UPS	United Parcel Service, Inc.	Air Freight and Logistics	12	6,833	11%
CMA	Comerica Incorporated	Diversified Banks	12	583	11%
PCG	PG & E Corp.	Multi-Utilities	12	1,755	11%
CEG	Constellation Energy Group, Inc.	Indp. Power Prods. and Ergy. Trds.	12	741	11%
PEG	Public Service Enterprise Group Inc.	Multi-Utilities	12	1,562	11%
SUN	Sunoco, Inc.	Oil and Gas Refining and Mkt.	12	389	11%

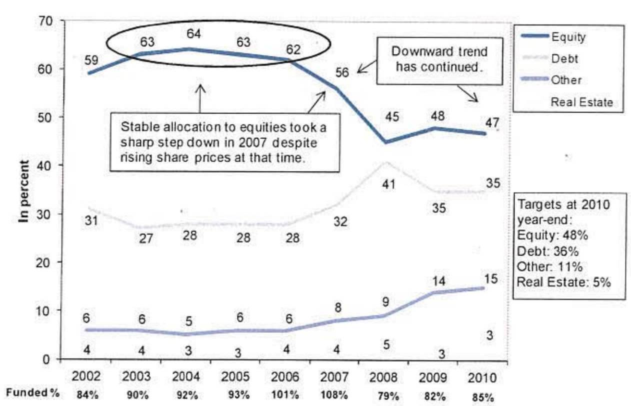
Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Public plans facing some of the same challenges

Public plans have more equity exposure than corporate plans.

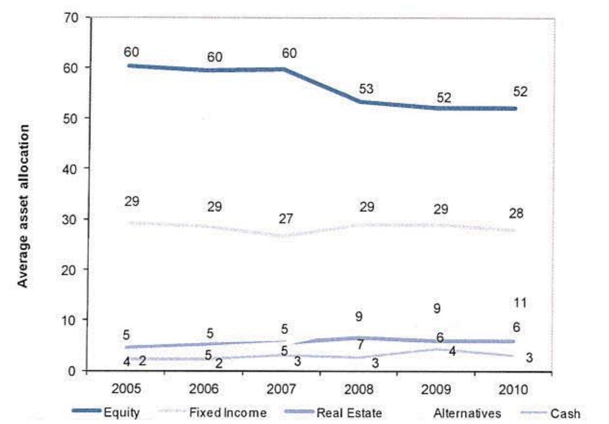
Public DB pension plans are feeling some of the same stresses as their corporate brethren. In particular, the downward move in equity prices has likely impacted them even more than corporate plans given their higher allocations to equities. Indeed, in 2010 public plans had 52% of assets in equities versus 47% for corporate DB plans (see Exhibits 11 and 12). Public plans often have higher equity exposures because: (1) they are less well-funded than corporate plans and therefore need assets than will generate relatively higher returns; and (2) the weak finances of many state and local governments have been hindering contribution activity, again leading to a need to have higher allocations to return generating assets to help make up underfunded balances.

Exhibit 11: Some corporate plans have de-risked
Allocation to equity has declined notably



Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports.

Exhibit 12: Public plans have higher allocations to equity
May feel the decline in equity prices more than corporate DB



Source: National Association of State Retirement Administrators Public Fund Survey.

Average discount rates in 2010: Corporate DB, 5.4% Public DB, 8.0%

However, there are important computational differences in the way public plans and corporate plans calculate and report funded status. For example, public plans do not use high-quality long-term interest rates as the benchmark for setting their discount rates. Rather, public plans use their expected return on plan assets assumption as the discount rate.[4] Not only is this rate higher than that used by corporate plans, but as it is not tied to market interest rates, public plans should not see the upward move in pension liabilities that corporate plans are feeling due to the decline in interest rates as discussed earlier in this report.

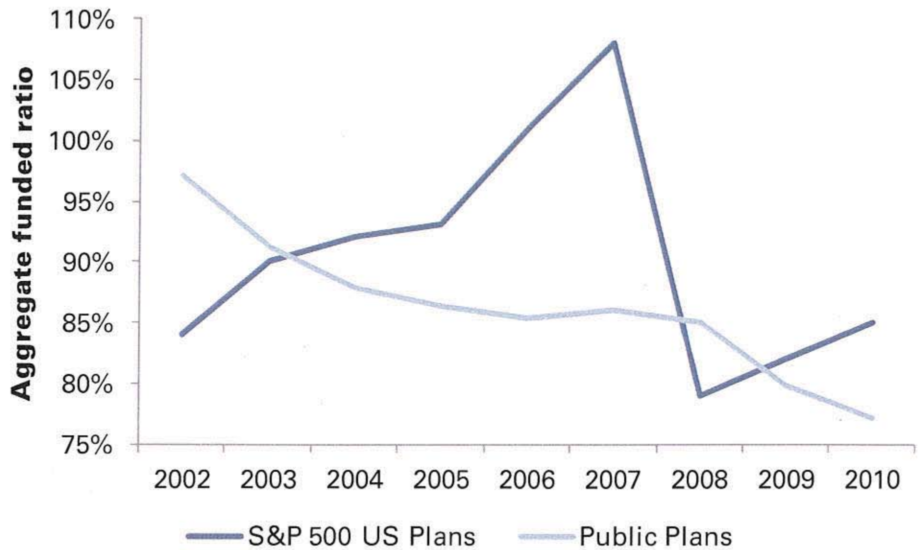
In addition, public plans use actuarial smoothed values of plan assets when calculating funded status. The most common smoothing time period is five years, but some plans use even longer periods. While this has the effect of reducing year-to-year volatility in funded status ratios, it also means that it can take longer for reported funded ratios to adjust to rising or falling asset values.

Consider, for example, the reported funded ratios of corporate DB plans in the S&P 500 versus those of public plans as detailed in Exhibit 13. The reported corporate funded ratios, which use the fair market value for assets and which adjust liabilities each year to account for market interest rates, are much more volatile than the reported public funded ratios

[4] In June 2011 the Governmental Accounting Standards Board proposed changes to this accounting which could result in the used of a blended rate, for some plans, comprised of the expected return assumption and the rate on a municipal bond index. However, no final decision on whether to adopt this proposal is imminent.

which use smoothed asset values and which do not see the discount rate fluctuate much year to year (if at all).

Exhibit 13: Reported public plan funded ratios will likely continue to fall
Actual plan asset losses from 2008 still being factored into some public plan ratios



Source: Goldman Sachs Global Markets Institute; Capital IQ; Company reports; National Association of State Retirement Administrators Public Fund Survey.

Note, however, that from 2002 through 2006 the reported funded ratios of public plans declined 12 percentage points, despite rising equity prices during this period, while corporate plans reported a funded status increase of 17 percentage points. Similarly, while corporate DB funded ratios improved from 2008 through 2010, public funded ratios fell, partly due to the ongoing smoothing of plan asset losses incurred during 2008.

Much of this is due to the aforementioned smoothing of asset values. Consequently, while the smoothing may limit any downward adjustment to public plan funded ratios in the near term that may result from the recent weakness in equity prices, **the slow adjustment to funded ratios from any losses in 2011, combined with the continued smoothing of losses from 2008, will likely lead to a continual drop in reported public DB funded ratios over the next few years.**

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