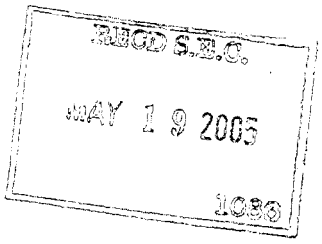
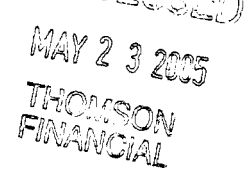


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INVESTING IN OUR REGION'S FUTURE

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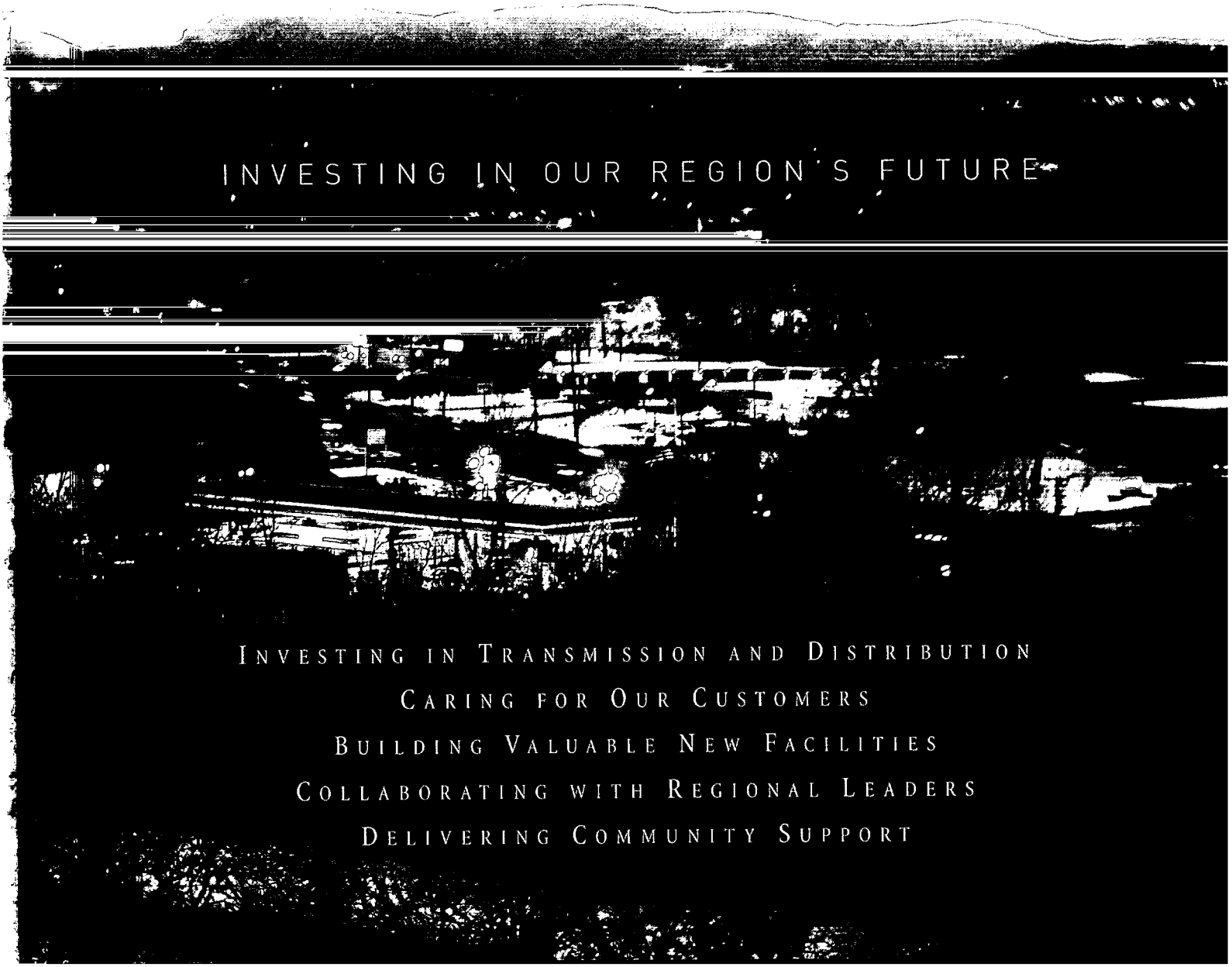
Company Profile

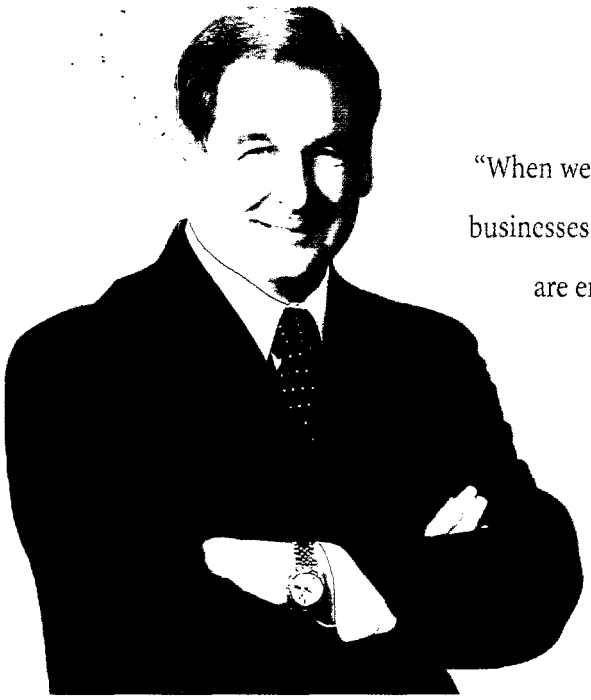
Northeast Utilities (NYSE: NU) is a Fortune 500 diversified energy company located in Connecticut with operations throughout the Northeast. Through our regulated and competitive subsidiaries, NU provides Energy for a Changing World, with a full range of energy products and services to millions of residential and business customers. NU is committed to safety, reliability and expanding consumers' energy options. For more information on Northeast Utilities and our subsidiaries, visit the NU family of Web sites at www.nu.com.



Financial Highlights

(Thousands of dollars, except share information and statistical data)	2004	2003	% Change
Operating Revenues	**$6,686,699**	$6,069,156	10%
Operating Income	**$ 412,952**	$ 424,236	(3)%
Net Income	**$ 116,588**	$ 116,411	—%
Fully Diluted Earnings per Common Share	**$ 0.91**	$ 0.91	—%
Fully Diluted Common Shares Outstanding (Weighted Average)	**128,396,076**	127,240,724	1%
Dividends per Share	**$ 0.63**	$ 0.58	9%
Sales of Electricity (Regulated Retail, kWh-millions)	**36,198**	35,866	1%
Electric Customers (Average)	**1,865,334**	1,829,876	2%
Gas Customers (Average)	**194,212**	192,816	1%
Property, Plant and Equipment, Net	**$5,864,161**	$5,429,916	8%





"When we combine expectations for our competitive generation and retail businesses with the anticipated performance of our regulated platform, we are energized by our plans and ability to enhance shareholder value."

Charles W. Shivery
Chairman, President
and CEO

To Our Shareholders, Employees, Customers and Business Partners

2004 was a year of mixed results for Northeast Utilities. On the regulated side of our business, results were very positive and earnings grew $23.1 million. This reflects our commitment to our regulated growth strategy and significant energy infrastructure investments for our region's future. Unfortunately, our competitive businesses had a disappointing year. Overall, they lost $15.1 million in 2004, significantly lowering NU's overall earnings from the level we had targeted. We are taking a number of steps to address these unacceptable results.

After a comprehensive review of our competitive energy businesses early in 2005, we made the decision that NU Enterprises, Inc. (NUEI), the holding company for NU's competitive energy investments, will exit the wholesale marketing business. Our evaluation determined that the wholesale marketing business will be unable to attain the profit margins necessary to generate acceptable returns and cash flows.

We also determined that NUEI's competitive energy services businesses are not central to NU's long-term strategy and do not meet our expectations of profitability. We are exploring ways to divest those businesses in a manner that maximizes their value. The services businesses include electrical, mechanical, telecommunications, commercial plumbing and performance contracting companies.

Our decision reflects a thorough examination of our competitive businesses and the market, as well as the impact on our valued employees. While difficult, it is clearly the right business decision for Northeast Utilities — now, and for the future.

We will retain NUEI's generation and retail energy marketing businesses. We believe that the generation assets and retail business are competitively positioned to create significant opportunities over the next several years.



Building value for shareholders

When we combine expectations for our competitive generation and retail businesses with the anticipated performance of our regulated platform, we are energized by our plans and ability to enhance shareholder value.

We remain stewards of a healthy balance sheet with ready access to capital to execute our growth strategy. That strategy will serve three purposes: deliver results and value to shareholders, minimize corporate risk and meet the reliability needs of our customers.

Consistent with our strategy, in 2004 we:

- Increased our dividend for the fourth consecutive year, with our rate of increases above average in the utility industry.
- Grew regulated business earnings by $23.1 million or 17 percent.
- Resolved a number of regulatory issues, providing the company with more ratemaking certainty than we have had in several years..
- Stepped into the future with world-class technological advances in transmission line engineering.
- Held steadfast to the ethics and values fundamental to our business.

For the year, NU earned $116.6 million, or 91 cents per share, compared with $116.4 million, or 91 cents per share, in 2003. While this earnings level is steady from 2003, it falls far short of our original $1.30 per share target. Nonetheless, consistent with our dividend policy, we increased the quarterly dividend 8 percent in 2004, the fourth consecutive year of above-average growth. During that time the quarterly dividend has risen 62.5 percent, from 10 cents per share to 16.25 cents per share.

Staying the course with our regulated businesses to serve customers

For more than a century, NU's regulated businesses have been an integral part of the region, demonstrating the highest commitment to serving our customers. In our second century, we continue to honor that commitment.

Our core, regulated businesses delivered powerful performance with earnings growth that surpassed the previous year. PSNH, WMECO and Yankee Gas reached rate case settlements in 2004, and CL&P concluded a fully litigated outcome at the end of 2003. Needed rate increases position us to invest considerable capital to enhance reliability for customers and to continue growing the company.

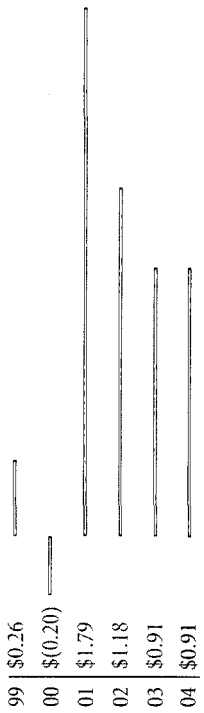
Over the next five years, our regulated companies plan to invest approximately $3.7 billion in electric and natural gas infrastructure improvements to meet customer needs. The bulk of these investments will be in transmission, with substantial investments also being made at each of our regulated subsidiaries.

The transmission system is overburdened in certain areas of our region, with a critical electricity bottleneck in southwest Connecticut where demand has outpaced supply. We are addressing this with plans to invest more than $1.5 billion over the next five years in transmission infrastructure improvements, which are aligned with federal policy direction promoting expansion to ensure reliability.

The 345-kV Bethel to Norwalk, Connecticut, transmission upgrade project has broken ground and is expected to be in service by December 2006. Along with United Illuminating, we have also applied to build a second 345-kV transmission upgrade between Middletown and Norwalk, Connecticut, with completion expected in 2009. This project reflects advanced engineering plans to bury 24 miles of the 69-mile line, while fully maintaining system reliability. The underground portion is the most ambitious project of its type in North America and puts us at the very leading edge of technology.

Further, we are enhancing the distribution system that delivers electricity and natural gas to neighborhoods, businesses and industry. At CL&P alone, a $900 million, four-year upgrade and expansion of the distribution system is under way.

EARNINGS PER COMMON SHARE
(DOLLARS)



In New Hampshire, PSNH's Northern Wood Power Project has begun the $75 million conversion of a Portsmouth coal-fired generating unit to burn wood chips. The plant brings significant environmental benefits and a $20 million boost to the state's wood industry and economy. As Bill Dunlap, chairman of the Society for the Protection of New Hampshire Forests, noted at the groundbreaking for this project, "One of our missions is to preserve a sustainable forestry industry. The Northern Wood Power Project is right in line with that mission and good for the environment. It's a home run."

On the gas side of our business, Yankee Gas broke ground early in 2005 to construct a $108 million liquefied natural gas (LNG) storage facility in Waterbury, Connecticut. The LNG project has been a model of collaboration and partnerships, bringing together government, business, regulators and the Waterbury community. The new facility is expected to deliver both supply and price benefits to our customers and is the largest construction project in Yankee's history.

Our investment in the region carries us well beyond poles, wires and pipes. Northeast Utilities companies are basic building blocks of the economic climate, quality of life and overall well-being of the cities, towns and customers we serve. For us, doing well in business also means doing good, by enriching our communities and making life better for those who count on us.

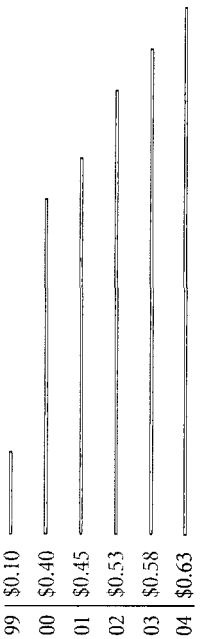
Supporting the United Way campaign is just one of the ways our employees make a positive difference. In 2004, including matching corporate contributions and NU Foundation donations, the NU team pledged more than $1.7 million to United Way and Combined Health Appeal charities to help people across New England.

In 2004, the NU Foundation awarded a substantial grant to extend our environmental stewardship. Our $500,000 grant to The Nature Conservancy initiates a large-scale, multi-state commitment to improve the long-term viability of the Connecticut River, from the Canadian border to Long Island Sound. The Connecticut River program will enhance conservation of New England's most important waterway.

Changing course with our competitive businesses

Poor performance in major areas of our competitive business in 2004 necessitated a change in course. The wholesale group lost $17 million last year, compared with a loss of $3.7 million in 2003. Despite the hard work and dedication of employees in this business, NUEI's wholesale marketing business is not expected to attain adequate profit margins given the wholesale merchant energy environment. As a result, we will exit the wholesale marketing business.

DIVIDENDS PER SHARE
(DOLLARS)



Our competitive energy services businesses lost $2.3 million in 2004. We have concluded that these businesses are not central to NU's long-term strategy and do not meet the company's expectations of profitability. We are exploring ways to divest of them in a way that maximizes shareholder value.

Despite these areas of disappointment, there were some bright spots at NUEI, with two segments of our competitive businesses performing well.

Select Energy's retail energy business earned $4.9 million in 2004. We enjoy a very strong retail energy marketing franchise in the Northeast and mid-Atlantic states, and we expect to build on that market presence. Consequently, we will retain and grow this business. Select Energy's retail group currently serves some 30,000 commercial and industrial customer locations in the New England, New York and PJM power pools.

Likewise, our competitive generating assets continue to perform well, and we will retain them. The 1,443 megawatts are primarily pumped storage, hydroelectric and coal-fired units, all of which are competitive in today's environment. They have solid operating histories, and we expect their value could increase significantly in the coming years. In addition, we will retain our Northeast Generation Services subsidiary to operate our generating plants.

Taking Northeast Utilities into the future

As we move into the future, our brand and reputation serve us well in both our regulated businesses and the competitive businesses we are retaining. That reputation is upheld every day by the men and women who work here and the values they demonstrate. At NU, caring for our customers and delivering value to shareholders are at the core of who we are and how we operate.

Setting the course for NU is our ambitious regulated growth plan with investments unparalleled in New England. The focus of these investments for the next several years will continue to be on improving the electricity and natural gas delivery systems of our franchised service territories in Connecticut, Massachusetts and New Hampshire. These upgrades will require several billion dollars to maintain and improve an infrastructure that is central to the economic vitality and quality of life in New England. We have the financial strength to make the investments on behalf of our customers and investors, and we intend to complete them with the support of our regulators.

Focused now on retail marketing and generation assets, our competitive businesses see substantial opportunity for growth. The number of commercial and industrial customers buying electricity and natural gas from competitive suppliers is continuing to rise, positioning NUEI's Select Energy for an expanded market presence. We project revenues to grow to approximately $1 billion in 2005 because of continued expansion of the retail market and our high retention rate of approximately 85 percent. Further, the market for generating capacity is improving in New England, and owning generation will help us maintain a strong retail marketing presence in the region.

To achieve our goals and position us for the future, we realigned our senior management team at the start of 2005. Lee Olivier, formerly CL&P president, assumed the new position of president — Transmission Group. Lee brings his broad management experience to this organization as we put in place the transmission infrastructure that is so critical to our region and our customers.

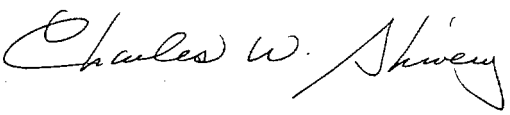
Ray Necci, formerly vice president-Utility Group Services, was promoted to president of CL&P to replace Lee; Rod Powell was promoted to president of WMECO; and Larry De Simone assumed the role of president of the Competitive Group, replacing Bill Schivley who retired as president of Select Energy.

At the end of 2004 we also bid farewell to John Forsgren, vice chairman, executive vice president and chief financial officer. John was a key force behind our strategic and financial achievements, and we wish him well in his retirement.

Reflecting on 2004 accomplishments, I would like to thank our Board of Trustees for their support and for sharing their experience and guidance. I also want to thank NU shareholders for your continued confidence in us. We are ever mindful and appreciative of your investment. To our customers, very simply, thank you for your business.

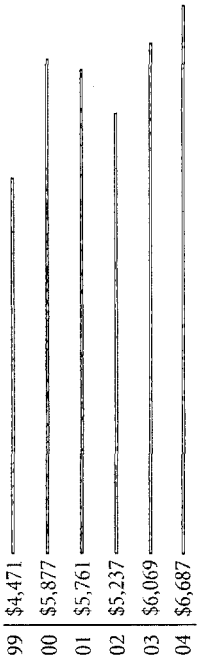
I extend a special heartfelt "thank you" to our employees and retirees for their talent, dedication and commitment to the success of our company. The men and women who work here are the true energy behind Northeast Utilities, now and for our region's future.

Sincerely,



Charles W. Shivery
Chairman, President and Chief Executive Officer

REVENUES
(DOLLARS IN MILLIONS)









Investing wisely in

Transmission and Distribution



Our core transmission and distribution business keeps the economy moving and reflects our long-standing service obligation. In 2004, we diligently demonstrated the value of an infrastructure investment plan that will benefit customers in meeting their electricity load growth and service reliability needs, along with providing earnings growth.

Much of New England's energy infrastructure is aging, and we have a unique opportunity to improve it. Our regulated infrastructure investment plan calls for capital expenditures of $3.7 billion through 2009. The transmission upgrade portion of the plan includes an investment of more than $1.5 billion over the next five years. On the distribution side, we expect to spend $900 million on a four-year upgrade and expansion at CL&P, along with substantial investments in each of our regulated subsidiaries.

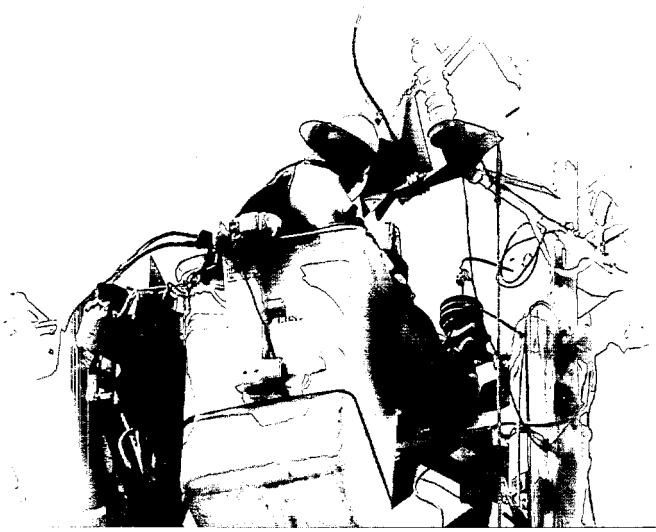
Expanding needed energy infrastructure

Southwest Connecticut Transmission: We are building reliability for the region, with urgent needs in southwest Connecticut where electricity growth outpaces the rest of the state.

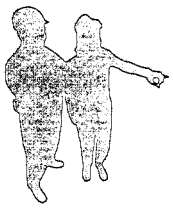
In June 2004, CL&P's substation upgrade in Stamford was placed on line. In March 2005, CL&P broke ground on the 345-kV transmission upgrade from Bethel to Norwalk with a completion date of December 2006. CL&P, along with United Illuminating, has also applied to build a 345-kV transmission upgrade from Middletown to Norwalk, with completion expected in 2009. In addition, we have sought approval to construct two 115-kV understreet lines between Stamford and Norwalk, with an estimated in-service date of 2008. Moving from land to sea, we are working to replace an undersea electric transmission line between Norwalk and Northport, Long Island, New York. We expect the cable to be in service by mid-2008.

Transmission lines like these in central Connecticut are part of New England's bulk power backbone connecting generating plants to lower voltage distribution lines that deliver electricity to customers.

Safely and reliably, our lineworkers maintain the lines and facilities that serve customers.



Caring for Our Customers



Fundamental to our business is strong operational performance with power flowing safely and reliably to our customers. Through improved cost management, optimum work practices and enhanced efficiencies, we are continuously improving operations to provide exceptional care for our customers.

Electric reliability is critical to those who depend on computers and sophisticated electronic equipment both at work and at home. Key among our initiatives in 2004 was CL&P's consolidation of three Regional Operations Centers into a state-of-the-art System Operations Center in Berlin, Connecticut. Among other enhancements, the new center features "smart" technology for the efficient monitoring and operation of the electric system. This move represents a major step in our efforts to more effectively manage assets, enhance safety and improve service reliability for our customers.

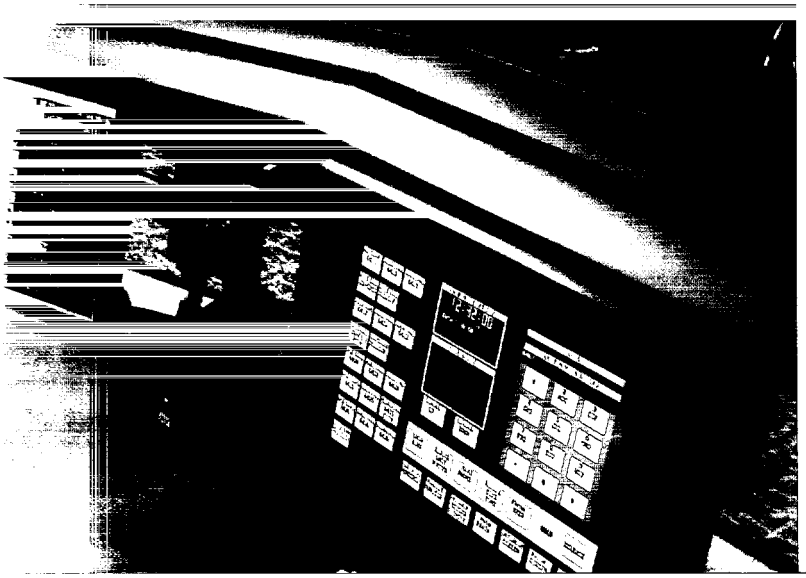
Similarly, we have undertaken a four-year project to integrate and support the customer service needs of all four of our regulated companies — CL&P, PSNH, WMECO and Yankee Gas. By consolidating six call centers into two, integrating Customer Service and Information Technology support, and implementing one customer information system across these businesses, we save money while further enhancing customer service and business efficiency.





Our customers, big and small, enjoy safe and dependable service from Northeast Utilities companies.





Designed to better meet our customers' increasing expectations and improve reliability, our new state-of-the-art System Operations Center enables more efficient monitoring and operation of the electric system. Using new "smart" technology, operators have more information available to analyze trouble spots, remotely de-energize selected lines and, during outages, switch customers to other circuits to restore service faster.



Building

Valuable New Facilities



At Northeast Utilities, our look to the future reflects a broad, inclusive perspective on new initiatives. We choose investments and projects that deliver substantial benefit to a wide variety of audiences including customers, local businesses, municipalities and the environment.

In 2004, Yankee Gas received regulatory approval to move ahead with construction of a $108 million liquefied natural gas (LNG) storage and production facility in Waterbury, Connecticut — the largest construction project in the company's history. Site preparation work was well under way during 2004, paving the way for construction of the facility to begin in early 2005. The new plant will give Yankee the flexibility to buy natural gas in periods of low demand, store it as a liquid and use it to meet customer needs during peak demand periods. This long-term energy solution will keep prices stable for customers and benefits Waterbury by providing additional significant tax revenue to support the city's economic recovery and vitality. The plant is expected to be in service for the 2007/2008 heating season.

Offering both significant environmental advantages and a $20 million boost to New Hampshire's wood industry and economy, PSNH is investing $75 million to replace a coal-fired boiler with a state-of-the-art 50 MW boiler to burn wood at Schiller Station in Portsmouth. The Northern Wood Power Project will allow PSNH to economically produce cleaner electric energy from renewable resources — wood chips and other clean, low-grade wood materials. The project is one of the largest renewable energy projects in the country, with completion expected in late 2006.

Atop Schiller Station, Marc Lefebvre (left), station electrician, and Jeff Edwards, station electrical working foreman, review specifications for the Northern Wood Power Project conversion from coal to a state-of-the-art boiler that burns wood chips.

Staff engineer Eric Anderson (right) reviews plans to retire the north propane tank farm in Waterbury, Connecticut, with pressure management mechanic George Lynch. Retiring the propane plant is a requirement for Yankee Gas' LNG project.



Collaborating with

Regional Leaders



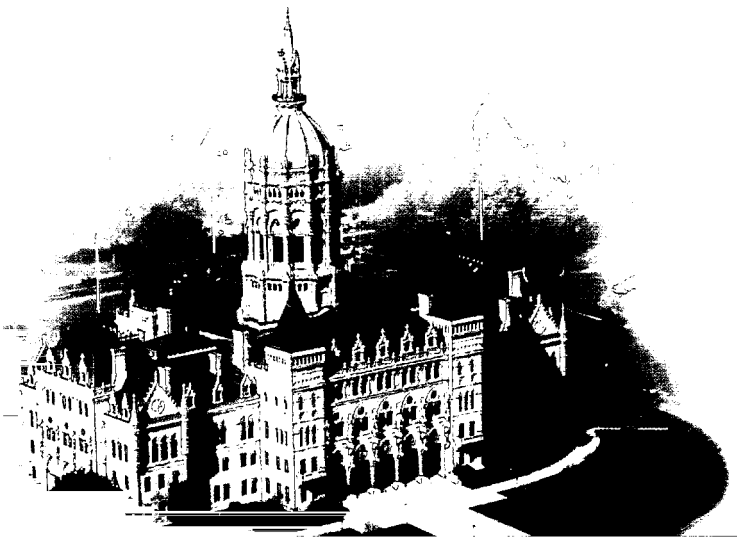
Supporting our communities and working with regional leaders is central to how we conduct business. In 2004, we made a major investment in downtown Springfield by moving our WMECO headquarters to Springfield Technical Community College's Technology Park at a time when the city was facing a financial crisis. Ensuring Western Massachusetts' urban centers continued stability is vital to a successful economic climate and enhanced quality of life, and we are proud to demonstrate our commitment to the region now and for the future.

Our ambitious economic development outreach stepped up in 2004 with the launch of the Northeast Utilities-led "Discover New England for Business" program. This joint effort of six New England states puts our region front and center with companies and the consultants who advise them on where best to locate new offices and factories. NU's initiative burnishes New England's image nationwide and overseas to attract investments and jobs.

In downtown Hartford, Connecticut, at the Kinsella Elementary School, we are helping students succeed in a unique way that may develop new leaders for our region. A $500,000 NU Foundation grant has enabled development of a valuable enrichment program called PEAC — Parental Involvement, Etiquette Enrichment, Academic Enrichment and Character Development. The program, a partnership with the Hartford school system, the city and Southend Community Services, includes NU employees mentoring PEAC students. It is just one of countless examples of a long tradition of building partnerships to help our communities and our region.

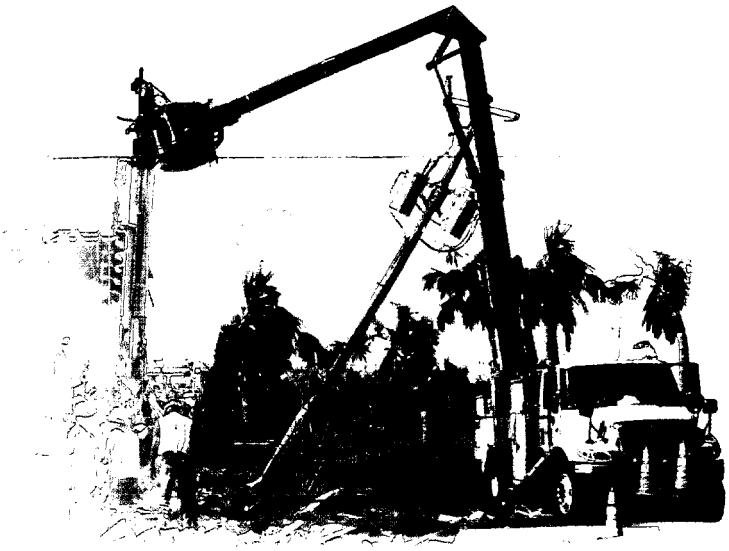
Working together, these business partners brought WMECO's headquarters to downtown Springfield's Technology Park to enhance one of New England's turnaround urban centers.

(Left to right) Brian Corridan, chairman of the STCC Assistance Corp. (owners and operators of Technology Park); Rod Powell, president and chief operating officer, WMECO; Representative Benjamin Swan; Paul Tangredi, director, Business Development, WMECO; Nancy Creed, manager, WMECO Communications.





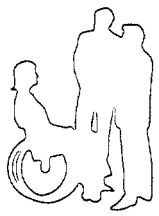
NU line crews and trucks provided critical help restoring power to Florida areas devastated by last fall's hurricanes. NU leads the way in mutual aid storm support, both providing and receiving help when nature delivers damaging storms and large scale outages.



Each year, we reach out to fifth grade students across our service area to teach valuable lessons in electrical safety. CL&P lead lineman Lambert Givens instructs students how to be safe around electricity. Students from left are Kelsey Socha, Spencer Higgins and Haley Jones.



Delivering Heartfelt Community Support



For more than 100 years, NU has been woven into the fabric of our communities. From businesses to the elderly to parents and students, tens of thousands of people directly benefit from our programs and services each year.

A near 15-year partnership between CL&P and the Special Olympics Connecticut Winter Games brings together company employee and retiree volunteers to support hundreds of competing athletes from across Connecticut. CL&P welcomes the two-day cross-country skiing and snowshoeing competitions to our Simsbury Service Center, with volunteers making snow, managing the event and cheering on the competitors. The event is truly special, both for the determined, inspirational athletes and for our many volunteers.

And NU does not stop at caring for communities in our service area. In the fall of 2004, 225 NU workers performed extraordinary power restoration work to help Florida recover from three devastating hurricanes. Crews numbering 21 from CL&P, 16 from PSNH and nine from WMECO safely worked in dangerous conditions, stifling heat, humidity and rain to help residents and businesses in communities overwhelmed with destruction and loss. We received hundreds of appreciative phone calls and letters from Florida residents and businesses thanking us for rushing 1,200 miles to their assistance.



Our Regulated and Competitive Businesses

REGULATED BUSINESSES

Company	Business
The Connecticut Light and Power Company (CL&P)	Largest electric utility in Connecticut, delivering energy to nearly 1.2 million residential and commercial customers in 149 cities and towns. **www.cl-p.com**
Public Service Company of New Hampshire (PSNH)	Largest electric utility in New Hampshire, serving more than 475,000 homes and businesses in 211 communities. Generates electricity using a diverse fuel mix at 12 facilities. **www.psnh.com**
Western Massachusetts Electric Company (WMECO)	Largest electric utility serving the western portion of Massachusetts, delivering energy to some 200,000 customers throughout 59 communities. **www.wmeco.com**
Yankee Energy System, Inc. (YES)	Yankee Gas Services Company, the regulated subsidiary of YES, is Connecticut's largest natural gas distribution company serving 194,000 customers in 71 communities. **www.yankeeenergy.com**
Transmission Group	New England's leading high-voltage electric transmission provider, serving nearly five million customers. **www.transmission-nu.com**

COMPETITIVE BUSINESSES

Beginning in 2005, our Competitive Business focus will be in two areas:	**Retail energy marketing, with Select Energy** supplying electricity and natural gas to more than 30,000 commercial and industrial customer locations in the New England, New York and mid-Atlantic regional energy markets.
	Competitive generation, with 1,443 megawatts of pumped storage, hydroelectric and coal-fired plants owned by our Northeast Generation Company (NGC) and Holyoke Water Power Company (HWP) subsidiaries. Northeast Generation Services subsidiary manages and operates these power generation facilities. **www.selectenergy.com**

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Financial Condition and Business Analysis

Executive Summary

The following items in this executive summary are explained in more detail in this annual report.

Results and Outlook:

- Northeast Utilities (NU or the company) reported earnings of $116.6 million in 2004 compared with earnings of $116.4 million in 2003 and $152.1 million in 2002.
- After the payment of preferred dividends, earnings at the Utility Group increased by $23.1 million to $155.6 million, or $1.21 per share, in 2004 compared with $132.5 million, or $1.04 per share, in 2003.
- Included in 2004 earnings is an after-tax loss of $48.3 million associated with mark-to-market accounting for certain natural gas positions established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. Results in 2004 also include after-tax investment write-downs totaling $8.8 million, primarily associated with NU's investments in a fuel cell development company and a telecommunications company.
- Results in 2003 included a $36.9 million after-tax loss associated with the implementation of Standard Market Design (SMD) in Connecticut and a negative cumulative effect of an accounting change of $4.7 million from the adoption of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities."
- On March 9, 2005, NU completed its previously announced comprehensive review of its competitive energy businesses and decided that NU Enterprises will exit the wholesale marketing business. NU also concluded that NU Enterprises' energy services businesses are not central to NU's long-term strategy and do not meet the company's expectations of profitability. As a result, the company will explore ways to divest those businesses in a manner that maximizes their value. NU will retain its competitive generation and retail energy marketing businesses, because it believes that the generation assets and retail business are competitively positioned to create significant opportunities for those businesses over the next several years.
- The Utility Group estimates that it will earn between $1.22 per share and $1.30 per share in 2005. Parent and other costs, primarily related to interest expense, are estimated to total between $0.08 per share and $0.13 per share in 2005. Because of the variety of methods the company could use to implement its decisions concerning the wholesale marketing and energy services businesses, NU will not provide a 2005 earnings range for its NU Enterprises businesses or for NU consolidated.

Regulatory Items:

NU resolved a number of outstanding regulatory issues, providing the company with more ratemaking certainty than it has had in a number of years. Among the most important items were:

Transmission:

- On August 19, 2004, a Connecticut Superior Court dismissed the City of Norwalk's appeal of the Connecticut Siting Council's (CSC) approval of a 345 kilovolt (kV) transmission line between Bethel, Connecticut and Norwalk, Connecticut.
- On September 16, 2004, the Federal Energy Regulatory Commission (FERC) approved a settlement agreement with the states of Connecticut, New Hampshire and Massachusetts that allowed the transmission business to implement a formula rate with an 11.0 percent return on equity (ROE).

CL&P:

- On June 28, 2004, the FERC approved a settlement agreement to resolve the dispute over the implementation of SMD in Connecticut. Under the settlement, The Connecticut Light and Power Company (CL&P) returned to its customers and suppliers, including affiliate Select Energy, Inc. (Select Energy), approximately $158 million of revenues collected from customers in 2003 and early 2004.
- The Connecticut Department of Public Utility Control (DPUC) issued a final decision on August 4, 2004 on CL&P's petition for reconsideration of the DPUC's December 2003 rate order. The decision had a positive earnings impact of $6.9 million in 2004.
- On August 1, 2003, CL&P filed with the DPUC to establish transitional standard offer (TSO) rates equal to December 31, 1996 total rate levels. On December 19, 2003, the DPUC issued a final decision setting the average TSO rate at $0.1076 per kilowatt-hour (kWh) effective January 1, 2004.
- As a result of higher supply charges, higher federally mandated congestion charges (FMCC) and a $25.1 million distribution rate increase approved by the DPUC in CL&P's rate case, on November 24, 2004, CL&P requested the DPUC to increase its TSO rate for 2005. On December 22, 2004, the DPUC approved a 10.4 percent rate increase effective January 1, 2005 and allowed for the recovery of the remainder of the requested increase through existing and new refunds and overrecoveries.
- On February 1, 2005, CL&P filed an application with the DPUC to obtain approval to defer for future recovery in its retail transmission rate the increased transmission costs that CL&P is incurring as of February 1, 2005.
- On February 1, 2005, CL&P filed for approval for a 1.6 percent increase to TSO rates ($29.2 million) to collect additional FMCC from customers effective May 1, 2005. The increase is necessary to collect costs related to an additional Reliability Must Run (RMR) contract related to two generating plants located in southwest Connecticut. The RMR contract has preliminary approval for billing from the FERC and is subject to a future review by the FERC prior to final approval.

Yankee Gas:

- On September 3, 2004, the DPUC approved the application of Yankee Gas Services Company (Yankee Gas) to construct a liquefied natural gas (LNG) storage facility in Waterbury, Connecticut capable of storing 1.2 billion cubic feet of natural gas with an estimated cost of $108 million.
- The DPUC approved the Yankee Gas rate case settlement agreement on December 8, 2004. The approval resulted in a $14 million increase in rates beginning January 1, 2005.

PSNH:

- In October 2004, Public Service Company of New Hampshire (PSNH) received the approvals necessary to begin construction related to the conversion of one of three 50-megawatt units at the coal-fired Schiller Station to burn wood.
- On September 2, 2004, the New Hampshire Public Utilities Commission (NHPUC) approved the negotiated settlement of the PSNH rate case that was filed in 2003. The settlement agreement resulted in an annualized delivery rate increase of $3.5 million beginning October 1, 2004 and approval of another rate increase of $10 million on June 1, 2005.
- On September 24, 2004, PSNH filed a petition with the NHPUC requesting a change in the transition energy service rate for residential and small commercial customers and the default energy service rate (TS/DS) for large commercial and industrial customers for the period February 1, 2005 through January 31, 2006. PSNH files for updated TS/DS rates periodically to ensure timely recovery of its costs. The NHPUC issued its order approving PSNH's proposed TS/DS rate of $0.0649 per kWh on January 28, 2005.

WMECO:

- On December 29, 2004, the Massachusetts Department of Telecommunications and Energy (DTE) approved a settlement agreement to increase Western Massachusetts Electric Company's (WMECO) electricity distribution rates by $6 million annually effective January 1, 2005 and by an additional $3 million annually beginning January 1, 2006. The settlement also reduced WMECO's transition charge by approximately $13 million annually.

Liquidity:

- During 2004, the Utility Group issued a total of $505 million of fixed-rate bonds and notes with maturities ranging from 10 years to 30 years. The debt was issued primarily to fund capital expenditure programs, repay higher cost debt and fund prior spent nuclear fuel obligations.
- NU's capital expenditures, totaled $643.8 million in 2004, compared with $563.6 million in 2003 and $510.5 million in 2002. The increase resulted from increased spending on new electric transmission projects. NU projects capital expenditures of approximately $740 million in 2005.
- NU's net cash flows from operations totaled $517.1 million in 2004, compared with $593.4 million in 2003 and $615.8 million in 2002.

Overview

Consolidated: NU reported 2004 earnings of $116.6 million, or $0.91 per share, compared with earnings of $116.4 million, or $0.91 per share, in 2003 and $152.1 million or $1.18 per share in 2002. All earnings per share amounts are reported on a fully diluted basis.

Earnings in 2004 of $116.6 million, or $0.91 per share, include an after-tax loss of $48.3 million, or $0.38 per share, associated with mark-to-market accounting for certain natural gas positions established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England. Also included in 2004 earnings are after-tax investment write-downs of approximately $8.8 million ($13.8 million on a pre-tax basis), or $0.07 per share, primarily related to NU's investments in a fuel cell development company and a telecommunications company. NU's 2004 earnings were essentially unchanged from 2003. Utility Group earnings increased by $23.1 million due to increased rates and other positive regulatory developments. That increase was offset by increased losses at NU Enterprises and higher parent and other costs. Increased NU Enterprises losses were due primarily to a 2004 negative mark-to-market loss on certain natural gas contracts. Higher parent and other costs were due to higher investment write-downs in 2004.

NU's 2003 earnings of $116.4 million or $0.91 per share include a charge of $36.9 million, or $0.29 per share, associated with a loss recorded for the settlement of a wholesale power contract dispute between CL&P and its three 2003 standard offer power suppliers, including an NU subsidiary, Select Energy. Also included in 2003 earnings was a negative $4.7 million after-tax cumulative effect of an accounting change as a result of the adoption of FIN 46. 2003 earnings decreased by $35.7 million compared to 2002. Earnings at the Utility Group decreased significantly in 2003 due to lower pension income and the absence of earnings related to the Seabrook nuclear unit (Seabrook). These decreases were partially offset by lower Utility Group controllable operation and maintenance costs. NU's 2003 results benefited from lower corporate-wide interest costs and improved performance at NU Enterprises from improved margins on Select Energy's energy supply contracts, higher volumes, improved operation of NU Enterprises' generating facilities, and the absence of natural gas trading losses that occurred in the first half of 2002.

A summary of NU's earnings/(losses) by major business line for 2004, 2003 and 2002 is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2004	2003	2002
Utility Group	**$155.6**	$132.5	$198.3
NU Enterprises	**(15.1)**	(3.4)	(53.2)
Parent and Other	**(23.9)**	(12.7)	7.0
Net Income	**$116.6**	$116.4	$152.1

NU's revenues during 2004 increased to $6.7 billion from $6.1 billion in 2003 and from $5.2 billion in 2002. The increase in 2004 revenues was due to increased revenues from NU Enterprises totaling $0.4 billion primarily as a result of higher merchant energy retail sales volumes and higher prices. The remainder of the increase in 2004 revenues related to higher Utility Group transmission and distribution revenues as a result of higher rates and higher FMCC revenues.

The increase in 2003 revenues was due to increased revenues from NU Enterprises totaling $0.6 billion as a result of higher wholesale and retail sales volumes and higher prices. The remainder of the increase in 2003 revenues was due to increases in electric sales at the Utility Group in 2003 as compared to 2002.

Utility Group: The Utility Group is comprised of CL&P, PSNH, WMECO, and Yankee Gas, including their transmission, distribution and generation businesses. After the payment of preferred dividends, earnings at the Utility Group increased by $23.1 million to $155.6 million, or $1.21 per share, in 2004 compared with $132.5 million, or $1.04 per share, in 2003. Earnings at the Utility Group were $198.3 million in 2002. The increase in Utility Group earnings during 2004 was primarily due to increases in CL&P's retail rates. CL&P's earnings increased in 2004 compared to 2003 by approximately $12 million due to amounts disallowed in the December 2003 rate case decision and subsequently allowed in the reconsideration decision. Those improvements were partially offset by lower pension income and higher interest and depreciation expense. A summary of Utility Group earnings by company for 2004, 2003 and 2002 is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2004	2003	2002
CL&P*	**$ 82.5**	$ 63.4	$ 80.1
PSNH	**46.6**	45.6	62.9
WMECO	**12.4**	16.2	37.7
Yankee Gas	**14.1**	7.3	17.6
Net Income	**$155.6**	$132.5	$198.3

* After preferred dividends.

CL&P earned $82.5 million in 2004 after preferred dividends of $5.6 million, compared with $63.4 million in 2003 after preferred dividends of $5.6 million. CL&P's improved earnings resulted primarily from a retail rate increase that took effect January 1, 2004. These higher retail rates were offset by higher operating expenses, lower pension income and a higher effective tax rate. CL&P also benefited from the final decision on the reconsideration of CL&P's rate case, which had a positive after-tax impact of $6.9 million in 2004. In 2003, after-tax write-offs of approximately $5 million were recorded based on the DPUC's December 2003 rate case order. The higher effective tax rate was due to higher reversal of prior flow-through depreciation and other adjustments to tax expense totaling a negative $3.2 million recorded in the third quarter of 2004 as opposed to a positive $5.5 million recorded in 2003.

PSNH earned $46.6 million in 2004, compared with $45.6 million in 2003. PSNH earnings were higher primarily due to a lower effective tax rate and an increase in retail sales of 3.1 percent. The lower effective tax rate and increase in sales were largely offset by higher operating expenses and higher pension expense. The lower effective tax rate was due to other adjustments to tax expense totaling a positive $5.4 million recorded in the third quarter of 2004.

WMECO earned $12.4 million in 2004, compared with $16.2 million in 2003. WMECO's 2004 earnings were lower due to lower pension income and higher interest and depreciation expense, offset by a 1.6 percent increase in retail sales.

Yankee Gas earned $14.1 million in 2004, compared with $7.3 million in 2003. Yankee Gas' 2004 results benefited from the absence of a negative $6.2 million adjustment to the estimate of unbilled revenues in 2003 and a lower effective tax rate. The lower effective tax rate was due to other adjustments to tax expense totaling a positive $4.3 million recorded in the second and third quarters of 2004.

Included in Utility Group company earnings are the results of the transmission business. Transmission business earnings were $29.5 million in 2004 as compared to $28.2 million in 2003. Transmission business earnings in 2004 are higher than 2003 primarily due to higher revenues resulting from the implementation of a FERC approved formula rate resulting in increased rates and $123 million of transmission projects that were placed in service. This forward-looking formula rate allows NU to place capital investments in rates immediately upon being placed in service. The formula rate took effect on October 28, 2003.

NU Enterprises: NU Enterprises, Inc. is the parent company of Northeast Generation Company (NGC), Northeast Generation Services Company (NGS), Select Energy, Select Energy Services, Inc. (SESI) and their respective subsidiaries, and Woods Network Services, Inc. (Woods Network), all of which are collectively referred to as "NU Enterprises." The generation operations of Holyoke Water Power Company (HWP) are also included in the results of NU Enterprises. The companies included in the NU Enterprises segment are grouped into two business segments: the merchant energy segment and the energy services business segment. The merchant energy business segment is comprised of Select Energy's wholesale marketing business, Select Energy's retail marketing business, and approximately 1,296 megawatts (MW) of pumped storage and hydroelectric generation assets owned by NGC and 147 MW of coal-fired generation assets owned by HWP. The energy services business consists of the operations of NGS, SESI and Woods Network.

On March 9, 2005, NU completed its previously announced comprehensive review of its competitive energy businesses and decided that NU Enterprises will exit the wholesale marketing business. NU also concluded that NU Enterprises' energy services businesses are not central to NU's long-term strategy and do not meet the company's expectations of profitability. As a result, the company will explore ways to divest those businesses in a manner that maximizes their value. NU will retain its competitive generation and retail energy marketing businesses, because it believes that the generation assets and retail business are competitively positioned to create significant opportunities for those businesses over the next several years.

NU Enterprises had a loss of $15.1 million in 2004, or $0.12 per share, compared with a loss of $3.4 million, or $0.03 per share in 2003, and a loss of $53.2 million, or $0.41 per share, in 2002.

NU Enterprises 2004 loss includes an after-tax loss of $48.3 million, or $0.38 per share, associated with mark-to-market accounting for certain natural gas positions established to mitigate the risk of electricity purchased in anticipation of winning certain levels of wholesale electric load in New England.

A summary of NU Enterprises' earnings/(losses) by business for 2004, 2003 and 2002 is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2004	2003	2002
Merchant Energy	**$(12.1)**	$(5.5)	$(52.4)
Energy Services, Parent and Other	**(3.0)**	2.1	(0.8)
Net Loss	**$(15.1)**	$(3.4)	$(53.2)

The mark-to-market loss on natural gas contracts was the primary reason for increased NU Enterprises losses in 2004. This loss was in the wholesale marketing portion of the merchant energy segment. However, merchant energy earnings benefited from improved results in the retail marketing portion of the merchant energy segment from increased commercial and industrial electric and natural gas sales. Retail marketing earned $4.9 million in 2004, compared to a loss of $1.8 million in 2003. Energy services earnings decreased by $4.9 million in 2004 from 2003 due primarily to losses on a construction contract.

Parent and Other: Losses unrelated to the Utility Group and NU Enterprises totaled $23.9 million in 2004, compared with a loss of $12.7 million in 2003 and income of $7 million in 2002. The higher losses in 2004 were mostly attributable to investment write-downs related to NU's investments in a fuel cell development company and a telecommunications company and due to higher interest expenses. The higher losses in 2003 were mostly attributable to the negative $4.7 million cumulative effect of an accounting change associated with the adoption of FIN 46 recorded in 2003 and to Seabrook related gains recorded in 2002.

Future Outlook

Utility Group: The Utility Group estimates that it will earn between $1.22 per share and $1.30 per share in 2005. That range reflects earnings of between $0.96 per share and $1.00 per share in the regulated distribution and generation business and between $0.26 per share and $0.30 per share in the transmission business.

NU Enterprises: The earnings of NU Enterprises will be impacted by many factors, including the amount of asset impairments or losses on disposals that could result from the decision to exit the wholesale marketing business and explore ways to divest the energy services segment, the mark-to-market loss that may result from the application of mark-to-market accounting to certain wholesale marketing contracts until those contracts are sold or until the commodities are delivered, and other closure costs. Accordingly, NU will not be providing NU Enterprises or NU consolidated 2005 earnings guidance.

Parent and Other: Parent and other costs, primarily related to interest expense, are estimated to total between $0.08 per share and $0.13 per share in 2005.

Strategic Overview

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

Based on current projections, NU expects that the need to invest heavily in regulated infrastructure to meet reliability requirements and customer growth will cause NU's Utility Group distribution and generation rate base to rise from $2.5 billion in 2004 to nearly $3.9 billion by the end of 2009. Based on currently projected expenditures and capital project completion dates, NU expects that the same factors will increase NU's Utility Group transmission rate base from approximately $460 million in 2004 to approximately $1.7 billion by the end of 2009.

NU Enterprises Business Review: On March 9, 2005, NU completed its previously announced comprehensive review of each of NU Enterprises' businesses, in which a full range of alternative strategies was considered. That review considered:

- The impact of the increase in competition in the New England wholesale energy markets over the last six months of 2004, which has affected Select Energy's profitability by reducing the number of bids won and by reducing the margins on the bids that are won;
- The potential growth of the retail business, which had a significant improvement in earnings in 2004 and which serves a market that NU believes to be growing;
- The competitiveness and opportunities for increased value for the 1,443 MW of generation currently owned by NU Enterprises;
- The strategic fit of the energy services businesses; and
- The impact of any significant changes on NU as a whole.

As a result of the comprehensive review, NU has decided that NU Enterprises will exit the wholesale marketing business. NU also concluded that NU Enterprises' energy services businesses are not central to NU's long-term strategy and do not meet the company's expectations of profitability. As a result, the company will explore ways to divest those businesses in a manner that maximizes their value. Those businesses include electrical, mechanical, telecommunications, commercial plumbing, and performance contracting companies. NU will retain its competitive generation and retail energy marketing businesses, because it believes that the generation assets and retail business are competitively positioned to create significant opportunities for those businesses over the next several years.

NU has concluded that the wholesale merchant energy sector in the power pools between Maine and Maryland is becoming increasingly competitive and that NU Enterprises' wholesale marketing business will be unable to attain the profit margins necessary to generate acceptable returns and cash flows. As a result, NU Enterprises will explore a number of alternatives for exiting the wholesale marketing business, including selling the wholesale franchise, selling existing contracts, restructuring longer term contracts, and allowing shorter-term contracts to expire without being renewed. In the interim, NU Enterprises will only bid on new full requirements wholesale contracts to improve the value of its book of business by reducing existing electric positions.

NU Enterprises' marketing subsidiary, Select Energy, has built a very strong retail energy marketing franchise in the Northeast and Middle Atlantic states, and the company expects to build on that market presence. Additionally, the number of commercial and industrial customers buying their electricity and natural gas from competitive suppliers is continuing to rise. Select Energy's retail marketing revenues in 2004 were approximately $850 million on sales of approximately 10 million megawatt-hours of electricity and 40 billion cubic feet of natural gas. Select Energy's retail marketing business serves approximately 30,000 commercial and industrial locations in the New England, New York and PJM power pools. Select Energy's retail marketing business projects revenues to grow to approximately $1 billion in 2005 because of a continued expansion of the retail market and its high customer retention rate of approximately 85 percent.

NU will retain its 1,443 MW of competitive generating assets because it expects that their value could increase significantly in the coming years. The competitive generating assets, which include pumped storage, hydroelectric, and coal-fired units, are contained within NGC and HWP subsidiaries. NU Enterprises also will retain its NGS subsidiary, which operates the NGC and HWP plants.

NU Enterprises accounted for approximately $2.1 billion of NU's revenue in 2004, excluding sales to affiliated regulated companies. The wholesale marketing business accounted for approximately $1 billion of that revenue, and NU Enterprises' energy services businesses accounted for approximately $275 million. The energy services businesses include E.S. Boulos Company and Woods Electrical Co., Inc., both electrical contractors; Woods Network, a telecommunications contracting firm; Select Energy Contracting, Inc., an electrical, mechanical, and plumbing contractor; and SESI, a performance contracting subsidiary that specializes in upgrading the energy efficiency of large governmental and institutional facilities.

NU expects to record a charge in the first quarter of 2005 associated with the wholesale marketing and energy services business. The level of that charge will depend on a number of factors, including how the disposition of those businesses is accomplished.

The company expects that implementation of its decisions will have an impact on employment levels in those businesses but that the actual impact is not known at this time because the disposition process has just begun. It is the company's goal to minimize layoffs by using, to the extent possible, open positions within NU or by a possible sale of both the wholesale marketing franchise and the energy services businesses in which the buyers may offer positions to existing employees.

Liquidity

Consolidated: NU continues to maintain an adequate level of liquidity. At December 31, 2004, NU had $47 million of cash and cash equivalents on hand compared with $43.4 million at December 31, 2003. As discussed in Note 16, "Restatement of Previously Issued Financial Statements," the December 31, 2003 amount of cash and cash equivalents has been restated.

Cash flows from operations decreased by $76.3 million from $593.4 million in 2003 to $517.1 million in 2004. Changes in current assets and liabilities were consistent from year to year and were decreases of approximately $91 million in 2003 and approximately $86 million in 2004. Increases in cash flows related to deferred taxes were offset by decreases related to regulatory refunds.

The decrease in year over year cash flows from regulatory (refunds)/overrecoveries is primarily due to lower Competitive Transition Assessment (CTA) and Generation Service Charge (GSC) collections in 2004 as CL&P refunds amounts to its ratepayers for past over collections or uses those amounts to recover current costs. These refunds are also the primary reason for the positive change in year over year deferred income taxes, which has increased operating cash flows as refunded amounts were currently deducted for tax purposes. Lower taxes paid also benefited cash flows from operations in 2004 due to bonus tax depreciation on newly completed plant assets.

NU paid common dividends of $80.2 million in 2004, compared with $73.1 million in 2003 and $67.8 million in 2002. The increase reflects increases in quarterly common dividends of $0.0125 per share declared in the third quarters of 2002, 2003, and 2004. Management expects to continue to recommend that the NU Board of Trustees increase the common dividend on an annual basis, subject to the company's future earnings and cash requirements. On January 31, 2005, the Board of Trustees approved a quarterly dividend of $0.1625 per share, payable March 31, 2005 to shareholders of record as of March 1, 2005.

Capital expenditures described herein are cash capital expenditures and exclude cost of removal, AFUDC, and the capitalized portion of pension income. NU's capital expenditures totaled $643.8 million in 2004, compared with $563.6 million in 2003 and $510.5 million in 2002. NU's 2004 capital expenditures included $370.8 million by CL&P, $143.6 million by PSNH, $56.6 million by Yankee Gas, $38.6 million by WMECO, and $34.2 million by other NU subsidiaries, including $17.6 million by NU Enterprises. The increase in capital expenditures was primarily the result of higher transmission capital expenditures, which totaled $163.9 million in 2004, compared with $96.3 million in 2003 and $57.9 million in 2002. The company projects capital expenditures of approximately $3.7 billion over the five-year period from 2005 through 2009, including approximately $740 million in 2005. Capital spending projections are highly dependent on regulatory approval of major projects, particularly transmission investments.

Management projects that NU will need in excess of $4 billion from 2005 through 2009 to meet its capital expenditure requirements, common and preferred dividends, and other cash requirements. NU expects to fund approximately half of this need through operating cash flows with the remainder expected to be funded through external financings and the sale of common shares. Management believes that the majority of the external financing will be debt but that NU will need to raise several hundred million dollars through the sale of its common shares. The timing and amount of those equity issuances will depend greatly on the timing of major transmission investments and the level of dividends and equity capital that will be paid to NU by its subsidiaries. Over the next five years, management expects the Utility Group to continue to issue debt annually while debt levels at NU parent and NGC continue to decline.

To maintain a capital structure that includes approximately 55 percent of total debt at each of the Utility Group companies, NU continues to infuse common equity. NU parent made a total of $94.5 million of common equity contributions to the Utility Group companies in 2004, including $88 million to CL&P. At December 31, 2004, NU parent had loaned on a temporary basis approximately $110 million to other NU companies, most of which was loaned to the Utility Group companies through the NU money pool. Over the course of 2005, these subsidiaries are expected to repay most of that amount to NU parent, which will use those proceeds and subsidiary dividends to fund NU's common dividend, meet NU parent interest and sinking fund obligations, and infuse additional common equity into the Utility Group companies, particularly CL&P. NU expects to continue to infuse additional equity into the regulated companies for several years beyond 2005. To raise that additional equity, NU expects to sell common shares to the public as early as 2006.

The significant capital requirements of the Utility Group, particularly at CL&P, were one reason that the credit rating outlooks on various NU and subsidiary securities were lowered in 2004. Standard and Poor's (S&P) reduced the outlook on all NU securities it rates to "negative" from "stable." In 2004, S&P lowered its ratings on NGC's debt to BB+, below investment grade, and Moody's Investors Service (Moody's) lowered its ratings on NGC debt to Baa3, its lowest investment grade ratings. Fitch Ratings changed the outlook on NU and CL&P debt to "negative" in January 2005. In February 2005, Moody's reduced by one level the ratings of NU, CL&P, Yankee Gas, and NGC. It lowered by two levels the ratings on WMECO and affirmed with no change the ratings of PSNH. The ratings changes will result in modest increases in future borrowing costs for NU, CL&P and WMECO on their respective revolving credit agreements. The changes are not expected to have a material impact on borrowing costs when the Utility Group seeks long-term financing to support its capital investment plans. NGC did not issue new debt in 2004 and is not expected to issue new debt in the near future. All ratings of NU and subsidiary securities remain investment grade with the exception of Moody's and S&P ratings on NGC's bonds. As a result, those downgrades had no impact on the company's financial results.

On November 8, 2004, NU entered into a 5-year unsecured revolving credit and letter of credit (LOC) facility for $500 million on a short-term basis. This facility is intended to provide liquidity, LOCs and necessary capital for NU Enterprises. At December 31, 2004, there were $100 million of borrowings and $48.9 million of LOCs outstanding under this credit facility. For more information regarding the NU parent revolving credit facility, see Note 2, "Short-Term Debt," to the consolidated financial statements.

Utility Group: On November 8, 2004, the Utility Group entered into a 5-year unsecured revolving credit facility for $400 million. Under this credit facility, CL&P is able to borrow up to $200 million, and PSNH, WMECO, and Yankee Gas will be able to borrow up to $100 million each on a short-term basis. There were $80 million in borrowings outstanding under this credit facility at December 31, 2004. For more information regarding the Utility Group revolving credit facility, see Note 2, "Short-Term Debt" to the consolidated financial statements.

In addition to its revolving credit line, CL&P has an arrangement with a financial institution under which CL&P can sell up to $100 million of accounts receivable and unbilled revenues. At December 31, 2004, CL&P had sold accounts receivable totaling $90 million to that financial institution. For more information regarding the sale of receivables, see Note 10, "Summary of Significant Accounting Policies — Sale of Receivables" to the consolidated financial statements.

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

During 2004, as part of the approved SMD settlement agreement, CL&P paid $83 million to its suppliers, of which $40.5 million was paid to affiliate Select Energy, and refunded $75 million to its customers. Of the combined payment and refund amount totaling $158 million, $124 million was funded from an escrow fund that was established during 2003 and 2004 as these SMD costs were being collected from customers. Additionally, the DPUC ordered a refund of $88.5 million in CTA/System Benefits Charge (SBC) overcollections over a seven-month period beginning with October 2004 consumption. The combination of the SMD and CTA/SBC refunds, when combined with CL&P's proposed capital expenditures, will negatively impact CL&P's liquidity. However, CL&P expects no difficulty in meeting these additional cash requirements.

Under FERC policy, transmission owners may capitalize debt and equity costs during the construction period through an allowance for funds used during construction (AFUDC). Debt costs capitalized offset interest expense with no impact on net income, while equity costs capitalized increase net income. CL&P expects to fund its construction expenditures with approximately 45 percent equity and 55 percent debt.

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

On September 23, 2004, WMECO issued $50 million of 30-year senior unsecured notes at a fixed interest rate of 5.9 percent. Proceeds were used to finance a trust fund that will be used to meet WMECO's prior spent nuclear fuel liability of $49.3 million at December 31, 2004 which is recorded in long-term debt on the consolidated balance sheets. At December 31, 2004, the prior spent nuclear fuel trust totaled $49.3 million.

On January 30, 2004, Yankee Gas issued $75 million of 10-year first mortgage bonds carrying an interest rate of 4.8 percent. Yankee Gas issued an additional $50 million of 15-year first mortgage bonds with an interest rate of 5.26 percent on November 15, 2004. The proceeds from the issuance of these bonds were primarily used to repay short-term debt incurred to redeem long-term debt.

NU Enterprises: During 2004 NGC repaid approximately $32 million of long-term debt and is scheduled to meet $37.5 million of sinking fund maturities in 2005. SESI borrowed a total of $7.8 million during 2004 to finance the implementation of energy saving improvements at customer facilities. In 2004, SESI sold $30 million of receivables related to the energy savings contract projects. The transfer of receivables to the unaffiliated third party qualified as a sale under Statement of Financial Accounting Standards (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities — A Replacement of SFAS No. 125." Accordingly, the $30 million sold at December 31, 2004 is not included as debt in the consolidated financial statements. At December 31, 2004 and 2003, SESI had $93.2 million and $118 million of long-term debt outstanding, respectively. Funds to repay these borrowings are provided by SESI's energy savings contract project revenues. Performance of these energy savings contract projects is guaranteed by NU.

For information regarding SESI's off-balance sheet arrangements, see "Off-Balance Sheet Arrangements," included in this Management's Discussion and Analysis.

Nuclear Decommissioning and Plant Closure Costs

The Connecticut Yankee Atomic Power Company (CYAPC) is currently in litigation with Bechtel Power Corporation (Bechtel) over the termination of its decommissioning contract. On June 13, 2003, CYAPC gave notice of the termination of its contract with Bechtel for the decommissioning of its nuclear power plant. CYAPC terminated the contract due to Bechtel's incomplete and untimely performance and refusal to perform the remaining decommissioning work. Bechtel has departed the site, and the decommissioning responsibility has been transitioned to CYAPC, which has recommenced the decommissioning process.

CYAPC's estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised estimate reflects the increases in the projected costs of spent fuel storage, increased security and liability and property insurance costs, and the fact that CYAPC is now self-performing all work to complete the decommissioning of the plant due to the termination of the decommissioning contract with Bechtel in July 2003. NU's share of CYAPC's increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CYAPC filed with the FERC for recovery of these increased costs. In the filing, CYAPC sought to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection beginning on February 1, 2005 subject to refund, and scheduled hearings for May 2005. In total, NU's estimated remaining decommissioning and plant closure obligation for CYAPC is $308.7 million at December 31, 2004.

On June 10, 2004, the DPUC and Office of Consumer Counsel (OCC) filed a petition seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. On August 30, 2004, the FERC denied this petition. On September 29, 2004, the DPUC and OCC asked the FERC to reconsider the petition. On October 29, 2004, the FERC issued an order granting further consideration regarding the DPUC's and OCC's petition for reconsideration. No hearing date has been established for this reconsideration.

On February 22, 2005, the DPUC filed testimony with the FERC. In its filed testimony, the DPUC argues that approximately $215 million to $225 million of CYAPC's requested increase is due to CYAPC's imprudence in managing the decommissioning project while Bechtel was the contractor. Therefore, the DPUC recommends a total disallowance of between $225 million to $234 million. Hearings are scheduled to begin on June 1, 2005. NU's share of the DPUC's recommended disallowance is between $110 million to $115 million.

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

In the prejudgment remedy proceeding before the Connecticut Supreme Court (the Court), Bechtel sought garnishment of the CYAPC decommissioning trust and related payments. In October 2004, Bechtel and CYAPC entered into an agreement under which Bechtel waived its right to seek garnishment of the decommissioning trust and related payments in return for the potential attachment of CYAPC's real property in Connecticut and the escrowing of $41.7 million the sponsors are scheduled to pay to CYAPC through June 30, 2007 with respect to CYAPC's common equity. This stipulation is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. CYAPC has contested the attachability of such assets. The DPUC is an intervener in this proceeding.

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

The Yankee Companies filed litigation in 1998 charging that the federal government breached contracts it entered into with each company in 1983 under the Nuclear Waste Policy Act of 1982 (the Act). Under the Act, the United States Department of Energy (DOE) was to begin removing spent nuclear fuel from the nuclear plants of Yankee Atomic Electric Company (YAEC), Maine Yankee Atomic Power Company (MYAPC) and CYAPC no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and spent nuclear fuel is stored on the sites of the Yankee Companies' plants. YAEC, MYAPC and CYAPC collected the funds for payments into the nuclear waste fund from wholesale utility customers under FERC-approved contract rates.The wholesale utility customers in turn collect these payments from their retail electric customers. The

Yankee Companies' individual damage claims attributed to the government's breach totaling $548 million are specific to each plant and include incremental storage, security, construction and other costs through 2010, which is the earliest date the DOE projects that it will begin removing nuclear fuel. The YAEC damage claim is $191 million, the MYAPC claim is $160 million and the CYAPC claim is $197 million.

The DOE trial ended on August 31, 2004 and a verdict has not been reached. The current Yankee Companies' rates do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

Business Development and Capital Expenditures

Consolidated: In 2004, NU's capital expenditures totaled $643.8 million, compared with depreciation of $224.9 million. In 2003 and 2002, capital expenditures totaled $563.6 million and $510.5 million, respectively, compared with depreciation of $204.4 million and $205.6 million, respectively. In 2005, capital expenditures are projected to total approximately $740 million, compared with projected depreciation of approximately $240 million. The increasing level of capital expenditures is driven primarily by a need to improve the capacity and reliability of NU's regulated energy delivery system. That increased level of capital expenditures, compared with depreciation levels, also is increasing the amount of plant in service and the regulated companies' earnings base, provided NU's Utility Group companies achieve timely recovery of their investment.

Utility Group:

CL&P: In December 2003, the DPUC approved $900 million of distribution capital expenditures for CL&P from 2004 through 2007. Those expenditures are intended to improve the reliability of the distribution system and to meet growth requirements on the distribution system. In 2004, CL&P's distribution capital expenditures totaled $241.8 million, compared with $258.7 million in 2003 and $219.7 million in 2002. In 2005, CL&P projects distribution capital expenditures of approximately $230 million.

CL&P's transmission capital expenditures totaled $128.1 million in 2004, compared with $63.5 million in 2003 and $39.1 million in 2002. In 2005, CL&P's transmission capital expenditures are projected to total approximately $190 million. The primary reason for the increase projected for 2005 is the expectation that construction will increase in the spring of 2005 on a new 21-mile, 345 kV transmission project between Bethel, Connecticut and Norwalk, Connecticut. The CSC initially approved that project in July 2003.

On August 19, 2004, a Connecticut Superior Court judge dismissed an appeal by the City of Norwalk of the permit granted to CL&P by the CSC to construct a 345 kV transmission project from Bethel, Connecticut to Norwalk, Connecticut. Based upon a recently completed estimate, the project is currently projected to cost between $300 million and $350 million. The project is expected to begin to alleviate identified reliability issues in southwest Connecticut and to help offset rising customer costs for all of Connecticut. Work on the related substations has begun, and work on the transmission lines is expected to start in March 2005 after receiving permits from the towns and the Connecticut Department of Transportation. The major line construction contracts were signed in early March 2005. Management estimates a project completion date of December 2006. At December 31, 2004, CL&P has capitalized $65 million of costs associated with this project.

On October 9, 2003, CL&P and The United Illuminating Company (UI) filed for approval at the CSC for a separate 69-mile 345 kV transmission line from Middletown, Connecticut to Norwalk, Connecticut. Construction is expected to commence after the final route and configuration are determined by CSC. CL&P and UI initially estimated a cost of $620 million for the total project. In June 2004, after the New England Independent System Operator (ISO-NE) raised concerns over the amount of underground line that had been proposed, the CSC requested that a committee comprised of representatives of CL&P, UI and ISO-NE study various alternatives and reach a consensus on the proposed project configuration. The report was filed on December 20, 2004 and recommended a maximum of 24 miles of underground line. On December 28, 2004 CL&P and UI filed updated cost estimates with the CSC which reflect changes needed to address technical issues introduced by the extensive amount of underground transmission being proposed and a two-year delay in the project in-service date from 2007 to 2009. The new estimates place the cost of the project between $840 million and $990 million. The variation in the cost range is due to unknown conditions that may be encountered during construction and a provision for other contingencies. Additional steps being considered by the CSC to lower magnetic fields along the overhead portion of the proposed route would add between $70 million and $80 million to the estimated cost. The CSC completed hearings on the proposal and the alternatives on February 17, 2005, and a ruling on the proposed project is expected by April 7, 2005. At December 31, 2004, CL&P has capitalized $18 million associated with this project.

On October 1, 2004, CL&P and the Long Island Power Authority (LIPA) jointly filed plans with the Connecticut Department of Environmental Protection to replace an undersea 13-mile electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York, consistent with a comprehensive settlement agreement reached on June 24, 2004. This project is estimated to cost in the range of $114 million to $135 million with CL&P and LIPA each owning approximately 50 percent of the line. The cost range reflects that vendor contracts have not yet been signed. The project has received CSC approval, and federal and New York state approvals are expected in 2005. Pending final approval, construction activities are scheduled to begin in the fall of 2006. Management expects the line to be in service by the middle of 2008. At December 31, 2004, CL&P has capitalized $7 million of costs related to this project.

In May 2004, CL&P applied to the CSC to construct two 115 kV 9-mile underground transmission lines between Norwalk, Connecticut and Stamford, Connecticut. The project is expected to cost approximately $120 million and will help meet the growing electric demands in the area. Management expects the lines to be in service by 2008. At December 31, 2004, CL&P has capitalized $3 million of costs related to this project.

During 2004, NU placed in service $123 million of electric transmission projects. These projects included CL&P's $38 million upgrade of a transmission substation in Stamford, Connecticut that will allow additional electricity to be imported into southwest Connecticut.

Yankee Gas: On September 3, 2004, the DPUC approved the application by Yankee Gas to construct a LNG storage facility in Waterbury, Connecticut, at an expected cost of $108 million that is capable of storing the equivalent of 1.2 billion cubic feet of natural gas. On October 15, 2004, Yankee Gas signed a contract for the design and building of the facility, which will be filled through both liquefaction of natural gas on-site and the transportation of LNG from off-site locations. Formal groundbreaking for the project occurred on January 27, 2005, and management expects the facility to become operational in time for the 2007/2008 heating season. At December 31, 2004, Yankee Gas has capitalized $12.9 million of costs related to this project.

On November 1, 2004, Yankee Gas placed in service a new nine-mile gas line to connect its system in southeast Connecticut to the New England Gas Company (NEGASCO) system in Rhode Island. The construction project and a 20-year contract between Yankee Gas and NEGASCO were previously approved by the DPUC and related interstate transportation services by the FERC.

PSNH: In 2004, PSNH's capital expenditures totaled $143.6 million, compared with $105.4 million in 2003 and $107 million in 2002. PSNH's capital expenditures are projected to increase to approximately $150 million in 2005, primarily as a result of the conversion of one of three 50 megawatt units at the coal-fired Schiller Station to burn wood (Northern Wood Power Project). Construction of the $75 million Northern Wood Power Project has begun and is expected to be completed by late 2006. The NHPUC's 2004 approval of the project has been appealed to the New Hampshire Supreme Court brought by some of New Hampshire's existing wood-fired generating plant owners. Management does not believe that the appeal will negatively affect PSNH's ability to complete the Northern Wood Power Project.

In addition to the Northern Wood Power Project, PSNH's capital spending in 2005 will be driven in part by its agreement in its delivery charge 2004 rate case settlement to invest approximately $60 million annually in its distribution capital improvement program.

WMECO: In 2004, WMECO's capital expenditures totaled $38.6 million, compared with $33.3 million in 2003 and $26.5 million in 2002. As part of WMECO's rate settlement approved by the DTE on December 29, 2004, WMECO agreed to invest not less than $24 million in capital expenditures in 2005 and 2006 related to reliability improvements.

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

NU Enterprises: In 2004, capital expenditures totaled $11.8 million at NGC, $1.5 million at HWP, and $4.3 million at other NU Enterprises businesses. Capital expenditures at NGC in 2004 included the final work on a $25 million project to increase the capacity of the Cabot conventional hydroelectric station in Massachusetts by 9 MW to 62 MW. HWP is evaluating spending approximately $14 million in 2005 and 2006 to meet new Massachusetts clean air requirements without which HWP's Mt. Tom coal-fired generating station would be required to cease operation in October 2006. NGC's capital expenditures in 2005 are projected to total approximately $10 million.

Transmission Access and FERC Regulatory Changes

NU companies CL&P, WMECO and PSNH are members of the New England Power Pool (NEPOOL) and, since 1997, have provided regional open access transmission service over their combined transmission system under the NEPOOL Open Access Transmission Tariff, which is administered by ISO-NE and local open access transmission service under the NU Companies Open Access Tariff No. 10, which the NU companies administer.

On October 31, 2003, ISO-NE, along with NU and six other New England transmission owning companies, filed a proposal with the FERC to create a Regional Transmission Organization (RTO) for New England in compliance with a 1999 FERC order calling on all transmission owners to voluntarily join RTOs (Order 2000). The RTO is intended to strengthen the independent and efficient management of the region's power system while ensuring that customers in New England continue to have highly reliable service and realize the benefits of a competitive wholesale energy market.

In a separate filing made on November 4, 2003, the New England transmission owning companies requested, consistent with the FERC's proposed pricing policy for RTOs, that the FERC approve a single ROE for regional and local transmission service rates that would consist of a proposed 12.8 percent base ROE as well as incentive adders of 0.5 percent for joining a RTO and 1.0 percent for constructing new transmission facilities approved by the RTO.

On March 24, 2004, the FERC issued an order conditionally accepting the New England RTO proposal but set for hearing the determination of the appropriate base ROE for transmission rates under the RTO and the clarification as to which facilities the 1.0 percent incentive adder should apply. The 0.5 percent ROE adder was accepted for regional rates.

On November 3, 2004, the FERC issued an order that 1) determined that the New England transmission owners' methodology used to calculate the proposed ROE is appropriate, 2) clarified the application of the 0.5 percent incentive adder for joining a RTO for regional assets and reaffirmed the appropriateness of the 1.0 percent incentive adder for new investments; however, it left still unresolved the type of investments to which the 1.0 percent incentive adder should apply, and 3) approved certain compliance items that were required by the FERC's March 24, 2004 order.

While the order approved the methodology that had been proposed by the transmission owners for calculating the base ROE, it determined that the actual base ROE would be determined following the conclusion of an ordered hearing, which commenced on January 25, 2005. As part of the hearing procedures, the New England transmission owners submitted supplemental testimony supporting their ROE proposal on January 10, 2005 that, among other things, updated the ROE calculations submitted with the November filing. The decision on the ROE incentive adders could result in a different ROE being utilized in the calculation of Regional Network Service (RNS) tariffs than the ROE utilized in the calculation of Local Network Service (LNS) tariffs. An initial administrative law judge decision on these issues is expected in May 2005, and a final ruling regarding these issues is expected by the first quarter of 2006.

In January 2005, the New England transmission owners voted affirmatively to approve activation of the RTO, which occurred on February 1, 2005. As of February 1, 2005, transmission rates were adjusted to reflect the ROEs proposed by the New England transmission owners in the original RTO filing (12.8 percent plus the requested 0.5 percent), subject to refund to reflect the ROE resulting from the ultimate outcome of the hearings. Management cannot at this time predict the ultimate ROE that will be determined following the hearings.

Utility Group Regulatory Issues and Rate Matters

Transmission: Wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU's wholesale transmission revenues are collected through a combination of the RNS tariff and NU's LNS tariff. NU's LNS tariff is reset on June 1st of each year to coincide with the change in RNS rates. Additionally, NU's LNS tariff provides for a true-up to actual costs, which ensures that NU recovers its total transmission revenue requirements, including the allowed ROE. Through December 31, 2004, this true-up has resulted in the recognition of a $4.6 million regulatory liability for refund to electric distribution companies, including CL&P, PSNH and WMECO.

On June 14, 2004, the transmission segment reached a settlement agreement with the parties to its rate case, which allows NU to implement formula-based rates as proposed with an allowed ROE of 11.0 percent. On September 16, 2004, the FERC approved the settlement agreement. The retroactive impact of the change in ROE from 11.75 percent to 11.0 percent reduced earnings by $1 million and $0.1 million, in 2004 and 2003, respectively. Effective February 1, 2005, the 11.0 percent ROE was increased to the aforementioned 12.8 percent ROE.

On February 1, 2005, consistent with its tariff, NU's transmission segment implemented an increase to its transmission tariff that is expected to increase 2005 revenues by approximately $8 million over 2004 transmission revenues.

A significant portion of NU's transmission businesses' revenue is from charges to NU's electric distribution companies CL&P, PSNH and WMECO. These companies recover transmission charges through rates charged to their retail customers. WMECO has a rate tracking mechanism to track transmission costs charged in distribution rates to the actual amount of transmission charges incurred. The 2004 rates set in the CL&P distribution rate case contained a level of transmission revenue sufficient to recover CL&P's 2004 transmission costs. On February 1, 2005, CL&P filed an application with the DPUC to obtain approval to defer for future recovery in its retail transmission rate the increased transmission costs that CL&P is incurring as of February 1, 2005. The June 1, 2005 PSNH retail rate increase includes revenues to recover expected transmission costs. Neither CL&P nor PSNH currently have transmission rate tracking mechanisms that track transmission costs.

LICAP: In March 2004, ISO-NE filed a proposal at the FERC to implement locational installed capacity (LICAP) requirements. LICAP is an administratively determined electric generation asset capacity pricing mechanism intended to provide a revenue stream sufficient to maintain existing generation assets and encourage the construction of new generation assets at levels sufficient to serve peak load, plus a reserve margin and a cushion. In June 2004, the FERC ordered the creation of five LICAP zones and accepted ISO-NE's demand curve methodology. The FERC ordered LICAP to be implemented by January 1, 2006, and set certain issues pertaining to the demand curve for hearings. Hearings began at the end of February 2005. A FERC decision is anticipated in the fall of 2005. Management cannot at this time predict the outcome of this FERC proceeding.

CL&P, PSNH and WMECO will incur LICAP charges. Because southwest Connecticut is a constrained area with insufficient generation assets, CL&P could incur LICAP costs totaling several hundred million dollars. These costs would be recovered from CL&P's customers through the FMCC mechanism. PSNH and WMECO will also recover these costs from customers.

Connecticut — CL&P:

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

CL&P filed a petition for reconsideration of certain items in the final decision on December 31, 2003. The DPUC issued a final decision on the petition on August 4, 2004. The final decision authorized CL&P to use existing CTA overrecoveries in lieu of an increase in rates to recover approximately $24 million, which is the net present value of the $32 million sought in the reconsideration. The final decision had a 2004 positive pre-tax impact of $11.5 million ($6.9 million after-tax) on CL&P. The remaining amount of $12.5 million is being amortized over four years beginning August 1, 2004 as an increase to revenues as the related costs to be recovered are incurred.

Under the Act, CL&P is allowed to collect a fixed procurement fee of 0.50 mills per kWh from customers who purchase TSO. One mill is equal to one-tenth of a cent. That fee can increase to 0.75 mills if CL&P outperforms certain regional benchmarks. The fixed portion of the procurement fee amounted to approximately $12 million (approximately $7 million after-tax) for 2004. On September 15, 2004, CL&P submitted to the DPUC its proposed methodology to calculate the variable portion (incentive portion) of the procurement fee. On November 18, 2004 the DPUC suspended this proceeding and has not indicated when the schedule will be resumed. The variable portion of the procurement fee has not yet been reflected in earnings.

Retail Transmission Rate Filing: On February 1, 2005, CL&P filed an application with the DPUC to obtain approval to defer for future recovery in its retail transmission rate the increased transmission costs that CL&P is incurring as of February 1, 2005. If the DPUC does not approve this deferral, CL&P's application provides for an alternate proposal to increase its retail transmission rate to recover an additional $7.6 million on an annual basis, effective February 1, 2005. Under this proposal the increase would equal $0.00031 per kWh, and would represent approximately a 0.2 percent increase in overall rates as of February 1, 2005. Hearings in this docket have not been scheduled.

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

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

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany tax liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P's request, and on October 24, 2003, CL&P appealed the DPUC's final decision to the Connecticut Superior Court. The appeal has been fully briefed and argued. A decision from the court is not expected to be issued until the second quarter of 2005. If CL&P's request is granted through these court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany tax liability in CTA revenue requirements has been a reduction in revenue of approximately $19 million.

Application for Issuance of Long-Term Debt: On September 9, 2004, CL&P filed an application with the DPUC requesting approval to issue long-term debt in the amount of $600 million during the period February 1, 2005 to December 31, 2007. Additionally, CL&P requested approval to enter into hedging transactions from time to time through December 31, 2007 in connection with any prospective or outstanding long-term debt in order to reduce the interest rate risk associated with the debt or debt issuances. A final decision from the DPUC was issued on January 26, 2005. The final decision approved CL&P's request to issue $600 million in long-term debt through December 31, 2007. Additionally, the final decision approved CL&P's request to enter into hedging transactions in connection with any prospective or outstanding long-term debt in order to reduce the interest rate risk associated with the debt or debt issuances. CL&P plans to issue up to $200 million in long-term debt by the middle of 2005.

CL&P TSO Rates: The vast majority of CL&P's customers buy their energy through CL&P's TSO, rather than buying energy directly from competitive suppliers. On August 1, 2003, CL&P filed with the DPUC to establish TSO rates equal to December 31, 1996 total rate levels. In October 2003, CL&P requested bids from wholesale energy marketers to supply its TSO requirements from 2004 through 2006. Five wholesale marketers supplied CL&P's TSO requirements in 2004, including Select Energy. On December 19, 2003, the DPUC issued a final decision setting the average TSO rate of $0.1076 per kWh effective January 1, 2004. In November 2004, CL&P requested bids from wholesale marketers to supply the TSO requirements in 2005 and 2006 that were not filled in the 2003 solicitation. Due to higher energy prices, the bids received and accepted by CL&P were significantly higher than those accepted in 2003. As a result of the higher supply costs, higher FMCC and a $25.1 million distribution rate increase approved by the DPUC in CL&P's rate case, on November 24, 2004, CL&P requested the DPUC to increase its TSO rate by 16.7 percent in 2005. On December 22, 2004, the DPUC approved the increase of 16.2 percent effective January 1, 2005, although the impact was partially offset by a continuation of the CTA refund. The DPUC also ordered that projected 2004 and 2005 CTA overrecoveries and half of projected 2004 distribution overrecoveries be used to moderate increases for customers that otherwise would occur when the current CTA refund expires on May 1, 2005. Overall, the final decision approved an increase to the January 2004 TSO rates of approximately 10.4 percent, including the effects of existing and new refunds and overrecoveries. The DPUC denied requests by the Connecticut Attorney General and OCC to defer the recovery of higher supplier costs into future years. On February 3, 2005, the OCC filed an appeal with the Connecticut Superior Court challenging this decision. This appeal is identical to the appeal filed with the same court in February 2004 challenging the DPUC's December 2003 decision. Management believes that this appeal will not impact the DPUC's December 22, 2004 order.

Also, pursuant to state law, on December 19, 2003, the DPUC set CL&P's TSO rates for January 1, 2004 through December 31, 2004 and confirmed that state law exempted FMCC, Energy Adjustment Clause (EAC) charges and certain other charges from the statutorily imposed rate cap. The OCC filed appeals of this decision with the Connecticut Superior Court. The OCC claims that the decision improperly implements an EAC charge under Connecticut law, fails to properly define and identify the fees that CL&P will be allowed to collect from customers and improperly calculates base rates for purposes of determining the rate cap. Management believes that these appeals will not impact the TSO rates approved by the DPUC.

On February 1, 2005, CL&P filed for a 1.6 percent increase to rates ($29.2 million) to collect additional FMCC from customers effective May 1, 2005. The increase is necessary to collect costs related to an additional RMR contract related to two generating plants located in southwest Connecticut. The RMR contract has preliminary approval for billing from the FERC and is subject to a future review by the FERC prior to final approval.

Connecticut — Yankee Gas:

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

On October 14, 2004, Yankee Gas filed a settlement agreement with the DPUC. Parties to the settlement agreement included the OCC and the Prosecutorial Division of the DPUC. The settlement agreement increases customer rates by $14 million annually, allows a ROE of 9.9 percent and reduces Yankee Gas' annual expense for plant taken out of service by $5.7 million. As part of the settlement agreement, Yankee Gas agreed not to file a new rate increase application to be effective prior to the earlier of the in-service date of its new LNG facility or July 1, 2007. On December 8, 2004, the DPUC issued a final decision approving the settlement agreement as filed. The rate increase took effect on January 1, 2005.

New Hampshire:

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

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

Transition Energy Service and Default Energy Service: In accordance with the Restructuring Settlement and state law, PSNH files for updated TS/DS rates periodically to ensure timely recovery of its costs. The TS/DS rate recovers PSNH's generation and purchased power costs, including a return on PSNH's generation investment. PSNH defers for future recovery or refund any difference between its TS/DS revenues and the actual costs incurred.

On September 24, 2004, PSNH filed a petition with the NHPUC requesting a change in the TS/DS rate for the period February 1, 2005 through January 31, 2006. In December 2004, PSNH petitioned for a TS/DS rate of $0.0649 per kWh based on updated market information. The NHPUC issued its order approving a TS/DS rate of $0.0649 per kWh on January 28, 2005. This TS/DS rate includes an 11 percent ROE on PSNH's generation assets, which is subject to further review by the NHPUC.

SCRC Reconciliation Filings: The Stranded Cost Recovery Charge (SCRC) allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the NHPUC a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and TS/DS revenues billed with TS/DS costs. The NHPUC reviews the filing, including a prudence review of PSNH's generation operations. The cumulative deferral of SCRC revenues in excess of costs was $208.6 million at December 31, 2004. This cumulative deferral will decrease the amount of non-securitized stranded costs that will have to be recovered from PSNH's customers in the future from $411.3 million to $202.7 million.

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

The 2004 SCRC reconciliation filing is expected to be filed with the NHPUC by May 2, 2005. Management does not expect the NHPUC's review of the 2004 SCRC filing to have a material impact on PSNH's net income or financial position.

The SCRC and TS/DS rate mechanisms currently reconcile accrued expenses with billed revenues on a monthly basis. On May 2, 2005, PSNH expects to file its annual 2004 SCRC and TS/DS reconciliation that will include a request to include unbilled revenues as part of the reconciliation process. This request will allow for the reconciliation of revenues on an accrual basis with the current accrued expenses recovered through the SCRC and TS/DS rate mechanisms, consistent with accrual accounting. At December 31, 2004, the PSNH unbilled revenue balance related to SCRC and TS/DS was $11.7 million and $16.7 million, respectively. If approved, this change will allow for the inclusion of accrued unbilled revenue balances in the recovery of SCRC and TS/DS costs. Management believes that the unbilled revenue balance related to SCRC and TS/DS is probable of being recovered from PSNH's customers.

Wholesale Distribution Rate Case: PSNH is planning to file a wholesale distribution rate case with the FERC in late March 2005. This FERC filing is necessary due to the reclassification of certain assets from PSNH's transmission business to distribution business. PSNH plans to file a revenue requirements analysis in order to recover certain delivery costs arising from the provision of wholesale delivery service to another New Hampshire utility.

Massachusetts:

Transition Cost Reconciliation: On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the DTE. This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The DTE has not initiated its investigation into this filing. WMECO expects to file its 2004 transition cost reconciliation with the DTE on March 31, 2005. The DTE combined the 2003 transition cost reconciliation filing and the 2004 transition cost reconciliation filing into a single proceeding. The timing of this decision in the combined proceeding is uncertain, but management does not expect the outcome to have a material adverse impact on WMECO's net income or financial position.

Distribution Rate Case Settlement Agreement: On December 29, 2004, the DTE approved a rate case settlement agreement submitted by WMECO, the Massachusetts Attorney General's Office, the Associated Industries of Massachusetts, and the Low-Income Energy Affordability Network. The settlement agreement provides for a $6 million increase in WMECO's distribution rate effective January 1, 2005 and an additional $3 million increase in WMECO's distribution rate effective January 1, 2006 and for a decrease in WMECO's transition charge by approximately $13 million annually. The lower transition charge will delay recovery of transition costs and will reduce WMECO's cash flow but not its earnings as part of the rate case settlement. WMECO agreed not to file a full rate case with rates effective prior to January 1, 2007.

NU Enterprises

Business Segments: NU Enterprises aligns its businesses into two business segments: the merchant energy business segment and the energy services and other business segment. The merchant energy business segment includes Select Energy's wholesale and retail marketing businesses. Also currently included in the merchant energy segment are 1,443 MW of generation assets, including 1,296 MW of pumped storage and hydroelectric generation assets at NGC and 147 MW of coal-fired generation assets at HWP. The wholesale business primarily serves full requirements sales to LDCs and bilateral sales to other load serving counterparties. To serve these customers, Select Energy relies on its own generation and an inventory of energy contracts.

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

Results: NU Enterprises lost $15.1 million in 2004. This loss includes a $48.3 million mark-to-market loss associated with certain wholesale natural gas positions. In 2003, NU Enterprises lost $3.4 million. This loss includes a $35.6 million charge associated with SMD. NU Enterprises' merchant energy retail marketing business earnings improved to net income of $4.9 million in 2004, compared with a loss of $1.8 million in 2003.

NU Enterprises' energy services business segment lost $2.3 million in 2004 compared with earnings of approximately $2.6 million in 2003. The 2004 earnings decrease is the result of losses recorded on a major construction contract.

Outlook: On March 9, 2005, NU completed its previously announced comprehensive review of its competitive energy businesses and decided that NU Enterprises will exit the wholesale marketing business. NU also concluded that NU Enterprises' energy services businesses are not central to NU's long-term strategy and do not meet the company's expectations of profitability. As a result, the company will explore ways to divest those businesses in a manner that maximizes their value. NU will retain its competitive generation and retail energy marketing businesses because it believes that the generation assets and retail business are competitively positioned to create significant opportunities for those businesses over the next several years.

NU Enterprises' 2005 earnings will be impacted by many factors, including the amount of asset impairments or losses on disposals that could result from the decision to explore divesting the services segment, the mark-to-market loss that may result from the application of mark-to-market accounting to certain wholesale marketing contracts until those contracts are sold or until the commodities are delivered, and other closure costs.

Intercompany Transactions: CL&P's standard offer purchases from Select Energy represented $502 million for the year ended December 31, 2004, compared with $558 million during the same period in 2003. Other energy purchases between CL&P and Select Energy totaled $109.3 million for the year ended December 31, 2004 and $130 million during the same period in 2003. Additionally, WMECO's purchases from Select Energy represented $108.5 million for the year ended December 31, 2004, compared with $143 million during the same period in 2003. These amounts are eliminated in consolidation.

NU Enterprises' Market and Other Risks

Overview: The decision to exit the wholesale marketing business will change the risk profile of NU Enterprises in 2005. Subsequent to the sale of the wholesale marketing business, NU Enterprises will continue to be exposed to certain market risks; however, management believes that those risks will be reduced. The merchant energy business segment will be comprised of generation assets and the retail marketing segment, which will enter into contracts of varying lengths of time to buy and sell energy commodities, including electricity, natural gas, and oil to retail customers. Market risk represents the loss that may affect the merchant energy business segment's financial results, primarily Select Energy, due to adverse changes in commodity market prices.

Risk management within Select Energy has been organized to address the market, credit and operational exposures arising from the merchant energy business segment. The framework for managing these risks is set forth in NU's risk management policies and procedures, which are reviewed by the NU Board of Trustees on an as needed basis.

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

The pricing terms of full requirement contracts and of supply contracts can affect the timing of Select Energy's margins. Many full requirements contracts have higher prices in certain months, while many supply contracts have one price for the entire contract term. Accordingly, Select Energy's margins will tend to be higher in the months when the full requirements contract price is higher and lower or could be negative when the full requirements contract price is lower.

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

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

The electricity contracts were accounted for on the accrual basis through 2004, which would have resulted in earnings recognition when the electricity would have been delivered to customers in 2005 and 2006. These electricity purchase contracts were to be used to meet electricity sales contract requirements, which was a key component of the merchant energy wholesale business. Until the decision to cease wholesale marketing activities was made, management believed that this electricity would be delivered to its customers. The decision on March 9, 2005 to exit the wholesale marketing business changed management's conclusion regarding the likelihood that many wholesale marketing contracts would result in delivery to customers. This in turn resulted in a change in March 2005 from accrual accounting to fair value accounting for the wholesale marketing contracts that will be sold. Under fair value accounting, changes in the fair value of these contracts will impact 2005 earnings until the contracts are completed or sold.

The natural gas contracts are recorded at current fair value with changes in fair value impacting earnings. At December 31, 2004 the fair value of the natural gas contracts was a negative $77.7 million. The changes in fair values totaling a negative $77.7 million increased fuel, purchased and net interchange power in 2004. Of the total fair value of negative $77.7 million, approximately negative $68 million relates to 2005 with approximately negative $10 million related to 2006.

The use of fair value accounting for the aforementioned natural gas and electricity contracts has exposed and will continue to expose Select Energy's and NU's earnings to future changes in natural gas and electricity prices, which could be significant. This has and can reasonably be expected to create uncertainty in 2005 regarding Select Energy's and NU's earnings and earnings trends.

The natural gas contracts are included in non-trading derivative assets and liabilities in the table in Note 3, "Derivative Instruments," to the consolidated financial statements.

Retail Marketing Activities: Select Energy manages its portfolio of retail marketing contracts to maximize value while operating within NU's corporate risk tolerance. Select Energy generally acquires retail customers in small increments, which while requiring careful sourcing allows energy purchases to be acquired in small increments with low risk. However, fluctuations in prices, fuel costs, competitive conditions, regulations, weather, transmission costs, lack of market liquidity, plant outages and other factors can all impact the retail business adversely from time to time.

Generation Activities: The generation assets, either owned by NU Enterprises or contracted with third parties, are subject to certain operational risks, including but not limited to the length of scheduled and non-scheduled outages, bidding and scheduling with various ISOs, environmental issues and fuel costs. Generation is also subject to various federal, state and local regulations. These risks may result in changes in the anticipated gross margins which Select Energy realizes from its generation portfolio/activities.

Hedging and Other Non-Trading: For information on derivatives used for hedging purposes and non-trading derivatives, see Note 3, "Derivative Instruments," to the consolidated financial statements.

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

At December 31, 2004, Select Energy had trading derivative assets and trading derivative liabilities as follows:

(Millions of Dollars)	2004
Current trading derivative assets	$49.6
Long-term trading derivative assets	31.7
Current trading derivative liabilities	(46.2)
Long-term trading derivative liabilities	(5.5)
Portfolio position	$29.6

There can be no assurances that Select Energy will realize cash corresponding to the present positive net fair value of its trading positions. Numerous factors could either positively or negatively affect the realization of the net fair value amount in cash. These include the sales price to be received on the sale of these contracts, the volatility of commodity prices until the contracts are sold, the outcome of future transactions, the performance of counterparties, and other factors.

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

The methods used to determine the fair value of energy trading contracts are identified and segregated in the table of fair value of contracts at December 31, 2004. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange futures and options that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity or natural gas, and are marked to the mid-point of bid and ask market prices. Currently, Select Energy has one contract for which a portion of the contract's fair value is determined based on a model or other valuation method. The model utilizes natural gas prices and a conversion factor to electricity. Management recorded a modeling reserve to reduce the value of the

contract for those years that do not have liquid prices to zero. Broker quotes for electricity at locations that Select Energy has entered into deals are available through the year 2007. For all natural gas positions, broker quotes extend through 2013.

Generally, valuations of short-term contracts derived from quotes or other external sources are more reliable should there be a need to liquidate the contracts, while valuations for longer-term contracts are less certain. Accordingly, there is a risk that contracts will not be realized at the amounts recorded. However, Select Energy has obtained corresponding purchase or sale contracts for a large portion of the trading contracts that have maturities in excess of one year.

Because these trading contracts are sourced, changes in the value of these contracts due to fluctuations in commodity prices are not expected to significantly affect Select Energy's earnings.

As of and for the years ended December 31, 2004 and 2003, the sources of the fair value of trading contracts and the changes in fair value of these trading contracts are included in the following tables. Intercompany transactions are eliminated and not reflected in the amounts below.

(Millions of Dollars)	Fair Value of Trading Contracts at December 31, 2004			
Sources of Fair Value	Maturity Less Than One Year	Maturity Of One to Four Years	Maturity In Excess of Four Years	Total Fair Value
Prices actively quoted	**$0.7**	**$ —**	**$ —**	**$ 0.7**
Prices provided by external sources	**2.8**	**13.6**	**12.5**	**28.9**
Totals	**$3.5**	**$13.6**	**$12.5**	**$29.6**

(Millions of Dollars)	Fair Value of Trading Contracts at December 31, 2003			
Sources of Fair Value	Maturity Less Than One Year	Maturity Of One to Four Years	Maturity In Excess of Four Years	Total Fair Value
Prices actively quoted	$0.2	$0.1	$ —	$ 0.3
Prices provided by external sources	6.9	9.6	15.7	32.2
Totals	$7.1	$9.7	$15.7	$32.5

The fair value of energy trading contracts decreased to $29.6 million at December 31, 2004 from $32.5 million at December 31, 2003. The change in the fair value of the trading portfolio is primarily attributable to contracts being settled in 2004, offset by changes in the fair value of contracts. The change in fair value attributable to changes in valuation techniques and assumptions of $2.3 million in 2003 resulted from a change in the discount rate management uses to determine the fair value of trading contracts. In the second quarter of 2003, the rate was changed from a fixed rate of 5 percent to a market-based LIBOR discount rate to better reflect current market conditions.

	Years Ended December 31, **2004**	2003
(Millions of Dollars)	Total Portfolio Fair Value	
Fair value of trading contracts outstanding at the beginning of the year	**$32.5**	$41.0
Contracts realized or otherwise settled during the period	**(10.5)**	(10.7)
Changes in fair values attributable to changes in valuation techniques and assumptions	**—**	2.3
Changes in fair value of contracts	**7.6**	(0.1)
Fair value of trading contracts outstanding at the end of the year	**$29.6**	$32.5

For further information regarding Select Energy's derivative contracts, see Note 3, "Derivative Instruments," and Note 12, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

Changing Market: In general, the market for energy products has become shorter term in nature with less liquidity, market pricing information is less readily available and participants are sometimes unable to meet Select Energy's credit standards without providing cash or LOC support. Select Energy is being adversely affected by these factors, and there could be a continuing adverse impact on Select Energy's business.

In addition, NU Enterprises has concluded that competition has increased significantly in the wholesale power market in New England over the last six months of 2004. This increase in competition may affect Select Energy's profitability by reducing the number of bids won and by reducing the margins on those bids which are won.

Changes are occurring in the administration of transmission systems in territories in which Select Energy does business. As the market continues to evolve, there could be additional challenges or opportunities that management cannot determine at this time.

In March 2004, ISO-NE filed a proposal at the FERC to implement LICAP requirements. LICAP is an administratively determined electric generation asset capacity pricing mechanism intended to provide a revenue stream sufficient to maintain existing generation assets and encourage the construction of new generation assets at levels sufficient to serve peak load, plus a reserve margin and a cushion. In June 2004, the FERC ordered the creation of five LICAP zones and accepted ISO-NE's demand curve methodology. The FERC ordered LICAP to be implemented by January 1, 2006, and set certain issues pertaining to the demand curve for hearings. Hearings began at the end of February 2005. A FERC decision is anticipated in the fall of 2005. Management cannot at this time predict the outcome of this FERC proceeding.

Depending on the pricing curves that are ultimately implemented LICAP could produce significant benefits for generation assets either owned or leased by NU Enterprises. NU Enterprises owned or leased approximately 300 MW of generation assets in Connecticut and approximately 1,300 MW of generation assets in western Massachusetts.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established written credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in establishing credit limits prior to Select Energy's entering into contracts. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions. At December 31, 2004, approximately 77 percent of Select Energy's counterparty credit exposure to wholesale and trading counterparties was collateralized or rated BBB- or better. Select Energy was provided $57.7 million and $46.5 million of counterparty deposits at December 31, 2004 and December 31, 2003, respectively. For further information, see Note 1Y, "Summary of Significant Accounting Policies — Counterparty Deposits," to the consolidated financial statements.

Select Energy's Credit: A number of Select Energy's contracts require the posting of additional collateral in the form of cash or LOCs in the event NU's ratings were to decline and in increasing amounts dependent upon the severity of the decline. At NU's present investment grade ratings, Select Energy has not had to post any collateral based on credit downgrades. Were NU's unsecured ratings to decline two levels to sub-investment grade, Select Energy could, under its present contracts, be asked to provide at December 31, 2004 approximately $361 million of collateral or LOCs to various unaffiliated counterparties and approximately $140 million to several independent system operators and unaffiliated LDCs, which management believes NU would currently be able to provide, subject to the Securities and Exchange Commission (SEC) limits. NU's credit ratings outlooks are currently stable or negative, but management does not believe that at this time there is a significant risk of a ratings downgrade to sub-investment grade levels.

Consolidated Edison, Inc. Merger Litigation

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

On May 11, 2001, Con Edison filed an amended complaint seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation in an unspecified amount, but which Con Edison's Chief Financial Officer has testified is at least $314 million. NU disputes both Con Edison's entitlement to any damages as well as its method of computing its alleged damages.

The companies completed discovery in the litigation and submitted cross motions for summary judgment. The court denied Con Edison's motion in its entirety, leaving intact NU's claim for breach of the Merger Agreement, and partially granted NU's motion for summary judgment by eliminating Con Edison's claims against NU for fraud and negligent misrepresentation.

An intervener in this litigation has made the claim that NU shareholders at March 5, 2001 are entitled to damages from Con Edison, if any, and not current NU shareholders.

Appeals on this and other issues are now pending and no trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU.

Off-Balance Sheet Arrangements

Utility Group: The CL&P Receivables Corporation (CRC) was incorporated on September 5, 1997, and is a wholly owned subsidiary of CL&P. CRC has an agreement with CL&P to purchase and has an arrangement with a highly-rated financial institution under which CRC can sell up to $100 million of an undivided interest in accounts receivable and unbilled revenues. At December 31, 2004 and 2003, CRC had sold an undivided interest in its accounts receivable and unbilled revenues of $90 million and $80 million, respectively, to that financial institution with limited recourse.

CRC was established for the sole purpose of selling CL&P's accounts receivable and unbilled revenues and is included in the consolidated NU financial statements. On July 7, 2004, CRC renewed its Receivables Purchase and Sale Agreement with CL&P and the financial institution through July 6, 2005, and the termination date of the facility was extended to July 3, 2007. Management plans to renew this agreement prior to its expiration. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140. Accordingly, the $90 million and $80 million outstanding under this facility are not reflected as debt or included in the consolidated financial statements at December 31, 2004 and 2003, respectively.

This off-balance sheet arrangement is not significant to NU's liquidity or other benefits. There are no known events, demands, commitments, trends, or uncertainties that will, or are reasonably likely to, result in the termination, or material reduction in the amount available to the company under this off-balance sheet arrangement.

NU Enterprises: During 2001, SESI created HEC/CJTS Energy Center, LLC (HEC/CJTS) which is a special purpose entity (SPE). SESI created HEC/CJTS for the sole purpose of providing a bankruptcy remote entity for the financing of a construction project. The construction project was the construction of an energy center to serve the Connecticut Juvenile Training School (CJTS). The owner of CJTS, the State of Connecticut, entered into a 30-year lease with HEC/CJTS for the energy center. Simultaneously, HEC/CJTS transferred its interest in the lease with the State of Connecticut to investors who are unaffiliated with NU

in exchange for the issuance of $19.2 million of Certificates of Participation. The transfer of HEC/CJTS's interest in the lease was accounted for as a sale under SFAS No. 140. The debt of $19.2 million created in relation to the transfer of interest and issuance of the Certificates of Participation was derecognized and is not reflected as debt or included in the consolidated financial statements. No gain or loss was recorded. HEC/CJTS does not provide any guarantees or on-going services, and there are no contingencies related to this arrangement.

SESI has a separate contract with the State of Connecticut to operate and maintain the energy center. The transaction was structured in this manner to obtain tax-exempt rate financing and therefore to reduce the State of Connecticut's lease payments.

This off-balance sheet arrangement is not significant to NU's liquidity, capital resources or other benefits. There are no known events, demands, commitments, trends, or uncertainties that will, or are reasonably likely to, result in the termination of this off-balance sheet arrangement.

SESI entered into a master purchase agreement with an unaffiliated third party on April 30, 2002 under which SESI may sell certain receivables that are due or become due under delivery orders issued pursuant to federal energy savings performance contracts. At December 31, 2004, SESI had sold $30 million of receivables related to the installation of the energy efficiency projects under this arrangement. The transfer of receivables to the unaffiliated third party under this arrangement qualified as a sale under SFAS No. 140. Accordingly, the $30 million sold at December 31, 2004 is not included as debt in the consolidated financial statements. Under the delivery order with the United States government, SESI is responsible for on-going maintenance and other services related to the energy efficiency project installation. SESI receives payment for those services in addition to the amounts sold under the master purchase agreement.

SESI has entered into assignment agreements to sell an additional $26.5 million of receivables. This sale will be complete upon customer acceptance of the project installation. Until construction is completed, the advances under the purchase agreement are included in long-term debt in the consolidated financial statements.

This off-balance sheet arrangement is not significant to NU's liquidity or other benefits. There are no known events, demands, commitments, trends, or uncertainties that will, or are reasonably likely to, result in the termination, or material reduction in the amount sold under this off-balance sheet arrangement.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally acceptec in the United States of America requires management to make estimates, assumptions and at times difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact the financial statements of NU. Management communicates to and discusses with NU's Audit Committee of the Board of Trustees all critical accounting policies and estimates. The following are the accounting policies and estimates that management believes are the most critical in nature.

Presentation: In accordance with current accounting pronouncements, NU's consolidated financial statements include all subsidiaries upon which control is maintained and all variable interest entities (VIE) for which NU is the primary beneficiary, as defined. Determining whether the company is the primary beneficiary of a VIE is subjective and requires management's judgment. There are certain variables taken into consideration to determine whether the company is considered the primary beneficiary to the VIE. A change in any one of these variables could require the company to reconsider whether or not it is the primary beneficiary of the VIE. All intercompany transactions between these subsidiaries are eliminated as part of the consolidation process.

NU has less than 50 percent ownership interests in CYAPC, YAEC, MYAPC, and two companies that transmit electricity imported from the Hydro-Quebec system. NU does not control these companies and does not consolidate them in its financial statements. NU accounts for the investments in these companies using the equity method. Under the equity method, NU records its ownership share of the earnings or losses at these companies. Determining whether or not NU should apply the equity method of accounting for an investment requires management judgment.

NU had a preferred stock investment in R. M. Services, Inc. (RMS). Upon adoption of FIN 46, management determined that NU was the primary beneficiary of RMS and subsequently consolidated RMS into its financial statements. The consolidation of RMS resulted in a negative $4.7 million after-tax cumulative effect of an accounting change in the third quarter of 2003. On June 30, 2004, the assets and liabilities of RMS were sold. For more information on RMS, see Note 11, "Summary of Significant Accounting Policies — Accounting for R.M. Services, Inc." to the consolidated financial statements.

In December 2003, the FASB issued a revised version of FIN 46 (FIN 46R). FIN 46R has resulted in fewer NU investments meeting the definition of a VIE. FIN 46R was effective for NU for the first quarter of 2004 and did not have an impact on NU's consolidated financial statements.

Revenue Recognition: Utility Group retail revenues are based on rates approved by the state regulatory commissions. These regulated rates are applied to customers' use of energy to calculate a bill. In general, rates can only be changed through formal proceedings with the state regulatory commissions.

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

Certain Utility Group companies utilize regulatory commission-approved tracking mechanisms to track the recovery of certain incurred costs. The tracking mechanisms allow for rates to be changed periodically, with overcollections refunded to customers or underrecollections collected from customers in future periods.

Wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU's wholesale transmission revenues are collected through a combination of the RNS tariff and NU's LNS tariff. The RNS tariff, which is administered by ISO-NE,

recovers the revenue requirements associated with transmission facilities that are deemed by the FERC to be Pool Transmission Facilities. The LNS tariff, which was accepted by the FERC on October 22, 2003, provides for the recovery of NU's total transmission revenue requirements, net of revenue credits received from various rate components, including revenues received under the RNS rates.

NU Enterprises recognizes revenues at different times for its different business lines. Wholesale and retail marketing revenues are recognized when energy is delivered to customers. Trading revenues are typically recognized as the fair value of trading contracts changes. Service revenues are recognized as services are provided, often on a percentage of completion basis.

Revenues and expenses for derivative contracts that are entered into for trading purposes are recorded on a net basis in revenues when these transactions settle. The settlement of wholesale non-trading derivative contracts for the sale of energy or gas by both the Utility Group and NU Enterprises that are related to customers' needs are recorded in operating expenses. Derivative contracts that hedge an underlying transaction and that qualify for hedge accounting affect earnings when the forecasted transaction being hedged occurs, when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is no longer probable of occurring, or when there is an accumulated other comprehensive loss and when the hedge and the forecasted transaction being hedged are in a loss position on a combined basis. The settlement of hedge derivative contracts is recorded in the same revenue or expense line as the transaction being hedged. For further information regarding the accounting for these contracts, see Note 1F, "Summary of Significant Accounting Policies — Derivative Accounting," to the consolidated financial statements.

Utility Group Unbilled Revenues: Unbilled revenues represent an estimate of electricity or gas delivered to customers that has not been billed. Unbilled revenues represent assets on the balance sheet that become accounts receivable in the following month as customers are billed.

The estimate of unbilled revenues is sensitive to numerous factors that can significantly impact the amount of revenues recorded. Estimating the impact of these factors is complex and requires management's judgment. The estimate of unbilled revenues is important to NU's consolidated financial statements as adjustments to that estimate could significantly impact operating revenues and earnings.

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

During 2004 the unbilled sales estimates for all Utility Group companies were tested using the cycle method. The cycle method uses the billed sales from each meter reading cycle and an estimate of unbilled days in each month based on the meter reading schedule. The cycle method is historically more accurate than the requirements method when used in a mostly weather-neutral month. The cycle method testing was performed in the second and fourth quarters of 2004 but did not have a material impact on earnings.

During 2003 the cycle method resulted in adjustments to the estimate of unbilled revenues that had a net positive after-tax earnings impact of approximately $4.6 million. The 2003 positive after-tax impacts on CL&P, PSNH, and WMECO were $7.2 million, $3.3 million, and $0.3 million, respectively. There was a negative after-tax impact on Yankee Gas of $6.2 million, including certain gas cost adjustments.

Derivative Accounting: Effective January 1, 2001, NU adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Most of the contracts comprising Select Energy's wholesale and retail marketing activities are derivatives, and many Utility Group contracts for the purchase or sale of energy or energy-related products are derivatives. The application of derivative accounting under SFAS No. 133, as amended, is complex and requires management judgment in the following respects: election and designation of the normal purchases and sales exception, identification of derivatives and embedded derivatives, identifying hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on NU's consolidated net income.

The judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusions that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting would be terminated and fair value accounting would be applied. Cash flow hedge contracts that are designated as hedges for contracts for which the company has elected the normal purchases and sales exception can continue to be accounted for as cash flow hedges only if the normal exception for the hedged contract continues to be appropriate. If the normal exception is terminated, then the hedge designation would be terminated at the same time.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which amended existing derivative accounting guidance. This new statement incorporates interpretations that were included in previous Derivative Implementation Group (DIG) guidance, clarifies certain conditions, and amends other existing pronouncements. It was effective for contracts entered into or modified after June 30, 2003. Management has determined that the adoption of SFAS No. 149 did not change NU's accounting for wholesale and retail marketing contracts or the ability of NU Enterprises to elect the normal purchases and sales exception. The adoption of SFAS No. 149 resulted in fair value accounting for certain Utility Group contracts that are subject to unplanned netting and do not meet the definition of capacity contracts. These non-trading derivative contracts are recorded at fair value at December 31, 2004 and 2003 as derivative assets and liabilities with offsetting amounts recorded as regulatory liabilities and assets because the contracts are part of providing regulated electric or gas service.

Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and 'Not Held for Trading Purposes' as Defined in EITF Issue No. 02-3," was derived from EITF Issue No. 02-3, which requires net reporting in the income statement of energy trading activities. Issue No. 03-11 addresses income statement classification of revenues related to derivatives that physically deliver and are not related to energy trading activities. Prior to Issue No. 03-11, there was no specific accounting guidance that addressed the classification in the income statement of Select Energy's retail marketing and wholesale contracts or the Utility Group's power supply contracts, many of which are non-trading derivatives.

On July 31, 2003, the EITF reached a consensus in Issue No. 03-11 that determining whether realized gains and losses on contracts that physically deliver and are not held for trading purposes should be reported on a net (sales and purchases both in expenses) or gross (sales in revenues and purchases in expenses) basis is a matter of judgment that depends on the relevant facts and circumstances. The EITF indicated that existing accounting guidance should be considered and provided no new guidance in Issue No. 03-11. In Issue No. 03-11, the EITF did not provide transition guidance, which management could have interpreted as becoming applicable on October 1, 2003 for revenues from that date forward. However, management applied its conclusion on net or gross reporting to all periods presented to enhance comparability.

Select Energy reports the settlement of long-term derivative contracts that physically deliver and are not held for trading purposes on a gross basis, generally with sales in revenues and purchases in expenses. Short-term sales and purchases represent power that is purchased to serve full requirements contracts but is ultimately not needed based on the actual load of the full requirements customers. This excess power is sold to the independent system operator or to other counterparties. For the years ended December 31, 2004 and 2003, settlements of short-term derivative contracts that are not held for trading purposes, are reported on a net basis in expenses.

The Utility Group reports the settlement of all short-term sales contracts that are part of procurement activities on a net basis in expenses.

On June 25, 2003, the DIG cleared Issue No. C-20, which addressed the meaning of "not clearly and closely related regarding contracts with a price adjustment feature" as it relates to the election of the normal purchase and sales exception to derivative accounting. The implementation of this guidance was required for the fourth quarter of 2003 for NU. The implementation of Issue No. C-20 resulted in CL&P recording the fair value of two existing power purchase contracts as derivatives, one as a derivative asset, and one as a derivative liability. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in rates.

Regulatory Accounting: The accounting policies of NU's regulated utility companies historically reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The transmission and distribution businesses of CL&P, PSNH and WMECO, along with PSNH's generation business and Yankee Gas' distribution business, continue to be cost-of-service rate regulated, and management believes the application of SFAS No. 71 to that portion of those businesses continues to be appropriate. Management must reaffirm this conclusion at each balance sheet date. If, as a result of a change in circumstances, it is determined that any portion of these companies no longer meets the criteria of regulatory accounting under SFAS No. 71, that portion of the company will have to discontinue regulatory accounting and write-off the respective regulatory assets and liabilities. Such a write-off could have a material impact on NU's consolidated financial statements.

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

Management uses its best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on NU's consolidated financial statements. Management believes it is probable that the Utility Group companies will recover the regulatory assets that have been recorded.

Goodwill and Other Intangible Assets: SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill balances be reviewed for impairment at least annually by applying a fair value-based test. NU selected October 1st as the annual goodwill impairment testing date. The goodwill impairment analysis impacts the Yankee Gas and the NU Enterprises segment. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount of the goodwill. If goodwill is deemed to be impaired it will be written-off to the extent it is impaired. This could have a significant impact on NU's consolidated financial statements.

NU has completed its impairment analyses as of October 1, 2004 for all reporting units that maintain goodwill and has determined that no impairments exist.

In performing the impairment evaluation required by SFAS No. 142, NU estimates the fair value of each reporting unit and compares it to the carrying amount of the reporting unit, including goodwill. NU estimates the fair values of its reporting units using discounted cash flow methodologies and an analysis of comparable companies or transactions. The discounted cash flow analysis requires the input of several critical assumptions, including future growth rates, operating cost escalation rates, allowed ROE, a risk-adjusted discount rate, and long-term earnings multiples of comparable companies. These assumptions are critical to the estimate and are susceptible to change from period to period.

Modifications to the aforementioned assumptions in future periods, particularly changes in discount rates, could result in future impairments of goodwill. Actual financial performance and market conditions in upcoming periods could also impact future impairment analyses.

Pension and Postretirement Benefits Other Than Pensions (PBOP): NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees. NU also participates in a postretirement benefit plan (PBOP Plan) to provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the resulting change in benefit obligations, fair values of plan assets, funded status and net periodic benefit credits or costs could have a material impact on NU's consolidated financial statements.

Results: Pre-tax periodic pension expense/income for the Pension Plan, excluding settlements, curtailments, and special termination benefits, totaled expense of $5.9 million, income of $31.8 million and income of $73.4 million for the years ended December 31, 2004, 2003 and 2002, respectively. The pension expense/income amounts exclude one-time items recorded under SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits."

As a result of litigation with nineteen former employees, in April 2004, NU was ordered by the court to modify its retirement plan to include special retirement benefits for fifteen of these former employees retroactive to the dates of their retirement and provide increased future monthly benefit payments. In the third quarter of 2004, NU withdrew its appeal of the court's ruling. As a result, NU recorded $2.1 million in special termination benefits related to this litigation in 2004.

There were no settlements, curtailments or special termination benefits recorded in 2003.

Net SFAS No. 88 items associated with early termination programs and the sale of the Millstone and Seabrook nuclear units totaled $22.2 million in income for the year ended December 31, 2002. This amount was recorded as a regulatory liability for refund to customers.

The pre-tax net PBOP Plan cost, excluding settlements, curtailments and special termination benefits, totaled $41.7 million, $35.1 million and $34.5 million for the years ended December 31, 2004, 2003 and 2002, respectively. The 2002 PBOP Plan cost excludes one-time items associated with the sale of the Seabrook nuclear units. These items totaled $1.2 million in income for the year ended December 31, 2002.

Long-Term Rate of Return Assumptions: In developing the expected long-term rate of return assumptions, NU evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU's historical 20-year compounded return of approximately 11 percent. NU's expected long-term rates of return on assets is based on certain target asset allocation assumptions and expected long-term rates of return. NU believes that 8.75 percent is a reasonable long-term rate of return on Pension Plan and PBOP Plan assets for 2004. NU will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rates of return assumptions by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	2004 and 2003		**2004** and 2003	
Asset Category	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity securities:				
United States	**45%**	**9.25%**	**55%**	**9.25%**
Non-United States	**14%**	**9.25%**	**11%**	**9.25%**
Emerging markets	**3%**	**10.25%**	**2%**	**10.25%**
Private	**8%**	**14.25%**	**—**	**—**
Debt Securities:				
Fixed income	**20%**	**5.50%**	**27%**	**5.50%**
High yield fixed income	**5%**	**7.50%**	**5%**	**7.50%**
Real estate	**5%**	**7.50%**	**—**	**—**

The actual asset allocations at December 31, 2004 and 2003 approximated these target asset allocations. NU regularly reviews the actual asset allocations and periodically rebalances the investments to the targeted asset allocations when appropriate. For information regarding actual asset allocations, see Note 4A, "Employee Benefits — Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Actuarial Determination of Income and Expense: NU bases the actuarial determination of Pension Plan and PBOP Plan income/expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. There will be no impact on the fair value of Pension Plan and PBOP Plan assets.

At December 31, 2004, the Pension Plan had cumulative unrecognized investment gains of $59 million, which will decrease pension expense over the next four years. At December 31, 2004, the Pension Plan had cumulative unrecognized actuarial losses of $413 million, which will increase pension expense over the expected future working lifetime of active Pension Plan participants, or approximately 13 years. The combined total of unrecognized investment gains and actuarial losses at December 31, 2004 is a net unrecognized loss of $354 million. These gains and losses impact the determination of pension expense and the actuarially determined prepaid pension amount recorded on the consolidated balance sheets but have no impact on expected Pension Plan funding.

At December 31, 2004, the PBOP Plan had cumulative unrecognized investment gains of $53 million, which will decrease PBOP Plan expense over the next four years. At December 31, 2004, the PBOP Plan also had cumulative unrecognized actuarial losses of $219 million, which will increase PBOP Plan expense over the expected future

working lifetime of active PBOP Plan participants, or approximately 13 years. The combined total of unrecognized investment gains and actuarial losses at December 31, 2004 is a net unrecognized loss of approximately $166 million. These gains and losses impact the determination of PBOP Plan cost and the actuarially determined accrued PBOP Plan cost recorded on the consolidated balance sheets.

Discount Rate: The discount rate that is utilized in determining future pension and PBOP obligations is based on a yield-curve approach where each cash flow related to the Pension or PBOP liability stream is discounted at an interest rate specifically applicable to the timing of the cash flow. The yield curve is developed from the top quartile of AA rated Moody's and S&P's bonds without callable features outstanding at December 31, 2004. This process calculates the present values of these cash flows and calculates the equivalent single discount rate that produces the same present value for future cash flows. The discount rates determined on this basis are 6.00 percent for the Pension Plan and 5.50 percent for the PBOP Plan at December 31, 2004. Discount rates used at December 31, 2003 were 6.25 percent for the Pension Plan and the PBOP Plan.

Expected Contribution and Forecasted Expense: Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on Pension Plan assets of 8.75 percent, a discount rate of 6.00 percent and an expected rate of return on PBOP assets of 6.85 percent for health assets, net of tax and 8.75 percent for life assets and non-taxable health assets, a discount rate of 5.50 percent and various other assumptions, NU estimates that expected contributions to and forecasted expense for the Pension Plan and PBOP Plan will be as follows (in millions):

	Pension Plan		Postretirement Plan	
Year	Expected Contributions	Forecasted Expense	Expected Contributions	Forecasted Expense
2005	$ —	$41.5	$50.3	$50.3
2006	$ —	$50.6	$46.8	$46.8
2007	$ —	$38.1	$39.4	$39.4

Future actual pension and postretirement expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plans and amounts capitalized.

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

	At December 31,			
	Pension Plan		Postretirement Plan	
Assumption Change	**2004**	2003	**2004**	2003
Lower long-term rate of return	**$10.0**	$10.7	**$0.7**	$0.9
Lower discount rate	**$13.4**	$12.3	**$1.0**	$1.0
Lower compensation increase	**$ (5.8)**	$ (5.9)	**N/A**	N/A

Plan Assets: The market-related value of the Pension Plan assets has increased from $1.9 billion at December 31, 2003 to $2.1 billion at December 31, 2004. The projected benefit obligation (PBO) for the Pension Plan has increased from $1.9 billion at December 31, 2003 to $2.1 billion at December 31, 2004. These changes have decreased the funded status of the Pension Plan on a PBO basis from an overfunded position of $3.8 million at December 31, 2003 to an underfunded position of $57.7 million at December 31, 2004. The PBO includes expectations of future employee compensation increases. The accumulated benefit obligation (ABO) of the Pension Plan was approximately $225 million less than Pension Plan assets at December 31, 2004 and approximately $240 million less than Pension Plan assets at December 31, 2003. The ABO is the obligation for employee service and compensation provided through December 31, 2004. If the ABO exceeds Pension Plan assets at a future plan measurement date, NU will record an additional minimum liability. NU has not made employer contributions since 1991.

The value of PBOP Plan assets has increased from $178 million at December 31, 2003 to $199.8 million at December 31, 2004. The benefit obligation for the PBOP Plan has increased from $405 million at December 31, 2003 to $468.3 million at December 31, 2004. These changes have increased the underfunded status of the PBOP Plan on an accumulated projected benefit obligation basis from $227 million at December 31, 2003 to $268.5 million at December 31, 2004. NU has made a contribution each year equal to the PBOP Plan's postretirement benefit cost, excluding curtailment, settlements and special termination benefits.

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 8 percent for 2004 and 9 percent for 2003, decreasing one percentage point per year to an ultimate rate of 5 percent in 2007. The effect of increasing the health care cost trend by one percentage point would have increased 2004 service and interest cost components of the PBOP Plan cost by $1 million in 2004 and $0.8 million in 2003.

Income Taxes: Income tax expense is calculated each year in each of the jurisdictions in which NU operates. This process involves estimating NU's actual current tax exposures as well as assessing temporary differences resulting from differing treatment of items, such as timing of the deduction and expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in NU's consolidated balance sheets. The income tax estimation process impacts all of NU's segments. Adjustments made to income taxes could significantly affect NU's consolidated financial statements. Management must also assess the likelihood that deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances.

NU accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." For temporary differences recorded as deferred tax liabilities that will be recovered in rates in the future, NU has established a regulatory asset. The regulatory asset amounted to $316.3 million and $253.8 million at December 31, 2004 and 2003, respectively. Regulatory agencies in certain jurisdictions in which NU's Utility Group companies operate require the tax effect of specific temporary differences to be "flowed through" to utility customers. Flow through treatment means that deferred tax expense is not recorded on the consolidated statements of income. Instead, the tax effect of the temporary difference impacts both amounts for income tax expense currently included in customers' rates and the company's net income. Flow through treatment can result in effective income tax rates that are significantly different than expected income tax rates. Recording deferred taxes on flow through items is required by SFAS No. 109, and the offset to the deferred tax amounts is the regulatory asset referred to above.

A reconciliation from expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in the accompanying footnotes to the consolidated financial statements. See Note 1H, "Summary of Significant Accounting Policies — Income Taxes," to the consolidated financial statements for further information.

The estimates that are made by management in order to record income tax expense, accrued taxes and deferred taxes are compared each year to the actual tax amounts filed on NU's income tax returns. The income tax returns were filed in the fall of 2004 for the 2003 tax year, and NU recorded differences between income tax expense, accrued taxes and deferred taxes on its consolidated financial statements and the amounts that were on its income tax returns.

Depreciation: Depreciation expense is calculated based on an asset's useful life, and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on NU's consolidated financial statements absent timely rate relief for Utility Group assets.

Accounting for Environmental Reserves: Environmental reserves are accrued using a probabilistic model approach when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to environmental liabilities could have a significant effect on earnings. The probabilistic model approach estimates the liability based on the most likely action plan from of a variety of available remediation options, ranging from no action to remedies ranging from establishing institutional controls to full site remediation and long-term monitoring. The probabilistic model approach estimates the liabilities associated with each possible action plan based on findings through various phases of site assessments. These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations and several cost estimates from outside engineering and remediation contractors. These amounts also take into consideration prior experience in remediating contaminated sites and data released by the United States Environmental Protection Agency and other organizations. These estimates are subjective in nature partly because there are usually several different remediation options from which to choose when working on a specific site. These estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations. The amounts recorded as environmental liabilities on the consolidated balance sheets represent management's best estimate of the liability for environmental costs based on current site information from site assessments and remediation estimates. These liabilities are estimated on an undiscounted basis.

Under current rate-making policy, PSNH and Yankee Gas have regulatory recovery mechanisms in place for environmental costs. Accordingly, regulatory assets have been recorded for certain of PSNH's and Yankee Gas' environmental liabilities. As of December 31, 2004 and 2003, $28 million and $26.3 million, respectively, have been recorded as regulatory assets on the accompanying consolidated balance sheets. CL&P recovers a certain level of environmental costs currently in rates but does not have an environmental cost recovery tracking mechanism. Accordingly, changes in CL&P's environmental reserves impact CL&P's earnings. WMECO does not have a regulatory mechanism to recover environmental costs from its customers, and changes in WMECO's environmental reserves impact WMECO's earnings.

Capital expenditures related to environmental matters are expected to total approximately $104 million in aggregate for the years 2005 through 2009. Of the $104 million, approximately $55 million relates to the conversion of a 50 megawatt oil and coal burning unit at Schiller Station to a wood burning unit to, among other things, provide a reduction in air emissions at the plant and approximately $14 million relates to installing equipment to meet emission requirements at HWP's Mt. Tom coal-fired generating station. The remainder primarily relates to other environmental remediation programs associated with NU's hydroelectric generation assets.

Asset Retirement Obligations: NU adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003. SFAS No. 143 requires that legal obligations associated with the retirement of property, plant and equipment be recorded as a liability on the balance sheet at fair value when incurred and when a reasonable estimate of the fair value can be made. SFAS No. 143 defines an asset retirement obligation (ARO) as a legal obligation that is required to be settled due to an existing or enacted law, statute, ordinance, or a written or oral promise to remove an asset. AROs may stem from environmental laws, state laws and regulations, easement agreements, building codes, contracts, franchise grants and agreements, oral promises made upon which third parties have relied, or the dismantlement, restoration, or reclamation of properties.

Upon adoption of SFAS No. 143, certain removal obligations were identified that management believes are AROs but either have not been incurred or are not material. These removal obligations arise in the ordinary course of business or have a low probability of occurring. The types of obligations primarily relate to transmission and distribution lines and poles, telecommunication towers, transmission cables and certain FERC or state regulatory agency re-licensing issues. There was

no impact to NU's earnings upon adoption of SFAS No. 143; however, if there are changes in certain laws and regulations, orders, interpretations or contracts entered into by NU, there may be future AROs that need to be recorded.

On June 17, 2004, the FASB issued the proposed interpretation, "Accounting for Conditional Asset Retirement Obligations." The proposed interpretation requires an entity to recognize a liability for the fair value of an ARO that is conditional on a future event if the liability's fair value can be reasonably estimated and clarifies that there are no circumstances in which a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation.

If adopted in its current form, there may be an impact to NU for AROs that NU currently concludes have not been incurred (conditional obligations). These conditional obligations may include utility poles and asbestos that, if removed or disturbed by construction or demolition, creates a disposal obligation. Management is in the process of evaluating the impact of the interpretation on NU.

Under SFAS No. 71, regulated utilities, including NU's Utility Group companies, currently recover amounts in rates for future costs of removal of plant assets. Future removals of assets do not represent legal obligations and are not AROs. Historically, these amounts were included as a component of accumulated depreciation until spent. At December 31, 2004 and 2003, these amounts totaling $328.8 million and $334 million, respectively, are classified as regulatory liabilities on the accompanying consolidated balance sheets.

Special Purpose Entities: In addition to SPEs that are described in the "Off-Balance Sheet Arrangements" section of this Management's Discussion and Analysis, during 2001 and 2002, to facilitate the issuance of rate reduction bonds and certificates intended to finance certain stranded costs, NU established four SPEs: CL&P Funding LLC, PSNH Funding LLC, PSNH Funding LLC 2, and WMECO Funding LLC (the funding companies). The funding companies were created as part of state-sponsored securitization programs. The funding companies are restricted from engaging in non-related activities and are required to operate in a manner intended to reduce the likelihood that they would be included in their respective parent company's bankruptcy estate if they ever become involved in a bankruptcy proceeding. The funding companies and the securitization amounts are consolidated in the accompanying consolidated financial statements.

During 1999, SESI established an SPE, HEC/Tobyhanna Energy Project, LLC (HEC/Tobyhanna), in connection with a federal energy savings performance project located at the United States Army Depot in Tobyhanna, Pennsylvania. HEC/Tobyhanna sold $26.5 million of Certificates related to the project and used the funds to repay SESI for the costs of the project. HEC/Tobyhanna's activities and Certificates are included in NU's consolidated financial statements.

Accounting Implications of NU Enterprises Comprehensive Business Review: The accounting for the business segments of NU Enterprises at December 31, 2004 assumed that those businesses are going concerns and will continue to be NU Enterprises' segments in the future. The comprehensive review of each of the NU Enterprises businesses resulted in decisions that changed the existing going concern accounting conclusions for certain of those businesses on March 9, 2005. The impacts of the decisions could be material and could include:

- The impairment of long-lived assets if they are no longer held and used and become held for sale at expected sales prices that are less than carrying values.
- The impairment of goodwill if expected cash flows that support the fair values of the reporting units that hold goodwill are reduced significantly by a change in business strategy or a decision to sell all or portions of the reporting units at prices less than carrying values.
- The impairment of intangible assets if expected cash flows that support them are reduced to below their carrying values.
- The recognition of closure costs such as severance, benefit plan curtailments, and lease termination payments.
- The recognition of losses associated with settling energy contracts currently accounted for on an accrual method of accounting that have negative fair values at the time of settlement.
- The termination of the normal purchase and sales exception to fair value accounting for derivatives and the resulting recognition of losses or gains on changes in fair value of the contracts since inception.

The methods of implementing the company's decision involving the wholesale marketing and services businesses are under review. Accordingly, management cannot determine the amounts of impairments or other losses.

For further information regarding the matters in this "Critical Accounting Policies and Estimates" section, see Note 1, "Summary of Significant Accounting Policies," Note 3, "Derivative Instruments," Note 4, "Employee Benefits," Note 5, "Goodwill and Other Intangible Assets," and Note 6B, "Commitments and Contingencies — Environmental Matters," to the consolidated financial statements.

Other Matters

Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 6, "Commitments and Contingencies," to the consolidated financial statements.

Contractual Obligations and Commercial Commitments: Information regarding NU's contractual obligations and commercial commitments at December 31, 2004 is summarized through 2009 and thereafter as follows:

(Millions of Dollars)	2005	2006	2007	2008	2009	Thereafter
Notes payable to banks (a)	$ 180.0	$ —	$ —	$ —	$ —	$ —
Long-term debt (a)	90.8	27.0	8.2	159.8	61.5	2,277.7
Estimated interest payments on existing debt	153.0	149.8	147.9	144.8	140.0	1,614.3
Capital leases (b)(c)	3.1	2.9	2.6	2.3	2.0	18.1
Operating leases (c)(d)	30.9	28.5	24.5	21.0	12.5	41.3
Required funding of other post-retirement benefit obligations	50.3	46.8	39.4	29.6	21.4	N/A
Long-term contractual arrangements (c)(d)	729.5	682.9	461.0	366.0	336.0	1,544.6
Select Energy purchase agreements (c)(d)(e)	4,940.1	650.8	156.4	99.0	85.6	261.1
Totals	$6,177.7	$1,588.7	$840.0	$822.5	$659.0	$5,757.1

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

(b) The capital lease obligations include imputed interest of $16.2 million.

(c) NU has no provisions in its capital or operating lease agreements or agreements related to its long-term contractual arrangements or Select Energy purchase commitments that could trigger a change in terms and conditions, such as acceleration of payment obligations.

(d) Amounts are not included on NU's consolidated balance sheets.

(e) Select Energy's purchase agreement amounts can exceed the amount expected to be reported in fuel, purchased and net interchange power because energy trading purchases are classified in revenues.

Rate reduction bond amounts are non-recourse to NU, have no required payments over the next five years and are not included in this table. The Utility Group's standard offer service contracts and default service contracts also are not included in this table. The estimated payments under interest rate swap agreements are not included in this table as the estimated payment amounts are not determinable. For further information regarding NU's contractual obligations and commercial commitments, see the Consolidated Statements of Capitalization and related footnotes, and Note 2, "Short-Term Debt," Note 6D, "Commitments and Contingencies — Long-Term Contractual Arrangements," and Note 9, "Leases," to the consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes statements concerning NU's expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In some cases the reader can identify these forward looking statements by words such as "estimate," "expect," "anticipate," "intend," "plan," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, expiration or initiation of significant energy supply contracts, changes in levels of capital expenditures, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, effectiveness of our risk management policies and procedures, changes in accounting standards and financial reporting regulations, fluctuations in the value of electricity positions, changes in the ability to sell electricity positions and close out natural gas positions at anticipated margins, obtaining new contracts at anticipated volumes and margins, terrorist attacks on domestic energy facilities and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the SEC. Management undertakes no obligation to update the information contained in any forward looking statements to reflect developments or circumstances occurring after the statement is made.

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

Results of Operations

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

Income Statement Variances	2004 over/(under) 2003		2003 over/(under) 2002	
(Millions of Dollars)	Amount	Percent	Amount	Percent
Operating Revenues	$617	10%	$ 832	16%
Operating Expenses:				
Fuel, purchased and net interchange power	496	13	686	23
Other operation	131	14	138	17
Maintenance	13	8	(24)	(12)
Depreciation	20	10	(1)	(1)
Amortization	(53)	(28)	(129)	(40)
Amortization of rate reduction bonds	12	8	5	3
Taxes other than income taxes	10	4	5	2
Gain on sale of utility plant	—	—	187	100
Total operating expenses	629	11	867	18
Operating Income	(12)	(3)	(35)	(8)
Interest expense, net	7	3	(24)	(9)
Other income/(loss), net	15	(a)	(44)	(a)
Income before income tax expense	(4)	(2)	(55)	(24)
Income tax expense	1	2	(24)	(32)
Preferred dividends of subsidiaries	—	—	—	—
Income before cumulative effect of accounting changes	(5)	(4)	(31)	(20)
Cumulative effect of accounting changes, net of tax benefits	5	100	(5)	(100)
Net income/(loss)	$ —	—%	$ (36)	(23)%

(a) Percent greater than 100.

Operating Revenues

Total revenues increased $617 million in 2004, compared with 2003, due to higher revenues from NU Enterprises ($387 million), higher electric distribution revenues ($172 million), higher gas distribution revenues ($46 million) and higher regulated transmission revenues ($13 million).

The NU Enterprises' revenue increase of $387 million is primarily due to higher revenues for the merchant retail energy business ($197 million), the 2003 revenue reduction recorded for the settlement of a wholesale power dispute associated with CL&P standard offer supply ($56 million), and an increased level of competitive energy services business ($42 million). Higher revenues for the merchant retail energy business resulted from higher electric volumes ($119 million), higher gas prices ($48 million), higher electric prices ($28 million), and higher gas volumes ($2 million). The competitive energy services business revenue increase resulted from higher revenues from a cogeneration project and higher volumes in the mechanical contracting group.

The electric distribution revenue increase of $172 million is primarily due to non-earnings components of CL&P, PSNH and WMECO retail rates ($141 million). The distribution component of these companies and the retail transmission component of CL&P and PSNH that flow through to earnings increased $33 million, primarily due to the CL&P retail transmission rate increase effective in January 2004. The non-earnings components increase of $141 million is primarily due to the pass through of energy supply costs ($269 million) and CL&P FMCC ($151 million), partially offset by the resolution of SMD cost recovery which was being collected from CL&P customers in 2003 and early 2004 and subsequently refunded beginning in late 2004 ($71 million), lower CL&P EAC revenue as a result of the end of EAC billings in 2003 ($44 million), lower transition cost recoveries for CL&P and WMECO ($44 million) and lower CL&P system benefit cost recoveries ($31 million). Regulated retail sales increased 0.9 percent in 2004 compared with 2003. On a weather adjusted basis, retail sales increased 1.9 percent as a result of improved economic conditions and increasing use per customer. In addition, electric wholesale revenues decreased $72 million, primarily due to lower Utility Group sales related to IPP contracts and the expiration of long-term contracts.

The higher gas distribution revenue of $46 million is primarily due to the increased recovery of gas costs ($17 million) and the absence of the 2003 unbilled revenue adjustment ($28 million).

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

Total revenues increased $832 million in 2003, compared with 2002, due to higher revenues from NU Enterprises ($588 million), higher Utility Group electric revenues ($165 million) and higher Utility Group gas revenues ($79 million).

The NU Enterprises' revenue increase of $588 million is primarily due to higher wholesale and retail requirements sales volumes ($386 million) and higher prices ($339 million).

The Utility Group revenue increase of $165 million is primarily due to higher retail electric revenue ($217 million), partially offset by lower wholesale revenue ($57 million). The regulated retail electric revenue increase is primarily due to higher CL&P recovery of incremental locational marginal pricing (LMP) costs net of amounts to be returned to customers ($72 million), higher sales volumes ($73 million), an adjustment to unbilled revenues ($46 million) and a higher average price resulting from the mix among customer classes for the regulated companies ($25 million). The higher Yankee Gas revenue is primarily due to higher recovery of gas costs ($81 million) and higher gas sales volumes ($26 million), partially offset by an adjustment to unbilled revenues ($28 million). Regulated retail electric kWh sales increased by 2.1 percent and firm natural gas sales increased by 7.8 percent in 2003, before the adjustments to unbilled revenues. The regulated wholesale revenue decrease is primarily due to lower PSNH 2003 sales as a result of the sale of Seabrook.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense increased $496 million in 2004, primarily due to higher wholesale costs at NU Enterprises ($224 million) and higher purchased power costs for the Utility Group ($272 million). The increase for the Utility Group is primarily due to an increase in the standard offer supply costs for CL&P ($152 million) and WMECO ($16 million), higher Yankee Gas expenses ($33 million) primarily due to increased gas prices, higher expenses for PSNH ($10 million) primarily due to higher energy and capacity purchases, partially offset by the 2003 CL&P recovery of certain fuel costs ($44 million).

Fuel, purchased and net interchange power expense increased $686 million in 2003, primarily due to higher wholesale energy purchases at NU Enterprises ($630 million) and higher gas costs ($77 million), partially offset by lower nuclear fuel ($20 million).

Other Operation

Other operation expenses increased $131 million in 2004, primarily due to higher expenses for NU Enterprises resulting from the increased volume in the contracting business ($71 million), higher CL&P RMR costs and other power pool related expenses ($71 million), higher PSNH fossil production expense ($6 million), and higher distribution expenses ($4 million), partially offset by lower C&LM expense ($20 million).

Other operation expense increased $138 million in 2003, primarily due to higher expenses for NU Enterprises resulting from service business growth ($59 million), higher regulated business administrative and general expenses primarily due to higher health care costs ($16 million), lower pension income ($31 million), higher RMR related transmission expense ($30 million), higher conservation and load management expenditures ($16 million), higher distribution expense ($6 million), and higher load and dispatch expenses ($6 million), partially offset by lower nuclear expense due to the sale of Seabrook ($29 million).

Maintenance

Maintenance expense increased $13 million in 2004, primarily due to higher expenses for NU Enterprises at its generating plants ($5 million), the absence of the 2003 positive resolution of the Millstone use of proceeds docket ($5 million) and higher electric distribution expenses ($5 million).

Maintenance expense decreased $24 million in 2003, primarily due to lower nuclear expense resulting from the sale of Seabrook ($26 million), partially offset by higher gas distribution expenses ($2 million).

Depreciation

Depreciation increased $20 million in 2004 due to higher Utility Group plant balances and higher depreciation rates at CL&P resulting from the distribution rate case decision effective in January 2004.

Depreciation decreased $1 million in 2003 primarily due to lower decommissioning and depreciation expenses resulting from 2002 depreciation of Seabrook as compared to no 2003 Seabrook-related depreciation ($7 million) and lower NU Enterprises depreciation due to a study which resulted in lengthening the useful lives of certain generation assets ($3 million), partially offset by higher Utility Group depreciation resulting from higher plant balances ($9 million).

Amortization

Amortization decreased $53 million in 2004 primarily due to lower Utility Group recovery of stranded costs and a decrease in amortization expense resulting from the amortization of GSC over-recoveries allowed in the CL&P distribution rate case effective in January 2004 ($29 million).

Amortization decreased $129 million in 2003 primarily due to the 2002 amortization of stranded costs upon the sale of Seabrook ($183 million), partially offset by higher amortization in 2003 related to the Utility Group's recovery of stranded costs ($62 million), in part resulting from higher wholesale revenue from the sale of IPP related energy.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $12 million in 2004 due to the repayment of a higher principal amount as compared to 2003.

Amortization of rate reduction bonds increased $5 million in 2003 due to the repayment of principal.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $10 million in 2004 primarily due to higher payroll taxes ($4 million), higher sales tax ($3 million) and higher local property taxes ($2 million).

Taxes other than income taxes increased $5 million in 2003, primarily due to a credit recorded in 2002 recognizing a Connecticut sales and use tax audit settlement ($8 million), partially offset by a lower 2003 payment to compensate the Town of Waterford for lost property tax revenue as a result of the sale of Millstone ($3 million) and lower New Hampshire property taxes due to the sale of Seabrook ($2 million).

Gain on Sale of Utility Plant

Gain on the sale of utility plant decreased $187 million in 2003 due to the gain recognized in 2002 resulting from CL&P's and North Atlantic Energy Corporation's (NAEC) sale of Seabrook ($187 million).

Interest Expense, Net

Interest expense, net increased $7 million in 2004 primarily due to the issuance of $75 million of ten-year notes at Yankee Gas in January 2004, the issuance of $50 million of thirty-year senior notes at WMECO in September 2004, and the issuance of $150 million of five-year notes at NU Parent in June 2003.

Interest expense, net decreased $24 million in 2003 primarily due to lower interest for the regulated subsidiaries resulting from lower rates ($12 million), lower interest at NU Parent as a result of the interest rate swap related to its $263 million fixed-rate senior notes ($8 million), capitalized interest on prepayments for generator interconnections ($4 million) and lower NAEC interest due to the retirement of debt ($3 million), partially offset by higher competitive business interest as a result of higher debt levels ($6 million).

Other Income/(Loss), Net

Other income/(loss), net increased $15 million in 2004 primarily due to the recognition, beginning in 2004, of a CL&P procurement fee approved in the TSO docket decision ($12 million).

Other (loss)/income, net decreased $44 million in 2003 primarily due to the 2002 elimination of certain reserves associated with NU's ownership share of Seabrook ($25 million), 2002 Seabrook related gains ($15 million), lower equity in earnings from the Yankee companies in 2003 ($7 million), a higher level of donations in 2003 ($5 million), RMS losses recorded in 2003 ($4 million) and lower 2003 conservation and load management incentive income ($2 million), partially offset by 2002 investment write-downs ($18 million).

Income Taxes

Included in the notes to the consolidated financial statements is a reconciliation of actual and expected tax expense. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions. In past years, this rate-making treatment has required the company to provide the customers with a portion of the tax benefits associated with accelerated tax depreciation in the year it is generated (flow-through depreciation). As these flow-through differences turn around, higher tax expense is recorded.

Income tax expense increased by $1 million in 2004 due to higher reversal of prior flow-through depreciation and lower favorable adjustments to tax expense, partially offset by lower state income tax expense, due to increased state tax credits and favorable unitary apportionment.

Income tax expense decreased by $24 million in 2003, primarily due to lower taxable income.

Cumulative Effect of Accounting Change, Net of Tax Benefit

A cumulative effect of accounting change, net of tax benefit ($5 million) was recorded in the third quarter of 2003 in connection with the adoption of FIN 46, which required NU to consolidate RMS into NU's financial statements and adjust its equity interest as a cumulative effect of an accounting change.

Company Report on Internal Controls Over Financial Reporting

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of Northeast Utilities and subsidiaries (NU) and of other sections of this annual report. These financial statements, which were audited by Deloitte & Touche LLP, have been prepared in conformity with accounting principles generally accepted in the United States of America using estimates and judgments, where required, and giving consideration to materiality.

Additionally, management is responsible for establishing and maintaining adequate internal controls over financial reporting. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, NU conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal control over financial reporting was ineffective as of December 31, 2004. Management identified a material weakness due to deficiencies in both the design and operating effectiveness of internal controls associated with the application of derivative accounting rules to certain wholesale natural gas contracts entered into by the wholesale marketing portion of NU Enterprises' merchant energy segment. NU filed a Form 8-K on January 26, 2005 to provide notice of the restatement of June 30, 2004 and September 30, 2004 reports on Form 10-Q due to this accounting error. Restatements amounted to an increase in net income of $1.1 million for the quarter ended June 30, 2004 and a decrease in net income of $47 million for the quarter ended September 30, 2004. Numerous account balances were affected by these material misstatements, primarily fuel, purchased and net interchange power, income tax expense, derivative assets, derivative liabilities, retained earnings, and accumulated other comprehensive income.

Accounting for derivative contracts is complex and requires a significant amount of judgment and interpretation of the rules. During the second and third quarters of 2004, management accounted for certain wholesale natural gas contracts using the accrual method of accounting. Using this method, changes in the fair value of the derivative contracts did not impact net income currently. As a result of further analysis performed through January 2005, management concluded that an error had been made in interpreting the derivative accounting rules. This misinterpretation led to a misapplication of the derivative accounting rules. These wholesale natural gas contracts should have been recorded at fair value with changes in fair value reflected currently in net income. The restatements discussed above were required in order to apply fair value accounting to these contracts. The material weakness occurred due to deficiencies in both the design and operating effectiveness of the internal control environment.

Management identified and is strengthening the effectiveness and design of internal controls related to this matter. During the first quarter of 2005, management is enhancing the effectiveness of internal controls by requiring additional documentation for each wholesale derivative transaction accounted for on an accrual basis. Management is also enhancing the design of internal controls, as follows. Accounting management will review and approve the accounting for all material transactions requiring accounting judgments. Accounting reporting relationships will be enhanced by having business unit controllers report to the corporate controller for accounting and financial reporting matters.

These control enhancements are being implemented in the first quarter of 2005. As a result, material misstatements in account balances and related disclosures associated with this material weakness are not expected in the future. However, until these controls or control enhancements are concluded to be operating effectively, management cannot determine if the material weakness described above will be eliminated.

This material weakness was discussed with the Audit Committee of the Board of Trustees and Deloitte & Touche LLP, our independent registered public accounting firm. Deloitte & Touche LLP has issued an attestation report on management's assessment of internal controls over financial reporting that can be found on the following page.

Reports of Independent Registered Public Accounting Firm

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited management's assessment, included in the accompanying Company Report on Internal Controls Over Financial Reporting, that Northeast Utilities and subsidiaries (the "Company") did not maintain effective internal control over financial reporting as of December 31, 2004, because of the effect of the material weakness identified in management's assessment based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

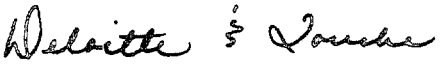
Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management's assessment: deficiencies existed in both the design and operating effectiveness of controls associated with the application of derivative accounting rules related to certain wholesale natural gas contracts entered into by the wholesale marketing portion of NU Enterprises' merchant energy segment. These deficiencies resulted in restatements of net income included in the Company's reports on Form 10-Q for June 30 and September 30, 2004 of $1.1 million and $47 million, respectively. Numerous account balances were affected by these material misstatements, primarily fuel, purchased and net interchange power, income tax expense, derivative assets, derivative liabilities, retained earnings, and accumulated other comprehensive income. Until these deficiencies are corrected, material misstatements in the account balances and related disclosures associated with this material weakness may occur. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2004, of the Company and this report does not affect our report on such financial statements.

In our opinion, management's assessment that the Company did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have not examined and, accordingly, we do not express an opinion or any other form of assurance on management's statements in the fourth and fifth paragraphs of the Company Report on Internal Controls Over Financial Reporting.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004, of the Company and our report dated March 16, 2005 expressed an unqualified opinion on those financial statements.



DELOITTE & TOUCHE LLP

Hartford, Connecticut
March 16, 2005

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities and subsidiaries (a Massachusetts Trust) (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, in 2003, the Company adopted Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities.

As discussed in Note 16, the Company has restated the consolidated balance sheet as of December 31, 2003 and the related consolidated statement of cash flows for the year then ended.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 16, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an adverse opinion on the effectiveness of the Company's internal control over financial reporting because of a material weakness.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Hartford, Connecticut
March 16, 2005

Consolidated Balance Sheets

(Thousands of Dollars)	At December 31, 2004	2003
Assets		(Restated)*
Current Assets:		
Cash and cash equivalents	$ 46,989	$ 43,372
Restricted cash — LMP costs	—	93,630
Special deposits	82,584	79,120
Investments in securitizable assets	139,391	166,465
Receivables, less provision for uncollectible accounts of $25,325 in 2004 and $40,846 in 2003	771,257	704,893
Unbilled revenues	144,438	125,881
Taxes receivable	61,420	—
Fuel, materials and supplies, at average cost	185,180	154,076
Derivative assets — current	81,567	116,305
Prepayments and other	154,395	63,780
	1,667,221	1,547,522
Property, Plant and Equipment:		
Electric utility	5,918,539	5,465,854
Gas utility	786,545	743,990
Competitive energy	918,183	885,953
Other	241,190	221,986
	7,864,457	7,317,783
Less: Accumulated depreciation	2,382,927	2,244,263
	5,481,530	5,073,520
Construction work in progress	382,631	356,396
	5,864,161	5,429,916
Deferred Debits and Other Assets:		
Regulatory assets	2,745,874	2,974,022
Goodwill	319,986	319,986
Purchased intangible assets, net	19,361	22,956
Prepaid pension	352,750	360,706
Prior spent nuclear fuel trust, at fair value	49,296	—
Derivative assets — long-term	198,769	132,812
Other	438,416	428,567
	4,124,452	4,239,049
Total Assets	$11,655,834	$11,216,487

* See Note 16.

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

Consolidated Balance Sheets

(Thousands of Dollars)	At December 31, 2004	2003
Liabilities and Capitalization		(Restated)*
Current Liabilities:		
Notes payable to banks	$ 180,000	$ 105,000
Long-term debt — current portion	90,759	64,936
Accounts payable	825,247	728,463
Accrued taxes	—	50,881
Accrued interest	49,449	41,653
Derivative liabilities — current	130,275	51,117
Counterparty deposits	57,650	46,496
Other	230,022	213,842
	1,563,402	1,302,388
Rate Reduction Bonds	1,546,490	1,729,960
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,434,403	1,277,309
Accumulated deferred investment tax credits	99,124	102,652
Deferred contractual obligations	413,056	469,218
Regulatory liabilities	1,069,842	1,164,288
Derivative liabilities — long-term	58,737	61,495
Other	267,895	247,526
	3,343,057	3,322,488
Capitalization:		
Long-Term Debt	2,789,974	2,481,331
Preferred Stock of Subsidiary — Non-Redeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value — authorized 225,000,000 shares; 151,230,981 shares issued and 129,034,442 shares outstanding in 2004 and 150,398,403 shares issued and 127,695,999 shares outstanding in 2003	756,155	751,992
Capital surplus, paid in	1,116,106	1,108,924
Deferred contribution plan — employee stock ownership plan	(60,547)	(73,694)
Retained earnings	845,343	808,932
Accumulated other comprehensive (loss)/income	(1,220)	25,991
Treasury stock, 19,580,065 shares in 2004 and 19,518,023 in 2003	(359,126)	(358,025)
Common Shareholders' Equity	2,296,711	2,264,120
Total Capitalization	5,202,885	4,861,651
Commitments and Contingencies (Note 6)		
Total Liabilities and Capitalization	$11,655,834	$11,216,487

* See Note 16.

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

Consolidated Statements of Income

(Thousands of Dollars, except share information)	For the Years Ended December 31, 2004	2003	2002
Operating Revenues	**$6,686,699**	$6,069,156	$5,237,000
Operating Expenses:			
Operation —			
Fuel, purchased and net interchange power	**4,231,192**	3,735,154	3,048,813
Other	**1,084,235**	953,026	815,212
Maintenance	**188,111**	174,703	198,725
Depreciation	**224,855**	204,388	205,646
Amortization	**138,271**	191,805	320,409
Amortization of rate reduction bonds	**164,915**	153,172	148,589
Taxes other than income taxes	**242,168**	232,672	227,518
Gain on sale of utility plant	**—**	—	(187,113)
Total operating expenses	**6,273,747**	5,644,920	4,777,799
Operating Income	**412,952**	424,236	459,201
Interest Expense:			
Interest on long-term debt	**139,853**	126,259	134,471
Interest on rate reduction bonds	**98,899**	108,359	115,791
Other interest	**14,762**	11,740	20,249
Interest expense, net	**253,514**	246,358	270,511
Other Income/(Loss), Net	**14,465**	(435)	43,828
Income Before Income Tax Expense	**173,903**	177,443	232,518
Income Tax Expense	**51,756**	50,732	74,850
Income Before Preferred Dividends of Subsidiary	**122,147**	126,711	157,668
Preferred Dividends of Subsidiary	**5,559**	5,559	5,559
Income Before Cumulative Effect of Accounting Change, Net of Tax Benefit	**116,588**	121,152	152,109
Cumulative effect of accounting change, net of tax benefit of $2,553 in 2003	**—**	(4,741)	—
Net Income	**$ 116,588**	$ 116,411	$ 152,109
Basic and Fully Diluted Earnings/(Loss) Per Common Share:			
Income before cumulative effect of accounting change, net of tax benefit	**$ 0.91**	$ 0.95	$ 1.18
Cumulative effect of accounting change, net of tax benefit	**—**	(0.04)	—
Basic and Fully Diluted Earnings Per Common Share	**$ 0.91**	$ 0.91	$ 1.18
Basic Common Shares Outstanding (weighted average)	**128,245,860**	127,114,743	129,150,549
Fully Diluted Common Shares Outstanding (weighted average)	**128,396,076**	127,240,724	129,341,360

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

Consolidated Statements of comprehensive Income

(Thousands of Dollars)	For the Years Ended December 31, 2004	2003	2002
Net Income	**$116,588**	$116,411	$152,109
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	**(28,246)**	9,274	52,360
Unrealized gains/(losses) on securities	**1,191**	2,093	(5,121)
Minimum supplemental executive retirement pension liability adjustments	**(156)**	(303)	158
Other comprehensive (loss)/income, net of tax	**(27,211)**	11,064	47,397
Comprehensive Income	**$ 89,377**	$127,475	$199,506

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

Consolidated Statements of Shareholders' Equity

(Thousands of Dollars, except share information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan — ESOP	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total
Balance as of January 1, 2002	130,132,136	$ 744,453	$ 1,107,609	$(101,809)	$ 678,460	$(32,470)	$ (278,603)	$ 2,117,640
Net income for 2002					152,109			152,109
Cash dividends on common shares — $0.525 per share					(67,793)			(67,793)
Issuance of common shares, $5 par value	485,207	2,426	5,032					7,458
Allocation of benefits — ESOP	607,475		(6,410)	14,063	2,835			10,488
Restricted shares, net	(11,887)		1,731				(151)	1,580
Repurchase of common shares	(3,650,900)						(58,734)	(58,734)
Capital stock expenses, net			376					376
Other comprehensive income						47,397		47,397
Balance as of December 31, 2002	127,562,031	746,879	1,108,338	(87,746)	765,611	14,927	(337,488)	2,210,521
Net income for 2003					116,411			116,411
Cash dividends on common shares — $0.575 per share					(73,090)			(73,090)
Issuance of common shares, $5 par value	1,022,556	5,113	8,541					13,654
Allocation of benefits — ESOP	607,020		(4,030)	14,052				10,022
Restricted shares, net	(7,508)		(4,110)				(99)	(4,209)
Repurchase of common shares	(1,638,100)						(23,210)	(23,210)
Issuance of treasury shares	150,000						2,772	2,772
Capital stock expenses, net			185					185
Other comprehensive income						11,064		11,064
Balance as of December 31, 2003	127,695,999	751,992	1,108,924	(73,694)	808,932	25,991	(358,025)	2,264,120
Net income for 2004					**116,588**			**116,588**
Cash dividends on common shares — $0.625 per share					**(80,177)**			**(80,177)**
Issuance of common shares, $5 par value	**832,578**	**4,163**	**6,774**					**10,937**
Allocation of benefits — ESOP	**567,907**		**(2,384)**	**13,147**				**10,763**
Restricted shares, net	**(62,042)**		**1,250**				**(1,101)**	**149**
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			**1,356**					**1,356**
Capital stock expenses, net			**186**					**186**
Other comprehensive income						**(27,211)**		**(27,211)**
Balance as of December 31, 2004	**129,034,442**	**$756,155**	**$1,116,106**	**$ (60,547)**	**$845,343**	**$ (1,220)**	**$(359,126)**	**$2,296,711**

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

Consolidated Statements of Cash Flows

(Thousands of Dollars)	For the Years Ended December 31, 2004	2003	2002
Operating Activities:		(Restated)*	
Income before preferred dividends of subsidiary	**$ 122,147**	$ 126,711	$ 157,668
Adjustments to reconcile to net cash flows provided by operating activities:			
Bad debt expense	**19,062**	23,229	16,590
Depreciation	**224,855**	204,388	205,646
Deferred income taxes and investment tax credits, net	**111,710**	(129,733)	(156,780)
Amortization	**138,271**	191,805	320,409
Amortization of rate reduction bonds	**164,915**	153,172	148,589
(Deferral)/amortization of recoverable energy costs	**(22,751)**	20,486	27,623
Gain on sale of utility plant	**—**	—	(187,113)
Pension expense/(income)	**10,636**	(16,416)	(47,192)
Cumulative effect of accounting change	**—**	(4,741)	—
Regulatory (refunds)/overrecoveries	**(150,119)**	287,974	27,061
Mark-to-market on natural gas contracts	**48,346**	—	—
Other sources of cash	**51,213**	20,002	94,039
Other uses of cash	**(114,210)**	(192,097)	(170,671)
Changes in current assets and liabilities:			
Restricted cash — LMP costs	**93,630**	(93,630)	—
Receivables and unbilled revenues, net	**(103,983)**	39,322	(118,771)
Fuel, materials and supplies	**(31,104)**	(34,223)	(27,590)
Investments in securitizable assets	**27,074**	12,443	27,459
Natural gas mark-to-market deposit	**(77,607)**	—	—
Other current assets	**(109,235)**	8,285	57,885
Accounts payable	**96,784**	(30,866)	166,298
Accrued taxes	**(50,880)**	(83,625)	107,134
Other current liabilities	**68,313**	90,928	(32,505)
Net cash flows provided by operating activities	**517,067**	593,414	615,779
Investing Activities:			
Investments in property and plant:			
Electric, gas and other utility plant	**(626,173)**	(545,917)	(489,528)
Competitive energy assets	**(17,649)**	(17,707)	(21,010)
Cash flows used for investments in property and plant	**(643,822)**	(563,624)	(510,538)
Investments in nuclear decommissioning trusts	**—**	—	(9,876)
Net proceeds from sale of utility plant	**—**	—	366,786
Buyout/buydown of IPP contracts	**—**	(20,437)	(5,152)
Investment in prior spent nuclear fuel trust	**(49,296)**	—	—
Payment for acquisitions, net of cash acquired	**—**	—	(16,351)
CVEC acquisition special deposit	**—**	(30,104)	—
Other investment activities	**23,131**	21,698	14,769
Net cash flows used in investing activities	**(669,987)**	(592,467)	(160,362)
Financing Activities:			
Issuance of common shares	**10,937**	13,654	7,458
Repurchase of common shares	**—**	(20,537)	(57,800)
Issuance of long-term debt	**512,762**	268,368	310,648
Issuance of rate reduction bonds	**—**	—	50,000
Retirement of rate reduction bonds	**(183,470)**	(169,352)	(169,039)
Increase/(decrease) in short-term debt	**75,000**	49,000	(234,500)
Reacquisitions and retirements of long-term debt	**(155,532)**	(65,600)	(314,773)
Cash dividends on preferred stock of subsidiaries	**(5,559)**	(5,559)	(5,559)
Cash dividends on common shares	**(80,177)**	(73,090)	(67,793)
Other financing activities	**(17,424)**	(4,792)	(736)
Net cash flows provided by/(used in) financing activities	**156,537**	(7,908)	(482,094)
Net increase/(decrease) in cash and cash equivalents	**3,617**	(6,961)	(26,677)
Cash and cash equivalents — beginning of period	**43,372**	50,333	77,010
Cash and cash equivalents — end of period	**$ 46,989**	$ 43,372	$ 50,333

* See Note 16.

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

Consolidated Statements of Capitalization

(Thousands of Dollars)		At December 31, 2004	2003
Common Shareholders' Equity		**$2,296,711**	$2,264,120
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption — $50 par value — authorized 9,000,000 shares in 2004 and 2003; 2,324,000 shares outstanding in 2004 and 2003; Dividend rates of $1.90 to $3.28: Current redemption prices of $50.50 to $54.00		**116,200**	116,200
Long-Term Debt:			
First Mortgage Bonds:			
Final Maturity	Interest Rates		
2005	5.00% to 6.75%	**57,500**	89,000
2009–2012	6.20% to 7.19%	**80,000**	80,000
2014	4.80% to 5.25%	**275,000**	—
2019–2024	7.88% to 10.07%	**209,845**	254,045
2026–2034	5.75% to 8.81%	**450,000**	320,000
Total First Mortgage Bonds		**1,072,345**	743,045
Other Long-Term Debt:			
Pollution Control Notes:			
2016–2018	5.90%	**25,400**	25,400
2021–2022	Adjustable Rate and 5.45% to 6.00%	**428,285**	428,285
2028	5.85% to 5.95%	**369,300**	369,300
2031	3.35% until 2008	**62,000**	62,000
Other:			
2005–2007	6.11% to 8.81%	**50,795**	76,249
2008	3.30%	**150,000**	150,000
2010–2015	5.00% to 9.24%	**328,694**	329,582
2018–2019	6.00% to 6.23%	**37,345**	38,476
2020–2022	6.23% to 7.63%	**41,581**	39,461
2024–2026	6.23% to 7.69%	**9,336**	35,532
2034	5.90%	**50,000**	—
Total Pollution Control Notes and Other		**$1,552,736**	$1,554,285
Total First Mortgage Bonds, Pollution Control Notes and Other		**2,625,081**	2,297,330
Fees and interest due for spent nuclear fuel disposal costs		**259,707**	256,438
Change in fair value		**91**	(3,577)
Unamortized premium and discount, net		**(4,146)**	(3,924)
Total Long-Term Debt		**2,880,733**	2,546,267
Less: Amounts due within one year		**90,759**	64,936
Long-Term Debt, Net		**2,789,974**	2,481,331
Total Capitalization		**$5,202,885**	$4,861,651

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

1. Summary of Significant Accounting Policies

A. About Northeast Utilities

Consolidated: Northeast Utilities (NU or the company) is the parent company of the companies comprising the Utility Group and NU Enterprises. NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) and is subject to the provisions of the 1935 Act. Arrangements among the Utility Group, NU Enterprises and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the Federal Energy Regulatory Commission (FERC) and/or the SEC. The Utility Group is subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions.

Several wholly owned subsidiaries of NU provide support services for NU's companies. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. Three other subsidiaries construct, acquire or lease some of the property and facilities used by NU's companies.

Utility Group: The Utility Group furnishes franchised retail electric service in Connecticut, New Hampshire and Massachusetts through three companies: The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH) and Western Massachusetts Electric Company (WMECO). Another company, North Atlantic Energy Corporation (NAEC), previously sold all of its entitlement to the capacity and output of the Seabrook nuclear unit (Seabrook) to PSNH under the terms of two, life-of-unit, full cost recovery contracts (Seabrook Power Contracts). Seabrook was sold on November 1, 2002. Another Utility Group subsidiary is Yankee Gas Services Company (Yankee Gas), which is Connecticut's largest natural gas distribution system. The Utility Group includes three reportable business segments: the regulated electric utility distribution segment, the regulated gas utility distribution segment and the regulated electric utility transmission segment.

Effective January 1, 2004, PSNH completed the purchase of the electric system and retail franchise of Connecticut Valley Electric Company (CVEC), a subsidiary of Central Vermont Public Service Corporation (CVPS), for $30.1 million. CVEC's 11,000 customers in western New Hampshire have been added to PSNH's customer base of more than 460,000 customers. The purchase price included the book value of CVEC's plant assets of approximately $9 million and an additional $21 million to terminate an above-market wholesale power purchase agreement CVEC had with CVPS. The $21 million payment is being recovered from PSNH's customers.

NU Enterprises: NU Enterprises, Inc. is the parent company of Northeast Generation Company (NGC), Northeast Generation Services Company (NGS), Select Energy, Inc. (Select Energy), Select Energy Services, Inc. (SESI) and their respective subsidiaries, and Woods Network Services, Inc. (Woods Network), all of which are collectively referred to as "NU Enterprises." The generation operations of Holyoke Water Power Company (HWP) are also included in the results of NU Enterprises.

The companies included in the NU Enterprises segment are grouped into two business segments: the merchant energy segment and the energy services business segment. The merchant energy business segment is comprised of Select Energy's wholesale marketing business, which includes approximately 1,296 megawatts (MW) of pumped storage and hydroelectric generation assets owned by NGC, 147 MW of coal-fired generation assets owned by HWP, and Select Energy's retail marketing business.

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

For information regarding NU's business segments, see Note 15, "Segment Information," to the consolidated financial statements.

B. Presentation

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

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

Subsequent to the filing of its 2003 Form 10-K and annual report, NU concluded that it incorrectly classified as unrestricted cash from counterparties amounts that should have been classified as cash and cash equivalents at December 31, 2003. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds were unrestricted and were used to fund or were available to fund the company's operations. The December 31, 2003 consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate intercompany derivative assets and liabilities. See Note 16, "Restatement of Previously Issued Financial Statements," to the consolidated financial statements for further information.

Additionally, certain reclassifications of prior year's data have been made to conform with the current year's presentation. See Note 16 for the effects of the significant reclassifications.

C. New Accounting Standards

Other-Than-Temporary Impairments: The Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued and later deferred the effective date of accounting guidance in EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and Its

Application to Certain Investments." EITF Issue No. 03-1 provides guidance on how to evaluate and recognize an impairment loss that is other-than-temporary and could impact NU's investments in Acumentrics Corporation (Acumentrics) and NEON Communications, Inc. (NEON) upon its effective date. Certain accounting guidance included in EITF Issue No. 03-1 is not effective until the FASB concludes on this issue. EITF Issue No. 03-1 also requires certain annual disclosures, which are included in this annual report.

For information regarding these disclosures see Note 1J, "Summary of Significant Accounting Policies - Other Investments" and Note 8, "Marketable Securities," to the consolidated financial statements.

Share-Based Payments: On December 16, 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004), "Share-Based Payments," (SFAS No. 123R), which amended SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123R requires all companies to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. NU has elected to apply SFAS No. 123R on a modified prospective method. Under this method, NU will recognize compensation expense for the unvested portion of previously granted awards that remain outstanding on July 1, 2005, the effective date of SFAS No. 123R, and any new awards after that date. NU is currently evaluating the impact of SFAS No. 123R, but management believes that the adoption of SFAS No. 123R will not have a material impact on NU's consolidated financial statements.

For further information regarding equity-based compensation, see Note 1N, "Equity-Based Compensation," to the consolidated financial statements.

Accounting for the Effect of Medicare Changes on Postretirement Benefits Other Than Pension (PBOP): On December 8, 2003, the President of the United States signed into law a bill that expands Medicare, primarily by adding a prescription drug benefit and by adding a federal subsidy to qualifying plan sponsors of retiree health care benefit plans. NU chose to reflect the impact on December 31, 2003 reported amounts with no impact on 2003 expenses, assets, or liabilities.

On May 19, 2004, the FASB issued Staff Position (FSP) No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to provide guidance on accounting for the effects of the aforementioned Medicare expansion. This FSP concludes that the effects of the federal subsidy should be considered an actuarial gain and treated like similar gains and losses and requires certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits which are included in this annual report. The accounting treatment under FSP No. FAS 106-2 is consistent with NU's accounting treatment at December 31, 2003 and reduced the projected benefit obligation by $7.5 million and $19.5 million in 2004 and 2003, respectively.

Consolidation of Variable Interest Entities: In December 2003, the FASB issued a revised version of FASB Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities," (FIN 46R). FIN 46R resulted in fewer NU investments meeting the definition of a variable interest entity (VIE). FIN 46R was effective for NU for the first quarter of 2004 and did not have an impact on NU's consolidated financial statements.

D. Guarantees

NU provides credit assurance in the form of guarantees and letters of credit in the normal course of business, primarily for the financial performance obligations of NU Enterprises. NU would be required to perform under these guarantees in the event of non-performance by NU Enterprises, primarily Select Energy. At December 31, 2004, the maximum level of exposure in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," under guarantees by NU, primarily on behalf of NU Enterprises, totaled $1.1 billion. A majority of these guarantees do not have established expiration dates. For the guarantees with expiration dates, most are due to expire by December 31, 2005. Additionally, NU had $48.9 million of letters of credit issued, of which $33.9 million were issued for the benefit of NU Enterprises at December 31, 2004.

At December 31, 2004, NU had outstanding guarantees on behalf of the Utility Group of $12.7 million. This amount is included in the total outstanding NU guarantee exposure amount of $1.1 billion.

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

NU currently has authorization from the SEC to provide up to $750 million of guarantees for NU Enterprises through June 30, 2007. The $12.7 million in guarantees to the Utility Group are subject to a separate $50 million SEC limitation apart from the current $750 million guarantee limit. The amount of guarantees outstanding for compliance with the SEC limit for NU Enterprises at December 31, 2004 is $358.6 million, which is calculated using different, more probabilistic and fair-value based criteria than the maximum level of exposure required to be disclosed under FIN 45. FIN 45 includes all exposures even though they are not reasonably likely to result in exposure to NU.

On October 19, 2004, the SEC authorized NU to issue guarantees of up to an aggregate $100 million through June 30, 2007 of the debt or other obligations of two of its subsidiaries, NUSCO and Rocky River Realty Company. These companies provide certain specialized support and real estate services and occasionally enter into transactions that require financial backing from NU parent. The amount of guarantees outstanding for compliance with the SEC limit under this category at December 31, 2004 is $0.2 million.

E. Revenues

Utility Group: Utility Group retail revenues are based on rates approved by the state regulatory commissions. These regulated rates are applied to customers' use of energy to calculate a bill. In general, rates can only be changed through formal proceedings with the state regulatory commissions.

Certain Utility Group companies utilize regulatory commission-approved tracking mechanisms to track the recovery of certain incurred costs. The tracking mechanisms allow for rates to be changed periodically, with overcollections refunded to customers or undercollections collected from customers in future periods.

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

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

In accordance with management's policy of testing the estimate of unbilled revenues twice each year using the cycle method of estimating unbilled revenues, testing was performed in the second and fourth quarters of 2004 but did not have a material impact on earnings. The cycle method uses the billed sales from each meter reading cycle and an estimate of unbilled days in each month based on the meter reading schedule. The cycle method is more accurate than the requirements method when used in a mostly weather-neutral month.

During 2003 the cycle method resulted in adjustments to the estimate of unbilled revenues that had a net positive after-tax earnings impact of approximately $4.6 million. The 2003 positive after-tax impacts on CL&P, PSNH, and WMECO were $7.2 million, $3.3 million, and $0.3 million, respectively. There was a negative after-tax impact on Yankee Gas of $6.2 million, including certain gas cost adjustments.

Utility Group Transmission Revenues: Wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU's wholesale transmission revenues are collected through a combination of the New England Regional Network Service (RNS) tariff and NU's Local Network Service (LNS) tariff. The RNS tariff, which is administered by the New England Independent System Operator, recovers the revenue requirements associated with transmission facilities that are deemed by the FERC to be regional facilities. This regional rate is reset on June 1st of each year. The LNS tariff provides for the recovery of NU's total transmission revenue requirements, net of revenues received from other sources, including those revenues received under RNS rates. NU's LNS tariff is also reset on June 1st of each year to coincide with the change in RNS rates. Additionally, NU's LNS tariff provides for a true-up to actual costs which ensures that NU recovers its total transmission revenue requirements, including an allowed ROE.

A significant portion of NU's transmission businesses' revenue is from charges to NU's distribution businesses. These distribution businesses recover these charges through rates charged to their retail customers. WMECO has a rate tracking mechanism to track transmission costs charged in distribution rates to the actual amount of transmission charges incurred. The 2004 rates set in the CL&P distribution rate case contained a level of transmission revenue sufficient to recover CL&P's anticipated 2004 transmission costs. The June 1, 2005 PSNH retail rate increase includes revenues to recover expected transmission costs. Neither CL&P nor PSNH have transmission cost tracking mechanisms.

NU Enterprises: NU Enterprises' revenues are recognized at different times for its different business lines. Wholesale and retail marketing revenues are recognized when energy is delivered. Trading revenues are recognized as the fair value of trading contracts changes. Service revenues are recognized as services are provided, often on a percentage of completion basis.

F. Derivative Accounting

SFAS Nos. 133 and 149: In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which amended SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 incorporated interpretations that were included in previous Derivative Implementation Group guidance, clarified certain conditions, and amended other existing pronouncements. It was effective for contracts entered into or modified after June 30, 2003. Management has determined that the adoption of SFAS No. 149 did not change NU's accounting for wholesale and retail marketing contracts, or the ability of NU Enterprises to elect the normal purchases and sales exception. The adoption of SFAS No. 149 resulted in fair value accounting for certain of Utility Group contracts that are subject to unplanned netting and do not meet the definition of capacity contracts. These non-trading derivative contracts are recorded at fair value as derivative assets and liabilities with offsetting amounts recorded as regulatory liabilities and assets because the contracts are part of providing regulated electric or gas service and because management believes that these amounts will be recovered or refunded in rates.

EITF Issue No. 03-11: In August of 2003, the FASB ratified the consensus reached by its EITF in July 2003 on EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-3." Prior to Issue No. 03-11, no specific guidance existed to address the classification in the income statement of derivative contracts that are not held for trading purposes. The consensus stated that determining whether realized gains and losses on contracts that physically deliver and are not held for trading purposes should be reported on a net or gross basis was a matter of judgment that depended on the relevant facts and circumstances. NU Enterprises and the Utility Group have derivative sales contracts, and though these contracts may result in physical delivery, management has determined, based on the relevant facts and circumstances, that because these transactions are part of the respective companies' procurement activities, inclusion in operating expenses better depicts these sales activities. At December 31, 2004, 2003 and 2002, the settlement of these derivative contracts that are not held for trading purposes are reported on a net basis in expenses.

In EITF Issue No. 03-11, the EITF did not provide transition guidance, which management could have interpreted as becoming applicable on October 1, 2003 for revenues from that date forward. However, management applied its conclusion on net or gross reporting to all periods presented to enhance comparability. Operating revenues and fuel, purchased and net interchange power for the years ended December 31, 2004, 2003 and 2002 reflect net reporting. The adoption of net reporting had no effect on net income.

Accounting for Energy Contracts: The accounting treatment for energy contracts entered into varies between contracts and depends on the intended use of the particular contract and on whether or not the contracts are derivatives.

Non-derivative contracts are recorded at the time of delivery or settlement.

Most of the contracts comprising Select Energy's wholesale and retail marketing activities are derivatives. The application of derivative accounting under SFAS No. 133, as amended, is complex and requires management's judgment. Judgment is applied in the election and designation of the normal purchases and sale exception (and resulting accounting upon delivery or settlement), which includes the conclusions that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accounting upon delivery or settlement would be terminated and fair value accounting would be applied.

Both long-term non-derivative contracts and long-term derivative contracts that are normal are recorded in revenues when these contracts represent sales, and recorded in fuel, purchased and net interchange power when these contracts represent purchases, except for sales contracts that relate to procurement activities. These contracts are recorded in fuel, purchased and net interchange power when settled.

Derivative contracts that are entered into for trading purposes are recorded on the consolidated balance sheets at fair value, and changes in fair value impact earnings. Revenues and expenses for these contracts are recorded on a net basis in revenues. Derivative contracts that are not held for trading purposes and that do not qualify as normal purchases and sales or hedges are non-trading derivative contracts. These contracts are recorded on the consolidated balance sheets at fair value, and changes in fair value for these contracts are recorded primarily in expenses.

Contracts that are hedging an underlying transaction and that qualify as cash flow hedges are recorded on the consolidated balance sheets at fair value with changes in fair value generally reflected in accumulated other comprehensive income. Hedges impact earnings when the forecasted transaction being hedged occurs, when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is no longer probable of occurring, or when there is an accumulated other comprehensive loss and when the hedge and the forecasted transaction being hedged are in a loss position on a combined basis.

For further information regarding these contracts and their accounting, see Note 3, "Derivative Instruments," to the consolidated financial statements.

G. Utility Group Regulatory Accounting

The accounting policies of NU's Utility Group conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution businesses of CL&P, PSNH and WMECO, along with PSNH's generation business and Yankee Gas' distribution business, continue to be cost-of-service rate regulated. New Hampshire's electric utility industry restructuring laws have been modified to delay the sale of PSNH's fossil and hydroelectric generation assets until at least April of 2006. There has been no regulatory action to the contrary, and management currently has no plans to divest of these generation assets. As the New Hampshire Public Utilities Commission (NHPUC) has allowed and is expected to continue to allow rate recovery of a return on and recovery of these assets, as well as all operating expenses, PSNH meets the criteria for the application of SFAS No. 71. Stranded costs related to generation assets, to the extent not currently recovered in rates, are deferred as Part 3 stranded costs under the "Agreement to Settle PSNH Restructuring" (Restructuring Settlement). Part 3 stranded costs are non-securitized regulatory assets that must be recovered by a recovery end date determined in accordance with the Restructuring Settlement or be written off.

Management believes the application of SFAS No. 71 to the portions of those businesses continues to be appropriate. Management also believes it is probable that NU's Utility Group companies will recover their investments in long-lived assets, including regulatory assets. In addition, all material net regulatory assets are earning an equity return, except for securitized regulatory assets, which are not supported by equity.

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

(Millions of Dollars)	At December 31, 2004	2003
Recoverable nuclear costs	**$ 52.0**	$ 82.4
Securitized assets	**1,537.4**	1,721.1
Income taxes, net	**316.3**	253.8
Unrecovered contractual obligations	**354.7**	378.6
Recoverable energy costs	**255.0**	255.7
Other	**230.5**	282.4
Totals	**$2,745.9**	$2,974.0

Additionally, the Utility Group had $11.6 million and $12.3 million of regulatory costs at December 31, 2004 and 2003, respectively, that are included in deferred debits and other assets — other on the accompanying consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved by the applicable regulatory agency. Management believes that these costs are recoverable in future rates.

Recoverable Nuclear Costs: In March of 2001, CL&P and WMECO sold their ownership interests in the Millstone nuclear units (Millstone). The gains on the sale in the amounts of approximately $521.6 million and $119.8 million, respectively, for CL&P and WMECO were used to offset recoverable nuclear costs. These unamortized recoverable nuclear costs amounted to $22.5 million at December 31, 2003, and were fully recovered by December 31, 2004. Additionally, PSNH recorded a regulatory asset in conjunction with the sale of Millstone 3 with an unamortized balance of $29.7 million and $33.3 million at December 31, 2004 and 2003, respectively, which is included in recoverable nuclear costs. Also included in recoverable nuclear costs for 2004 and 2003 are $22.3 million and $26.6 million, respectively, primarily related to Millstone 1 recoverable nuclear costs associated with the undepreciated plant and related assets at the time Millstone 1 was shutdown.

Securitized Assets: In March 2001, CL&P issued $1.4 billion in rate reduction certificates. CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with independent power producers (IPP). The unamortized CL&P securitized asset balance is $850 million and $960.5 million at December 31, 2004 and 2003, respectively. CL&P used the remaining proceeds from the issuance of the rate reduction certificates to securitize a portion of its SFAS No. 109, "Accounting for Income Taxes," regulatory asset. The securitized SFAS No. 109 regulatory asset had a balance remaining of $144.3 million and $163.2 million at December 31, 2004 and 2003, respectively.

In April 2001, PSNH issued rate reduction bonds in the amount of $525 million. PSNH used the majority of the proceeds from that issuance to buydown its power contracts with NAEC. The remaining PSNH securitized asset balance is $392.2 million and $427.5 million at December 31, 2004 and 2003, respectively.

In January 2002, PSNH issued an additional $50 million in rate reduction bonds and used the proceeds from that issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December 2001. The remaining PSNH securitized asset balance for the January 2002 issuance is $29.4 million and $37.9 million at December 31, 2004 and 2003, respectively.

In May 2001, WMECO issued $155 million in rate reduction certificates and used the majority of the proceeds from that issuance to buyout an IPP contract. The remaining WMECO securitized asset balance is $121.5 million and $132 million at December 31, 2004 and 2003, respectively.

Securitized assets are being recovered over the amortization period of their associated rate reduction certificates and bonds. All outstanding rate reduction certificates of CL&P are scheduled to amortize by December 30, 2010, while PSNH rate reduction bonds are scheduled to fully amortize by May 1, 2013, and WMECO rate reduction certificates are scheduled to fully amortize by June 1, 2013.

Income Taxes, Net: The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and SFAS No. 109. Differences in income taxes between SFAS No. 109 and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. For further information regarding income taxes, see Note 1H, "Summary of Significant Accounting Policies — Income Taxes," to the consolidated financial statements.

Unrecovered Contractual Obligations: CL&P, WMECO and PSNH, under the terms of contracts with the Yankee Companies, are responsible for their proportionate share of the remaining costs of the units, including decommissioning. These amounts are recorded as unrecovered contractual obligations. A portion of these obligations for CL&P was securitized in 2001 and is included in securitized regulatory assets. Amounts for PSNH are being recovered along with other stranded costs. See Note 6E, "Deferred Contractual Obligations" for additional information.

Recoverable Energy Costs: Under the Energy Policy Act of 1992 (Energy Act), CL&P, PSNH, WMECO, and NAEC were assessed for their proportionate shares of the costs of decontaminating and decommissioning uranium enrichment plants owned by the United States Department of Energy (DOE) (D&D Assessment). The Energy Act requires that regulators treat D&D Assessments as a reasonable and necessary current cost of fuel, to be fully recovered in rates like any other fuel cost. CL&P, PSNH and WMECO no longer own nuclear generation but continue to recover these costs through rates. At December 31, 2004 and 2003, NU's total D&D Assessment deferrals were $13.9 million and $18 million, respectively, and have been recorded as recoverable energy costs. Also included in recoverable energy costs at December 31, 2004, is $32.5 million related to federally mandated congestion charges. During 2003, CL&P paid for a temporary generation resource in southwest Connecticut to help maintain reliability. Costs for this resource of $15.8 million were recorded as recoverable energy costs at December 31, 2003.

In conjunction with the implementation of restructuring under the Restructuring Settlement on May 1, 2001, PSNH's fuel and purchased-power adjustment clause (FPPAC) was discontinued. At December 31, 2004 and 2003, PSNH had $144.8 million and $162.2 million, respectively, of recoverable energy costs deferred under the FPPAC. Under the Restructuring Settlement, the FPPAC deferrals are recovered as a Part 3 stranded cost through a stranded cost recovery charge. Also included in PSNH's recoverable energy costs are deferred costs associated with certain contractual purchases from IPPs. These costs are also treated as Part 3 stranded costs and amounted to $50.1 million and $56.1 million at December 31, 2004 and 2003, respectively.

The regulated rates of Yankee Gas include a purchased gas adjustment clause under which gas costs above or below base rate levels are charged to or credited to customers. Differences between the actual purchased gas costs and the current rate recovery are deferred and recovered or refunded in future periods. These amounts are recorded as recoverable energy costs of $13.7 million and $2.9 million at December 31, 2004 and 2003, respectively.

The majority of the recoverable energy costs are currently recovered in rates from the customers of CL&P, PSNH, WMECO, and Yankee Gas. PSNH's recoverable energy costs are Part 3 stranded costs which are non-securitized regulatory assets which must be recovered by a recovery end date determined in accordance with the Restructuring Settlement or be written off. Based on current projections, PSNH expects to fully recover all of its Part 3 costs by the recovery end date.

Regulatory Liabilities: The Utility Group had $1.1 billion and $1.2 billion of regulatory liabilities at December 31, 2004 and 2003, respectively. These amounts are comprised of the following:

(Millions of Dollars)	At December 31, 2004	2003
Cost of removal	**$ 328.8**	$ 334.0
CL&P CTA, GSC, and SBC overcollections	**200.0**	333.7
PSNH cumulative deferrals — SCRC	**208.6**	160.4
Regulatory liabilities offsetting Utility Group derivative assets	**191.4**	117.0
Other regulatory liabilities	**141.0**	219.2
Totals	**$1,069.8**	$1,164.3

Under SFAS No. 71, regulated utilities, including NU's Utility Group companies, currently recover amounts in rates for future costs of removal of plant assets. Historically, these amounts were included as a component of accumulated depreciation until spent. These amounts are classified as regulatory liabilities on the accompanying consolidated balance sheets in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations."

The Competitive Transition Assessment (CTA) allows CL&P to recover stranded costs, such as securitization costs associated with the rate reduction bonds, amortization of regulatory assets, and IPP over market costs while the Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for standard offer service. The System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes, and displaced workers protection costs. The Stranded Cost Recovery Charge (SCRC) allows PSNH to recover its stranded costs.

The regulatory liabilities offsetting derivative assets relate primarily to the fair value of CL&P IPP contracts and PSNH purchase and sales contracts used for market discovery of future procurement activities that will benefit ratepayers in the future.

H. Income Taxes

The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and SFAS No. 109.

Details of income tax expense are as follows:

(Thousands of Dollars)	For the Years Ended December 31, 2004	2003	2002
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	**$(53,531)**	$143,349	$197,426
State	**(6,422)**	37,116	34,204
Total current	**(59,953)**	180,465	231,630
Deferred income taxes, net			
Federal	**120,285**	(90,005)	(114,597)
State	**(4,768)**	(35,909)	(15,591)
Total deferred	**115,517**	(125,914)	(130,188)
Investment tax credits, net	**(3,808)**	(3,819)	(26,592)
Total income tax expense	**$ 51,756**	$ 50,732	$ 74,850
A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:			
Expected federal income tax	**$ 60,866**	$ 62,105	$ 81,381
Tax effect of differences:			
Depreciation	**5,805**	4,010	10,404
Amortization of regulatory assets	**1,795**	1,795	11,518
Investment tax credit amortization	**(3,808)**	(3,819)	(26,592)
State income taxes, net of federal benefit	**(5,377)**	785	12,098
Dividends received deduction	**(1,255)**	(1,370)	(3,237)
Tax asset valuation allowance/ reserve adjustments	**1,914**	(5,379)	(111)
Other, net	**(8,184)**	(7,395)	(10,611)
Total income tax expense	**$ 51,756**	$ 50,732	$ 74,850

NU and its subsidiaries file a consolidated federal income tax return. Likewise NU and its subsidiaries file state income tax returns, with some filing in more than one state. NU and its subsidiaries are parties to a tax allocation agreement under which taxable subsidiaries pay no more taxes than they would have otherwise paid had they filed a stand-alone tax return. Subsidiaries generating tax losses are similarly paid for their losses when utilized.

The tax effects of temporary differences that give rise to the current and long-term net accumulated deferred tax obligations are as follows:

(Millions of Dollars)	At December 31, 2004	2003
Deferred tax liabilities — current:		
Change in fair value of energy contracts	**$ 74.7**	$ 55.4
Other	**33.0**	22.1
Total deferred tax liabilities — current	**107.7**	77.5
Deferred tax assets — current:		
Change in fair value of energy contracts	**76.3**	59.1
Other	**14.7**	8.4
Total deferred tax assets — current	**91.0**	67.5
Net deferred tax liabilities — current	**16.7**	10.0
Deferred tax liabilities — long-term:		
Accelerated depreciation and other plant-related differences	**1,105.5**	904.4
Employee benefits	**169.2**	151.4
Regulatory amounts:		
Securitized contract termination costs and other	**252.1**	247.0
Income tax gross-up	**215.1**	178.6
Other	**239.8**	254.7
Total deferred tax liabilities — long-term	**1,981.7**	1,736.1
Deferred tax assets — long-term:		
Regulatory deferrals	**365.0**	341.5
Employee benefits	**86.7**	72.1
Income tax gross-up	**32.6**	20.8
Other	**63.0**	24.4
Total deferred tax assets — long-term	**547.3**	458.8
Net deferred tax liabilities — long-term	**1,434.4**	1,277.3
Net deferred tax liabilities	**$1,451.1**	$1,287.3

At December 31, 2004, NU had state net operating loss carry forwards of $206.2 million that expire between December 31, 2006 and December 31, 2024. At December 31, 2004, NU also had state credit carry forwards of $9.3 million that expire on December 31, 2009.

At December 31, 2003, NU had state net operating loss carry forwards of $119.5 million that expire between December 31, 2006 and December 31, 2023. The state net operating losses produced a deferred tax asset of $17.2 million and $10.4 million at December 31, 2004 and 2003, respectively.

NU had established a valuation allowance of $12.6 million and $9.4 million as of December 31, 2004 and 2003, respectively.

In 2000, NU requested from the Internal Revenue Service (IRS) a Private Letter Ruling (PLR) regarding the treatment of unamortized investment tax credits (ITC) and excess deferred income taxes (EDIT) related to generation assets that have been sold. EDIT are temporary differences between book and taxable income that were recorded when the federal statutory tax rate was higher than it is now or when those differences were expected to be resolved. The PLR addresses whether or not EDIT and ITC can be returned to customers, which without a PLR management believes would represent a violation of current tax law. The IRS declared a moratorium on issuing PLRs until final regulations on the return of EDIT and ITC to regulated customers are issued by the Treasury Department. Proposed regulations were issued in March 2003, and a hearing took place in June 2003. The proposed new regulations would allow the return of EDIT and ITC to regulated customers without violating the tax law. Also, under the proposed regulations, a company could elect to apply the regulation retroactively. The Treasury Department is currently

deliberating the comments received at the hearing. The ultimate results of this contingency could have a positive impact on CL&P's earnings.

I. Accounting for R.M. Services, Inc.

NU had an investment in R.M. Services, Inc. (RMS), a provider of consumer collection services. In January 2003, the FASB issued FIN 46, which was effective for NU on July 1, 2003. RMS is a VIE, as defined. FIN 46, as revised, requires that the party to a VIE that absorbs the majority of the VIE's losses, defined as the "primary beneficiary," consolidate the VIE. Upon adoption of FIN 46 on July 1, 2003, management determined that NU was the "primary beneficiary" of RMS under FIN 46 and that NU was now required to consolidate RMS into its financial statements. To consolidate RMS, NU eliminated the carrying value of its preferred stock investment in RMS and recorded the assets and liabilities of RMS. This adjustment resulted in a negative $4.7 million after-tax cumulative effect of an accounting change in the third quarter of 2003, and is summarized as follows (in millions of dollars):

Assets and Liabilities Recorded:	
Current assets	$0.6
Net property, plant and equipment	1.7
Other noncurrent assets	1.5
Current liabilities	(0.6)
	3.2
Elimination of investment at July 1, 2003	10.5
Pre-tax cumulative effect of accounting change	7.3
Income tax effect	(2.6)
Cumulative effect of accounting change	$4.7

Prior to the consolidation of RMS on July 1, 2003, NU recorded $1.4 million of pre-tax investment write-downs in 2003. After RMS was consolidated on July 1, 2003, $1.9 million of after-tax operating losses were included in earnings.

On June 30, 2004, RMS sold virtually all of its assets and liabilities for $3 million. NU recorded a gain totaling $0.8 million on the sale of RMS. Prior to the sale, RMS was consolidated into NU's financial statements and had after-tax operating losses totaling $1 million in 2004. These charges and gains are included in Note 1V, "Summary of Significant Accounting Policies — Other Income/(Loss)," and in the other segment in Note 15, "Segment Information," to the consolidated financial statements.

NU has no other VIE's for which it is defined as the "primary beneficiary."

J. Other Investments

At December 31, 2004 and 2003, NU maintained certain cost method and other investments. The cost method investments are comprised of NEON, a provider of optical networking services and Acumentrics, a developer of fuel cell and power quality equipment. Yankee Energy System, Inc. maintains the other investment, a long-term note receivable from BMC Energy LLC (BMC), an operator of renewable energy projects.

NEON: Under a 2002 common stock purchase agreement with NEON, NU invested $2.1 million in 2004 in exchange for an additional 341,000 shares of NEON common stock.

On July 19, 2004, NEON and Globix Corporation (Globix) announced a definitive merger agreement in which Globix, an unaffiliated publicly-owned entity, would acquire NEON for shares of Globix common stock. The merger closed on March 8, 2005, and NU received 1.2748 shares of Globix common stock for each of the 2.1 million shares of NEON stock it owned. Management calculated the estimated fair value of its investment in NEON based on the Globix share price at December 31, 2004 and the conversion factor. Results of the calculation indicated that the fair value of NU's investment in NEON was below the carrying value at December 31, 2004 and was impaired. As a result, NU recorded a pre-tax write-down of $2.2 million.

In 2002, NU recorded an investment write-down of $14.6 million on a pre-tax basis to reduce the carrying value of the investment in NEON to its net realizable value at that time. NU's investment in NEON had a carrying value of $9.8 million and $9.9 million at December 31, 2004 and 2003, respectively.

Acumentrics: Based on new information that affected the fair value of NU's investment in Acumentrics, management determined that the value of NU's investment declined in 2004 and that these declines were other-than-temporary in nature. Total investment write-downs of $9.1 million on a pre-tax basis were recorded in 2004 to reduce the carrying value of the investment. The balance of this investment at December 31, 2003 totaled $9.5 million including an investment in Acumentrics debt securities of $2 million. During 2004, NU invested an additional $0.2 million in Acumentrics debt securities. At December 31, 2004, after the investment write-downs, NU's remaining investment in Acumentrics totaled $0.6 million in debt securities.

BMC: In late-March 2004, based on revised information that impacted undiscounted cash flow projections and fair value estimates, management determined that the fair value of the note receivable from BMC had declined and that the note was impaired. As a result, management recorded an investment write-down of $2.5 million on a pre-tax basis in the first quarter of 2004. NU's remaining note receivable from BMC, which management expects to collect from BMC, totaled $1.3 million and $4 million at December 31, 2004 and 2003, respectively.

The NEON, Acumentrics and BMC investment write-downs are included in other income/(loss) on the accompanying consolidated statement of income. For further information regarding other income/(loss), see Note 1V, "Other Income/(Loss)" to the consolidated financial statements.

K. Depreciation

The provision for depreciation on utility assets is calculated using the straight-line method based on the estimated remaining useful lives of depreciable plant-in-service, which range primarily from 3 years to 75 years, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency where applicable. Depreciation rates are applied to plant-in-service from the time it is placed in service. When plant is retired from service, the original cost of the plant, including costs of removal less salvage, is charged to the accumulated provision for depreciation. Cost of removal is classified as a regulatory liability. The depreciation rates for the several classes of electric utility plant-in-service are equivalent to a composite rate of 3.3 percent in 2004, 3.4 percent in 2003 and 3.2 percent in 2002.

NU also maintains other non-utility plant which is being depreciated using the straight-line method based on their estimated remaining useful lives, which range primarily from 15 years to 120 years.

In 2002, NU Enterprises concluded a study of the depreciable lives of certain generation assets. The impact of this study was to lengthen the useful lives of those generation assets by 32 years to an average of 70 years. In addition, the useful lives of certain software was revised and shortened to reflect a remaining life of 1.5 years. Depreciation expense associated with these generation assets and software totaled $12.1 million in 2004, $14.2 million in 2003 and $17.7 million in 2002.

L. Jointly Owned Electric Utility Plant

Regional Nuclear Companies: At December 31, 2004, CL&P, PSNH and WMECO own common stock in three regional nuclear companies (Yankee Companies). NU's ownership interests in the Yankee Companies at December 31, 2004, which are accounted for on the equity method are 49 percent of the Connecticut Yankee Atomic Power Company (CYAPC), 38.5 percent of the Yankee Atomic Electric Company (YAEC) and 20 percent of the Maine Yankee Atomic Power Company (MYAPC). In 2003, CL&P, PSNH and WMECO sold their collective 17 percent ownership interest in Vermont Yankee Nuclear Power Corporation (VYNPC). NU's total equity investment in the Yankee Companies at December 31, 2004 and 2003, was $28.6 million and $32.2 million, respectively. Earnings related to these equity investments are included in other income/(loss) on the accompanying consolidated statements of income. For further information, see Note 1V, "Other Income/(Loss)," to the consolidated financial statements. Each of the remaining Yankee Companies owns a single nuclear generating plant which is being decommissioned.

NU owns 49 percent of the common stock of CYAPC with a carrying value of $21.4 million at December 31, 2004. CYAPC is involved in litigation over the termination of the decommissioning contract with Bechtel Power Corporation (Bechtel). Management believes that this litigation has not impaired the value of its investment in CYAPC at December 31, 2004 but will continue to evaluate the impact of the litigation on NU's investment. For further information regarding the Bechtel litigation, see Note 6E, "Commitments and Contingencies — Deferred Contractual Obligations," to the consolidated financial statements.

Hydro-Quebec: NU parent has a 22.66 percent equity ownership interest in two companies that transmit electricity imported from the Hydro-Quebec system in Canada. NU's investment and exposure to loss is $9.5 million and $10.1 million at December 31, 2004 and 2003, respectively.

M. Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of other interest expense and the cost of equity funds is recorded as other income on the consolidated statements of income as follows:

(Millions of Dollars, except percentages)	For the Years Ended December 31, 2004	2003	2002
Borrowed funds	**$4.5**	$ 5.0	$ 7.5
Equity funds	**3.8**	6.5	5.8
Totals	**$8.3**	$11.5	$13.3
Average AFUDC rate	**3.9%**	4.0%	4.9%

The average AFUDC rate is based on a FERC-prescribed formula that develops an average rate using the cost of the company's short-term financings as well as the company's capitalization (preferred stock, long-term debt and common equity). The average rate is applied to eligible construction work in progress amounts to calculate AFUDC.

N. Equity-Based Compensation

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

(Millions of Dollars, except per share amounts)	For the Years Ended December 31, 2004	2003	2002
Net income as reported	**$116.6**	$116.4	$152.1
Total equity-based employee compensation expense determined under the fair value-based method for all awards, net of related tax effects	**(1.1)**	(1.9)	(3.2)
Pro forma net income	**$115.5**	$114.5	$148.9
EPS:			
Basic and diluted — as reported	**$ 0.91**	$ 0.91	$ 1.18
Basic and diluted — pro forma	**$ 0.90**	$ 0.90	$ 1.15

Net income as reported includes $3.8 million, $2 million and $1 million of expense for restricted stock and restricted stock units for the years ended December 31, 2004, 2003 and 2002, respectively. NU accounts for restricted stock in accordance with APB No. 25 and amortizes the intrinsic value of the award over the related service period.

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

During the year ended December 31, 2004, no stock options were awarded.

Under SFAS No. 123R, NU will be required to recognize compensation expense for the unvested portion of previously granted awards that remain outstanding on July 1, 2005, the effective date of SFAS No. 123R, and any new awards after that date. Management believes that the impact of the adoption of SFAS No. 123R will not be material.

O. Sale of Receivables

Utility Group: At December 31, 2004 and 2003, CL&P had sold an undivided interest in its accounts receivable of $90 million and $80 million, respectively, to a financial institution with limited recourse through CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. CRC can sell up to $100 million of an undivided interest in its accounts receivable and unbilled revenues. At December 31, 2004 and 2003, the reserve requirements calculated in accordance with the Receivables Purchase and Sale Agreement were $18.8 million and

$29.3 million, respectively. These reserve amounts are deducted from the amount of receivables eligible for sale at the time. Concentrations of credit risk to the purchaser under this agreement with respect to the receivables are limited due to CL&P's diverse customer base within its service territory.

At December 31, 2004 and 2003, amounts sold to CRC by CL&P but not sold to the financial institution totaling $139.4 million and $166.5 million, respectively, are included in investments in securitizable assets on the accompanying consolidated balance sheets. These amounts would be excluded from CL&P's assets in the event of CL&P's bankruptcy. On July 7, 2004, CRC renewed its Receivables Purchase and Sale Agreement with CL&P and the financial institution through July 6, 2005, and the termination date of the facility was extended to July 3, 2007. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities — A Replacement of SFAS No. 125."

NU Enterprises: SESI has a master purchase agreement with an unaffiliated third party under which SESI may sell certain monies due or to become due under delivery orders issued pursuant to federal government energy savings performance contracts. The sale of a portion of the future cash flow from the energy savings performance contract is used to reimburse the costs to construct the energy savings projects. SESI continues to provide performance period services under the contract with the government for the remaining term. The portion of future government payments for performance period services is not sold to the fund or recorded as a receivable until such services are rendered.

At December 31, 2004, SESI had sold $30 million of accounts receivable related to the installation of the energy efficiency projects, with limited recourse, under this master purchase agreement. Under the delivery order with the government, SESI is responsible for on-going maintenance and other services related to the energy efficiency project installation. SESI receives payment for those services in addition to the amounts sold under the master purchase agreement. NU has provided a guarantee that SESI will perform its obligations under the master purchase agreement and subsequent individual assignment agreements. The sale of the receivables to the unaffiliated third party qualifies for sales treatment under SFAS No. 140, and therefore these receivables are not included in the consolidated financial statements.

In 2004, SESI entered into assignment agreements to sell an additional $26.5 million of receivables upon completion of the installation of the energy savings projects in 2005. Until the construction is completed, the receivables are recorded under the percentage of completion method and included in the consolidated financial statements and the advances under the purchase agreement are recorded as debt.

P. Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143. This statement requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. SFAS No. 143 was effective on January 1, 2003 for NU. Management has completed its review process for potential asset retirement obligations (ARO) and has not identified any material AROs that have been incurred. However, management has identified certain removal obligations that arise in the ordinary course of business or have a low probability of occurring. These types of obligations primarily relate to transmission and distribution lines and poles, telecommunication towers, transmission cables, and certain FERC or state regulatory agency re-licensing issues. These obligations are AROs that have not been incurred or are not material in nature.

On June 17, 2004, the FASB issued the proposed interpretation, "Accounting for Conditional Asset Retirement Obligations." The proposed interpretation requires an entity to recognize a liability for the fair value of an ARO that is conditional on a future event if the liability's fair value can be reasonably estimated and clarifies that there are no circumstances in which a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation.

If adopted in its current form, there may be an impact to NU for AROs that NU currently concludes have not been incurred (conditional obligations). These conditional obligations may include utility poles and asbestos that, if removed or disturbed by construction or demolition, creates a disposal obligation. Management is in the process of evaluating the impact of the interpretation on NU. The interpretation is scheduled to be issued in the first quarter of 2005 and would be effective for NU no later than December 31, 2005.

A portion of NU's regulated utilities' rates is intended to recover the cost of removal of certain utility assets. The amounts recovered do not represent AROs and are recorded as regulatory liabilities. At December 31, 2004 and 2003, cost of removal was approximately $328.8 million and $334 million, respectively.

Q. Materials and Supplies

Materials and supplies include materials purchased primarily for construction, operation and maintenance (O&M) purposes. Materials and supplies are valued at the lower of average cost or market.

R. Cash and Cash Equivalents

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

S. Special Deposits

Special deposits represent amounts Select Energy has on deposit with unaffiliated counterparties and brokerage firms in the amount of $46.3 million and amounts included in escrow for SESI that have not been spent on construction projects of $20 million at December 31, 2004. Similar amounts totaled $17 million and $32 million, respectively, at December 31, 2003. Special deposits at December 31, 2004 also included $16.3 million in escrow for Yankee Gas. The $16.3 million represents Yankee Gas' June 1, 2005 first mortgage bond payment. Special deposits at December 31, 2003 also included $30.1 million in escrow that PSNH funded to acquire CVEC on January 1, 2004.

T. Restricted Cash - LMP Costs

Restricted cash — LMP costs represents incremental locational marginal pricing (LMP) cost amounts that were collected by CL&P and deposited into an escrow account.

At December 31, 2003, restricted cash — LMP costs totaled $93.6 million, and an additional $30 million was deposited in 2004. During the third quarter of 2004, $83 million of the amount was paid to CL&P's standard offer suppliers in accordance with the FERC approved Standard Market Design (SMD) settlement. The remaining $41 million was released from the escrow account in the third quarter of 2004 and was refunded to CL&P's customers as a credit on bills from September to December of 2004.

U. Excise Taxes

Certain excise taxes levied by state or local governments are collected by NU from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. For the years ended December 31, 2004, 2003 and 2002, gross receipts taxes, franchise taxes and other excise taxes of $97 million, $96.8 million, and $88.8 million, respectively, are included in operating revenues and taxes other than income taxes on the accompanying consolidated statements of income.

V. Other Income/(Loss)

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

(Millions of Dollars)	For the Years Ended December 31, 2004	2003	2002
Other Income:			
Seabrook-related gains	$ —	$ —	$ 38.7
Investment income	16.5	17.1	25.4
CL&P procurement fee	11.7	—	—
AFUDC — equity funds	3.8	6.5	5.8
Gain on sale of RMS	0.8	—	—
Other	20.5	18.0	39.1
Total Other Income	53.3	41.6	109.0
Other Loss:			
Investment write-downs	(13.8)	(1.4)	(18.4)
Charitable donations	(3.8)	(8.4)	(3.7)
Costs not recoverable from regulated customers	(5.6)	(10.5)	(2.7)
Other	(15.6)	(21.7)	(40.4)
Total Other Loss	(38.8)	(42.0)	(65.2)
Totals	$ 14.5	$ (0.4)	$ 43.8

Investment income includes equity in earnings of regional nuclear generating and transmission companies of $2.6 million in 2004, $4.5 million in 2003 and $11.2 million in 2002. Equity in earnings relates to NU's investment in the Yankee Companies and the Hydro-Quebec system.

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

W. Supplemental Cash Flow Information

(Millions of Dollars)	For the Years Ended December 31, 2004	2003	2002
Cash paid during the year for:			
Interest, net of amounts capitalized	$227.7	$241.3	$259.9
Income taxes	$ 74.3	$248.3	$114.4

X. Marketable Securities

NU currently maintains two trusts that hold marketable securities. The trusts are used to fund NU's Supplemental Executive Retirement Plan (SERP) and WMECO's prior spent nuclear fuel liability. NU's marketable securities are classified as available-for-sale, as defined by SFAS No. 115, "Accounting for Certain Investments and Debt and Equity Securities." Unrealized gains and losses are reported as a component of accumulated other comprehensive income in the consolidated statements of shareholders' equity. Realized gains and losses are included in other income/(loss), in the consolidated statements of income.

For information regarding marketable securities, see Note 8, "Marketable Securities," to the consolidated financial statements.

Y. Counterparty Deposits

Balances collected from counterparties resulting from Select Energy's credit management activities totaled $57.7 million at December 31, 2004 and $46.5 million at December 31, 2003. These amounts are recorded as current liabilities and included as counterparty deposits on the accompanying consolidated balance sheets. To the extent Select Energy requires collateral from counterparties, cash is received as a part of the total collateral required. The right to receive such cash collateral in an unrestricted manner is determined by the terms of Select Energy's agreements. Key factors affecting the unrestricted status of a portion of this cash collateral include the financial standing of Select Energy and of NU as its credit supporter.

Z. Provision for Uncollectible Accounts

NU maintains a provision for uncollectible accounts to record its receivables at an estimated net realizable value. This provision is determined based upon a variety of factors, including applying an estimated uncollectible account percentage to each receivables aging category, historical collection and write-off experience and management's assessment of individual customer collectibility. Management reviews at least quarterly the collectibility of the receivables, and if circumstances change, collectibility estimates are adjusted accordingly. Receivable balances are written-off against the provision for uncollectible accounts when these balances are deemed to be uncollectible.

2. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by NU and its operating companies is subject to periodic approval by either the SEC under the 1935 Act or by the respective state regulators. On June 30, 2004, the SEC granted authorization allowing NU, CL&P, PSNH, WMECO, and Yankee Gas to incur total short-term borrowings up to a maximum of $450 million, $450 million, $100 million, $200 million, and $150 million, respectively, through June 30, 2007. The SEC also granted authorization for borrowing through the NU Money Pool (Pool).

The charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. At meetings in November 2003, CL&P obtained authorization from its stockholders to issue unsecured indebtedness with a maturity of less than 10 years in excess of the 10 percent of total capitalization limitation in CL&P's charter, provided that all unsecured indebtedness would not exceed 20 percent of total capitalization for a ten-year period expiring March 2014. On March 18, 2004, the SEC approved this change in CL&P's charter. As of December 31, 2004, CL&P is permitted to incur $394.8 million of additional unsecured debt.

PSNH is authorized by the NHPUC to incur short-term borrowings up to a maximum of $100 million.

Utility Group Credit Agreement: On November 8, 2004, CL&P, PSNH, WMECO, and Yankee Gas entered into a 5-year unsecured revolving credit facility for $400 million. This facility replaces a $300 million credit facility that expired on November 8, 2004. CL&P may draw up to $200 million, with PSNH, WMECO and Yankee Gas able to draw up to $100 million, subject to the $400 million maximum borrowing limit. Unless extended, the credit facility will expire on November 6, 2009. At December 31, 2004 and 2003, there were $80 million and $40 million, respectively, in borrowings under these credit facilities.

NU Parent Credit Agreement: On November 8, 2004, NU entered into a 5-year unsecured revolving credit and letter of credit (LOC) facility for $500 million. This facility replaces a $350 million 364-day facility that expired on November 8, 2004. This facility provides a total commitment of $500 million which is available for advances, subject to an LOC sub-limit. Subject to the advances outstanding, LOCs may be issued in notional amounts up to $350 million for periods up to 364 days. The agreement provides for LOCs to be issued in the name of NU or any of its subsidiaries. This total commitment may be increased to $600 million, subject to approval, at the request of the borrower. Unless extended, the credit facility will expire on November 6, 2009.

Current SEC authorization permits borrowings up to a maximum of $450 million. On November 20, 2004, an application was filed with the SEC requesting an increase of maximum borrowings to $500 million, to match this facility limit. At December 31, 2004 and 2003, there were $100 million and $65 million, respectively, in borrowings under these credit facilities. In addition, there were $48.9 million and $106.9 million in LOCs outstanding at December 31, 2004 and 2003, respectively.

Under the Utility Group and NU parent credit agreements, NU and its subsidiaries may borrow at fixed or variable rates plus an applicable margin based upon certain debt ratings, as rated by the lower of Standard and Poor's or Moody's Investors Service. The weighted average interest rates on NU's notes payable to banks outstanding on December 31, 2004 and 2003 were 4.53 percent and 2.07 percent, respectively.

Under the Utility Group and NU parent credit agreements, NU and its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including but not limited to, consolidated debt ratios and interest coverage ratios. The most restrictive financial covenant is the interest coverage ratio. The parties to the credit agreements currently are and expect to remain in compliance with these covenants.

Amounts outstanding under these credit facilities are classified as current liabilities as notes payable to banks on the accompanying consolidated balance sheets as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at any one time.

Other Credit Facility: On June 30, 2004, E.S. Boulos Company (Boulos), a subsidiary of NGS, renewed its $6 million line of credit. This credit facility replaces a similar credit facility that expired on June 30, 2004, and unless extended, will expire on June 30, 2005. This credit facility limits Boulos' ability to pay dividends if borrowings are outstanding and limits access to the Pool for additional borrowings. At December 31, 2004 and 2003, there were no borrowings under this credit facility.

3. Derivative Instruments

Derivatives that are utilized for trading purposes are recorded at fair value with changes in fair value included in earnings. Other contracts that are derivatives but do not meet the definition of a cash flow hedge and cannot be designated as being used for normal purchases or normal sales are also recorded at fair value with changes in fair value included in earnings. For those contracts that meet the definition of a derivative and meet the cash flow hedge requirements, the changes in the fair value of the effective portion of those contracts are generally recognized in accumulated other comprehensive income until the underlying transactions occur. For contracts that meet the definition of a derivative but do not meet the hedging requirements, and for the ineffective portion of contracts that meet the cash flow hedge requirements, the changes in fair value of those contracts are recognized currently in earnings. Derivative contracts designated as fair value hedges and the item they are hedging are both recorded at fair value on the consolidated balance sheets. Derivative contracts that are entered into as a normal purchase or sale and will result in physical delivery, and are documented as such, are recognized in revenue and expense when such deliveries occur.

For the year ended December 31, 2004, a negative $57.8 million, net of tax, was reclassified as an expense from other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized in earnings. Also during 2004, new cash flow hedge transactions were entered into that hedge cash flows through 2007. As a result of these new transactions and market value changes since January 1, 2004, accumulated other comprehensive income decreased by $28.3 million, net of tax. Accumulated other comprehensive income at December 31, 2004, was a negative $3.5 million, net of tax (decrease to equity), relating to hedged transactions, and it is estimated that a negative $2.9 million included in this net of tax balance will be reclassified as a decrease to earnings within the next twelve months. Cash flows from hedge contracts are reported in the same category as cash flows from the underlying hedged transaction.

There was a negative pre-tax impact of $0.5 million recognized in earnings for the ineffective portion of cash flow hedges. A negative pre-tax $0.6 million was recognized in 2004 earnings for the ineffective portion of fair value hedges. The changes in the fair value of both the fair value hedges and the natural gas inventory being hedged are recorded in fuel, purchased, and net interchange power on the accompanying consolidated statements of income.

The tables below summarize current and long-term derivative assets and liabilities at December 31, 2004 and December 31, 2003. The business activities of NU Enterprises that result in the recognition of derivative assets include concentrations of credit risk to energy marketing and trading counterparties. At December 31, 2004, Select Energy has $87.3 million of derivative assets from trading, non-trading, and hedging activities. These assets are exposed to counterparty credit risk. However, a significant portion of these assets is contracted with investment grade rated counterparties or collateralized with cash. The amounts below do not include option premiums paid, which are recorded as prepayments and amounted to $5.4 million and $9.1 million related to energy trading activities and $5.2 million and $7.6 million related to marketing activities at December 31, 2004 and December 31, 2003, respectively. These amounts also do not include option premiums paid of $18.7 million related to non-trading gas options at December 31, 2004.

The amounts below also do not include option premiums received, which are recorded as other current liabilities and amounted to $7 million and $12.2 million related to energy trading activities at December 31, 2004 and December 31, 2003, respectively, and $1.1 million related to marketing activities at December 31, 2004. Also not included at December 31, 2004, are option premiums received of $19 million related to non-trading gas options.

	At December 31, 2004				
	Assets		Liabilities		
(Millions in Dollars)	Current	Long-Term	Current	Long-Term	Net Total
NU Enterprises:					
Trading	$49.6	$ 31.7	$ (46.2)	$ (5.5)	$ 29.6
Non-trading	1.5	—	(70.5)	(9.6)	(78.6)
Hedging	4.5	—	(9.1)	(0.8)	(5.4)
Utility Group — Gas:					
Non-trading	0.2	—	(0.1)	—	0.1
Hedging	1.5	—	—	—	1.5
Utility Group — Electric:					
Non-trading	24.2	167.1	(4.4)	(42.8)	144.1
NU Parent: Hedging	0.1	—	—	—	0.1
Total	$81.6	$198.8	$(130.3)	$(58.7)	$ 91.4

	At December 31, 2003				
	Assets		Liabilities		
(Millions in Dollars)	Current	Long-Term	Current	Long-Term	Net Total
NU Enterprises:					
Trading	$ 40.0	$ 31.8	$(33.0)	$ (6.3)	$ 32.5
Non-trading	1.6	—	(0.8)	—	0.8
Hedging	54.6	1.2	(10.7)	(2.0)	43.1
Utility Group — Gas:					
Non-trading	0.2	—	(0.2)	—	—
Hedging	2.8	—	—	—	2.8
Utility Group — Electric:					
Non-trading	17.1	99.8	(6.4)	(49.6)	60.9
NU Parent: Hedging	—	—	—	(3.6)	(3.6)
Total	$116.3	$132.8	$(51.1)	$(61.5)	$136.5

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

Derivatives used in trading activities are recorded at fair value and included in the consolidated balance sheets as derivative assets or liabilities. Changes in fair value are recognized in operating revenues in the consolidated statements of income in the period of change. The net fair value positions of the trading portfolio at December 31, 2004 and 2003 were assets of $29.6 million and $32.5 million, respectively.

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

NU Enterprises — Non-Trading: Certain non-trading derivative contracts are used for delivery of energy related to Select Energy's wholesale and retail marketing activities. Changes in fair value of a negative $79.4 million of non-trading derivative contracts were recorded primarily in expenses in 2004. Of the $79.4 million change in fair value, $77.7 million relates to natural gas hedges at December 31, 2004. These hedges are used to mitigate the risk of electricity price changes on Select Energy's fixed-price electricity purchase contracts. These hedges do not meet criteria to be accounted for as cash flow hedges nor do they meet the normal purchase and sales exception and are accordingly accounted for at fair value as non-trading contracts. The contracts are natural gas contracts with fair values determined by prices provided by external sources and actively quoted markets. Select Energy held none of these contracts at December 31, 2003.

Market information for the TCCs classified as non-trading is not available, and those contracts cannot be reliably valued. Management believes the amounts paid for these contracts, which total $3.2 million at December 31, 2004, and $4.3 million at December 31, 2003 and are included in premiums paid, are equal to their fair value.

NU Enterprises — Hedging: Select Energy utilizes derivative financial and commodity instruments, including futures and forward contracts, to reduce market risk associated with fluctuations in the price of electricity and natural gas purchased to meet firm sales and purchase commitments to certain customers. Select Energy also utilizes derivatives, including price swap agreements, call and put option contracts, and futures and forward contracts to manage the market risk associated with a portion of its anticipated supply and delivery requirements. These derivatives have been designated as cash flow hedging instruments and are used to reduce the market risk associated with fluctuations in the price of electricity or natural gas. A derivative that hedges exposure to the variable cash flows of a forecasted transaction (a cash flow hedge) is initially recorded at fair value with changes in fair value recorded in accumulated other comprehensive income. Cash flow hedges impact net income when the forecasted transaction being hedged occurs, when hedge ineffectiveness is measured and recorded, when the forecasted transaction being hedged is no longer probable of occurring, or when there is accumulated other comprehensive loss and the hedge and the forecasted transaction being hedged are in a loss position on a combined basis.

Select Energy maintains natural gas service agreements with certain customers to supply gas at fixed prices for terms extending through 2006. Select Energy has hedged its gas supply risk under these agreements through NYMEX futures contracts. Under these contracts, which also extend through 2006, the purchase price of a specified quantity of gas is effectively fixed over the term of the gas service agreements. At December 31, 2004 the NYMEX futures contracts had notional values of $90.7 million and were recorded at fair value as derivative liabilities of $3.2 million.

Select Energy also maintains various physical and financial instruments to hedge its electric and gas purchases and sales through 2006. These instruments include forwards, futures, options, financial collars and swaps. These hedging contracts, which are valued at the mid-point of bid and ask market prices, were recorded as derivative assets of $3.7 million and derivative liabilities of $6.7 million at December 31, 2004.

Select Energy hedges certain amounts of natural gas inventory with gas futures, options and swaps, some of which are accounted for as fair value hedges. Changes in the fair value of hedging instruments and

natural gas inventory are recorded in earnings. The fair value of the futures, options and swaps were recorded as derivative assets of $0.8 million at December 31, 2004. The fair value of the hedged natural gas inventory was recorded as a reduction to fuel, materials and supplies of $1.5 million at December 31, 2004. For the year ended December 31, 2004, Select Energy recorded a negative pre-tax of $0.6 million in earnings related to its hedging instruments and natural gas inventory. In 2004, certain of these fair value hedges were redesignated as cash flow hedges, and future changes in fair value during the hedge designation will be included in other comprehensive income (equity), unless ineffective.

Utility Group – Gas – Non-Trading: Yankee Gas' non-trading derivatives consist of peaking supply arrangements to serve winter load obligations and firm sales contracts with options to curtail delivery. These contracts are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined, because of the optionality in the contract terms. Non-trading derivatives at December 31, 2004 included assets of $0.2 million and liabilities of $0.1 million.

Utility Group – Gas – Hedging: Yankee Gas maintains a master swap agreement with a financial counterparty to purchase gas at fixed prices. Under this master swap agreement, the purchase price of a specified quantity of gas for an unaffiliated customer is effectively fixed over the term of the gas service agreements with that customer for a period not extending beyond 2005. At December 31, 2004, the commodity swap agreement had a notional value of $2.3 million and was recorded at fair value as a derivative asset of $1.5 million. The firm commitment contract that is hedged is also recorded as a liability on the accompanying consolidated balance sheets, and changes in fair values of the hedge and firm commitment have offsetting impacts in earnings.

Utility Group – Electric – Non-Trading: CL&P has two IPP contracts to purchase power that contain pricing provisions that are not clearly and closely related to the price of power and therefore do not qualify for the normal purchases and sales exception. The fair values of these IPP non-trading derivatives at December 31, 2004 include a derivative asset with a fair value of $191.3 million and a derivative liability with a fair value of $47.2 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of the stranded costs, and management believes that these costs will continue to be recovered or refunded in rates.

NU Parent – Hedging: In March of 2003, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate note that matures on April 1, 2012. As a matched-terms fair value hedge, the changes in fair value of the swap and the hedged debt instrument are recorded on the consolidated balance sheets but are equal and offsetting in the consolidated statements of income. The cumulative change in the fair value of the hedged debt of $0.1 million is included as an increase to long-term debt on the consolidated balance sheets. The hedge is recorded as a derivative asset of $0.1 million. The resulting changes in interest payments made are recorded as adjustments to interest expense.

4. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

Pension Benefits: NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. Pre-tax pension expense/(income) was expense of $5.9 million in 2004, income of $31.8 million in 2003, and income of $73.4 million in 2002. These amounts exclude pension settlements, curtailments and net special termination benefit expense of $2.1 million in 2004 and income of $22.2 million in 2002. NU uses a December 31 measurement date for the Pension Plan. Pension (income)/expense attributable to earnings is as follows:

	For Years Ended December 31,		
(Millions of Dollars)	**2004**	2003	2002
Pension expense/(income) before settlements, curtailments and special termination benefits	**$ 5.9**	$(31.8)	$(73.4)
Pension income capitalized as utility plant	**2.6**	15.4	26.2
Net pension expense/(income) before settlements, curtailments, and special termination benefits	**8.5**	(16.4)	(47.2)
Settlements, curtailments, and special termination benefits reflected in earnings	**2.1**	—	—
Total pension expense/(income) included in earnings	**$10.6**	$(16.4)	$(47.2)

Pension Settlements, Curtailments and Special Termination Benefits: As a result of litigation with nineteen former employees, in April 2004, NU was ordered by the court to modify its retirement plan to include special retirement benefits for fifteen of these former employees retroactive to the dates of their retirement and increased future monthly benefit payments. In the third quarter of 2004, NU withdrew its appeal of the court's ruling. As a result, NU recorded $2.1 million in special termination benefits related to this litigation in 2004. NU made a lump sum benefit payment totaling $1.5 million to these former employees.

There were no settlements, curtailments or special termination benefits in 2003 and none in 2002 that impacted earnings.

On November 1, 2002, CL&P, NAEC and certain other joint owners consummated the sale of their ownership interests in Seabrook to a subsidiary of FPL Group, Inc. (FPL) and North Atlantic Energy Service Corporation (NAESCO), a wholly owned subsidiary of NU, ceased having operational responsibility for Seabrook at that time. NAESCO employees were transferred to FPL, which significantly reduced the expected service lives of NAESCO employees who participated in the Pension Plan. As a result, NAESCO recorded pension curtailment income of $29.1 million in 2002. As the curtailment related to the operation of Seabrook, NAESCO credited the joint owners of Seabrook with this amount. CL&P recorded its $1.2 million share of this income as a reduction to stranded costs, and as such, there was no impact on 2002 CL&P earnings. PSNH was credited with its $10.5 million share of this income through the Seabrook Power Contracts with NAEC. PSNH also credited this income as a reduction to stranded costs, and as such, there was no impact on 2002 PSNH earnings.

Additionally, in conjunction with the divestiture of its generation assets, NU recorded $1.2 million in curtailment income in 2002, all of which was recorded as a regulatory liability and did not impact earnings.

Effective February 1, 2002, certain CL&P and Utility Group employees who were displaced were eligible for a Voluntary Retirement Program (VRP). The VRP supplements the Pension Plan and provides special provisions. Eligible employees include non-bargaining unit employees or employees belonging to a collective bargaining unit that has agreed to accept the VRP who are active participants in the Pension Plan at January 1, 2002, and that have been displaced as part of the reorganization between January 22, 2002 and March 2003. Eligible employees received a special retirement benefit under the VRP whose value was roughly equivalent to a multiple of base pay based on years of credited service. During 2002, NU recorded an expense of $8.1 million associated with special pension termination benefits related to the VRP. NU believes that the cost of the VRP is probable of recovery through regulated utility rates, and accordingly, the $8.1 million was recorded as a regulatory asset with no impact on 2002 earnings.

Market-Related Value of Pension Plan Assets: NU bases the actuarial determination of pension plan income or expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Postretirement Benefits Other Than Pensions: NU's subsidiaries also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees (PBOP Plan). These benefits are available for employees retiring from NU who have met specified service requirements. For current employees and certain retirees, the total benefit is limited to two times the 1993 per retiree health care cost. These costs are charged to expense over the estimated work life of the employee. NU uses a December 31st measurement date for the PBOP Plan.

NU annually funds postretirement costs through external trusts with amounts that have been rate-recovered and which also are tax deductible. Currently, there are no pending regulatory actions regarding postretirement benefit costs and there are no postretirement benefit costs that are deferred as regulatory assets.

Impact of New Medicare Changes on PBOP: On December 8, 2003, the President signed into law a bill that expands Medicare, primarily by adding a prescription drug benefit starting in 2006 for Medicare-eligible retirees as well as a federal subsidy to plan sponsors of retiree health care benefit plans who provide a prescription drug benefit at least actuarially equivalent to the new Medicare benefit.

Based on the current PBOP Plan provisions, NU's actuaries believe that NU will qualify for this federal subsidy because the actuarial value of NU's PBOP Plan is estimated to be 60 percent greater than that of the standard Medicare benefit. NU will directly benefit from the federal subsidy for retirees of PSNH and NAESCO who retired before 1993, and other NU retirees who retired before 1991. For other retirees, management does not believe that NU will benefit from the subsidy because NU's cost support for these retirees is capped at a fixed dollar commitment.

Based on the most recent actuarial valuation as of January 1, 2004, the impact of the Medicare program has been revised from a $19.5 million decrease in the PBOP benefit obligation at December 31, 2003 to $27 million at January 1, 2004. The total $27 million decrease consists of $20 million as a direct result of the subsidy for certain non-capped retirees and $7 million related to changes in participation assumptions for capped retirees and future retirees as a result of the subsidy. The total $27 million decrease is currently being amortized as a reduction to PBOP expense over approximately 13 years. For the year ended December 31, 2004, this reduction in PBOP expense totaled approximately $3.6 million, including amortization of the actuarial gain of $2 million and a reduction in interest cost and service cost based on a lower PBOP benefit obligation of $1.6 million.

PBOP Settlements, Curtailments and Special Termination Benefits: There were no settlements, curtailments or special termination benefits in 2004 or 2003.

In 2002, NU recorded PBOP special termination benefits income of $1.2 million related to the sale of Seabrook. CL&P and PSNH recorded their shares of this curtailment as reductions to stranded costs.

The following table represents information on the plans' benefit obligation, fair value of plan assets, and the respective plans' funded status:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2004**	2003	**2004**	2003
Change in benefit obligation				
Benefit obligation at beginning of year	**$(1,941.3)**	$(1,789.8)	**$(405.0)**	$(397.8)
Service cost	**(40.7)**	(35.1)	**(6.0)**	(5.3)
Interest cost	**(118.9)**	(117.0)	**(25.3)**	(26.8)
Medicare prescription drug benefit impact	**N/A**	N/A	**—**	19.5
Actuarial loss	**(136.7)**	(102.9)	**(68.7)**	(34.8)
Benefits paid — excluding lump sum payments	**105.0**	99.6	**36.7**	40.2
Benefits paid — lump sum payments	**1.5**	3.9	**—**	—
Special termination benefits	**(2.1)**	—	**—**	—
Benefit obligation at end of year	**$(2,133.2)**	$(1,941.3)	**$(468.3)**	$(405.0)
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,945.1**	$ 1,632.3	**$ 178.0**	$ 147.7
Actual return on plan assets	**236.9**	416.3	**16.8**	35.4
Employer contribution	**—**	—	**41.7**	35.1
Benefits paid — excluding lump sum payments	**(105.0)**	(99.6)	**(36.7)**	(40.2)
Benefits paid — lump sum payments	**(1.5)**	(3.9)	**—**	—
Fair value of plan assets at end of year	**$ 2,075.5**	$ 1,945.1	**$ 199.8**	$ 178.0
Funded status at December 31	**$ (57.7)**	$ 3.8	**$(268.5)**	$(227.0)
Unrecognized transition obligation/(asset)	**0.4**	(1.1)	**94.8**	106.6
Unrecognized prior service cost	**56.3**	63.5	**(5.2)**	(5.5)
Unrecognized net loss	**353.7**	294.5	**166.5**	113.6
Prepaid/(accrued) benefit cost	**$ 352.7**	$ 360.7	**$ (12.4)**	$ (12.3)

The accumulated benefit obligation for the Plan was $1.9 billion and $1.7 billion at December 31, 2004 and 2003, respectively.

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Balance Sheets	**2004**	2003	**2004**	2003
Discount rate	**6.00%**	6.25%	**5.50%**	6.25%
Compensation/progression rate	**4.00%**	3.75%	**N/A**	N/A
Health care cost trend rate	**N/A**	N/A	**8.00%**	9.00%

The components of net periodic (income)/expense are as follows:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2004**	2003	2002	**2004**	2003	2002
Service cost	**$ 40.7**	$ 35.1	$ 37.2	**$ 6.0**	$ 5.3	$ 6.2
Interest cost	**118.9**	117.0	119.8	**25.3**	26.8	29.2
Expected return on plan assets	**(175.1)**	(182.5)	(204.9)	**(12.5)**	(14.9)	(16.6)
Amortization of unrecognized net transition (asset)/obligation	**(1.5)**	(1.5)	(1.4)	**11.9**	11.9	13.6
Amortization of prior service cost	**7.2**	7.2	7.7	**(0.4)**	(0.4)	(0.1)
Amortization of actuarial loss/(gain)	**15.7**	(7.1)	(31.8)	**—**	—	—
Other amortization, net	**—**	—	—	**11.4**	6.4	2.2
Net periodic expense/(income) — before curtailments and special termination benefits	**5.9**	(31.8)	(73.4)	**41.7**	35.1	34.5
Curtailment income	**—**	—	(30.3)	**—**	—	—
Special termination benefits expense/(income)	**2.1**	—	8.1	**—**	—	(1.2)
Total curtailments and special termination benefits	**2.1**	—	(22.2)	**—**	—	(1.2)
Total — net periodic expense/(income)	**$ 8.0**	$(31.8)	$(95.6)	**$41.7**	$35.1	$33.3

For calculating pension and postretirement benefit income and expense amounts, the following assumptions were used:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
Statements of Income	**2004**	2003	2002	**2004**	2003	2002
Discount rate	**6.25%**	6.75%	7.25%	**6.25%**	6.75%	7.25%
Expected long-term rate of return	**8.75%**	8.75%	9.25%	**N/A**	N/A	N/A
Compensation/progression rate	**3.75%**	4.00%	4.25%	**N/A**	N/A	N/A
Expected long-term rate of return —						
Health assets, net of tax	**N/A**	N/A	N/A	**6.85%**	6.85%	7.25%
Life assets and non-taxable health assets	**N/A**	N/A	N/A	**8.75%**	8.75%	9.25%

The following table represents the PBOP assumed health care cost trend rate for the next year and the assumed ultimate trend rate:

	Year Following December 31,	
	2004	2003
Health care cost trend rate assumed for next year	**7.00%**	8.00%
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2007**	2007

The annual per capita cost of covered health care benefits was assumed to decrease by one percentage point each year through 2007.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components	$ 1.0	$ (0.8)
Effect on postretirement benefit obligation	$15.1	$(13.3)

NU's investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans' assets within an acceptable level of risk. The investment strategy establishes target allocations, which are regularly reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU's historical 20-year compounded return of approximately 11 percent. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	2004 and 2003		**2004 and 2003**	
Asset Category	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity securities:				
United States	**45%**	9.25%	**55%**	9.25%
Non-United States	**14%**	9.25%	**11%**	9.25%
Emerging markets	**3%**	10.25%	**2%**	10.25%
Private	**8%**	14.25%	**—**	—
Debt Securities:				
Fixed income	**20%**	5.50%	**27%**	5.50%
High yield fixed income	**5%**	7.50%	**5%**	7.50%
Real estate	**5%**	7.50%	**—**	—

The actual asset allocations at December 31, 2004 and 2003, approximated these target asset allocations. The plans' actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
Asset Category	**2004**	2003	**2004**	2003
Equity securities:				
United States	**47%**	47%	**55%**	59%
Non-United States	**17%**	18%	**14%**	12%
Emerging markets	**3%**	3%	**1%**	1%
Private	**4%**	3%	**—**	—
Debt Securities:				
Fixed income	**19%**	19%	**28%**	25%
High yield fixed income	**5%**	5%	**2%**	3%
Real estate	**5%**	5%	**—**	—
Total	**100%**	100%	**100%**	100%

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid for the Pension and PBOP Plans:

(Millions of Dollars) Year	Pension Benefits	Postretirement Benefits	Government Subsidy
2005	$107.5	$ 39.5	$ —
2006	109.9	40.3	2.3
2007	112.9	40.8	2.3
2008	116.2	40.1	2.3
2009	120.0	39.4	2.2
2010–2014	685.5	186.4	10.4

Government subsidy represents amounts expected to be received from the federal government for the new Medicare prescription drug benefit under the PBOP Plan.

Contributions: NU does not expect to make any contributions to the Pension Plan in 2005 and expects to make $50.3 million in contributions to the PBOP Plan in 2005.

Currently, NU's policy is to annually fund an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code.

Postretirement health plan assets for non-union employees are subject to federal income taxes.

B. 401(k) Savings Plan

NU maintains a 401(k) Savings Plan for substantially all NU employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent cash and two percent NU shares. The 401(k) matching contributions of cash and NU shares made by NU were $10.5 million in 2004, $9.9 million in 2003 and $11.1 million in 2002.

C. Employee Stock Ownership Plan

NU maintains an Employee Stock Ownership Plan (ESOP) for purposes of allocating shares to employees participating in the NU's 401(k) Savings Plan. Under this arrangement, NU issued unsecured notes during 1991 and 1992 totaling $250 million, the proceeds of which were loaned to the ESOP trust (ESOP Notes) for the purchase of 10.8 million newly issued NU common shares (ESOP shares). The ESOP trust is obligated to make principal and interest payments to NU on the ESOP Notes at the same rate that ESOP shares are allocated to employees. NU makes annual contributions to the ESOP trust equal to the ESOP's debt service, less dividends received by the ESOP. NU's contribution to the ESOP trust totaled $12 million in 2004, $14.7 million in 2003 and $16.4 million in 2002. Interest expense on the unsecured notes was $5.7 million, $7.6 million and $9.5 million in 2004, 2003 and 2002, respectively. For the years ended December 31, 2004, 2003 and 2002, NU recognized $7.3 million, $6.9 million and $7.6 million, respectively, of expense related to the ESOP, excluding the interest expense on the unsecured notes.

All dividends received by the ESOP on unallocated shares are used to pay debt service and are not considered dividends for financial reporting purposes. During the first and second quarters of 2003, NU paid a $0.1375 per share quarterly dividend. During the third quarter of 2003 through the second quarter of 2004, NU paid a $0.15 per share quarterly dividend. NU paid a $0.1625 per share dividend during the third and fourth quarters of 2004.

In 2004 and 2003, the ESOP trust issued 567,907 and 607,020 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. At December 31, 2004 and 2003, total allocated ESOP shares were 8,183,711 and 7,615,804, respectively, and total unallocated ESOP shares were 2,616,474 and 3,184,381, respectively. The fair market value of the unallocated ESOP shares at December 31, 2004 and 2003, was $49.3 and $64.2 million, respectively.

D. Equity-Based Compensation

Impact of SFAS No. 123R: SFAS No. 123R will require NU to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees on or after July 1, 2005. NU is currently evaluating the impact of SFAS No. 123R on the Employee Share Purchase Plan (ESPP) and the Incentive Plan. Management believes that the impact of the adoption of SFAS No. 123R will not be material. See Note 1C, "New Accounting Standards," for more information on SFAS No. 123R.

Employee Share Purchase Plan: Since July 1998, NU has maintained an ESPP for all eligible employees. Under the ESPP, NU common shares are purchased at 6-month intervals at 85 percent of the lower of the price on the first or last day of each 6-month period. Employees may purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the purchase period. During 2004 and 2003, employees purchased 194,838 and 225,985 shares, respectively, at discounted prices of $14.17 and $15.90 in 2004 and $12.20 in 2003. At December 31, 2004 and 2003, 1,390,403 shares and 1,585,241 shares remained registered for future issuance under the ESPP, respectively.

Incentive Plans: Under the Incentive Plan, NU is authorized to grant various types of awards, including restricted stock, performance units, restricted stock units, and stock options to eligible employees and board members. The number of shares that may be utilized for grants and awards during a given calendar year may not exceed the aggregate of one percent of the total number of shares of NU common shares outstanding as of the first day of that calendar year and the shares not utilized in previous years. At December 31, 2004 and 2003, NU had 1,361,528 and 1,649,268 shares of common stock, respectively, registered for issuance under the Incentive Plan.

Restricted Stock and Restricted Stock Units: During 2004, NU granted 25,000 shares and 382,395 units of restricted stock and restricted stock units, respectively, under the Incentive Plan. The restricted shares granted in 2004 had a fair value of $0.4 million and were recorded as an offset to shareholders' equity. The restricted stock units granted in 2004 had a fair value of $7.4 million and were recorded as a liability in the accompanying consolidated balance sheets. During 2003, NU granted 383,589 shares of restricted stock under the Incentive Plan shares. Also during 2003, 75,000 restricted stock units were granted, all of which were forfeited January 1, 2004. During 2004, 2003 and 2002, $3.8 million, $2 million and $1 million, respectively, was expensed related to restricted stock and restricted stock units.

Performance Units: Under the Incentive Plan, NU also granted 30,122, 35,303 and 38,847 performance units during 2004, 2003 and 2002, respectively. The performance units vest ratably over three years and will be paid in cash at the end of the vesting period. NU records a liability for the performance units based on the achievement of the performance unit goals. A liability of $3.2 million and $1.5 million was recorded at December 31, 2004 and 2003, respectively, for these performance units. During 2004, 2003 and 2002, $1.7 million, $0.2 million and $1.3 million, respectively, was recorded as an expense related to these performance units.

Stock Options: Prior to 2003, NU granted stock options to certain employees. The exercise price of stock options, as set at the time of grant, was equal to the fair market value per share at the date of grant, and therefore no equity-based compensation cost was reflected in net income. No stock options were granted during 2004 or 2003. A summary of stock option transactions is as follows:

		Exercise Price Per Share	
	Options	Range	Weighted Average
Outstanding — December 31, 2001	3,009,916	$ 9.6250 — $22.2500	$16.4467
Granted	1,337,345	$16.5500 — $19.8700	$17.8284
Exercised	(262,800)	$10.0134 — $19.5000	$15.4666
Forfeited and cancelled	(247,152)	$14.9375 — $22.2500	$18.3473
Outstanding — December 31, 2002	3,837,309	$ 9.6250 — $22.2500	$16.8738
Exercised	(562,982)	$ 9.6250 — $19.5000	$14.6223
Forfeited and cancelled	(151,005)	$14.9375 — $21.0300	$19.0227
Outstanding — December 31, 2003	3,123,322	$ 9.6250 — $22.2500	$17.1270
Exercised	(612,666)	$ 9.6250 — $19.5000	$12.3181
Forfeited and cancelled	(516,914)	$16.5500 — $19.5000	$16.6139
Outstanding — December 31, 2004	**1,993,742**	**$14.9375 — $22.2500**	**$18.7370**
Exercisable — December 31, 2002	1,956,555	$ 9.6250 — $22.2500	$15.3758
Exercisable — December 31, 2003	2,027,413	$ 9.6250 — $22.2500	$16.6969
Exercisable — December 31, 2004	**1,877,595**	**$14.9375 — $22.2500**	**$18.7778**

For certain options that were granted in 2002, the vesting schedule for these options is ratably over three years from the date of grant. Additionally, certain options granted in 2002 vest 50 percent at the date of grant and 50 percent one year from the date of grant, while other options granted in 2002 vest 100 percent after five years.

The fair value of each stock option grant has been estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions. No stock options were granted during 2004 or 2003.

	2002
Risk-free interest rate	4.86%
Expected life	10 years
Expected volatility	23.71%
Expected dividend yield	2.11%

The weighted average grant date fair values of options granted during 2002 was $5.64. The weighted average remaining contractual lives for the options outstanding at December 31, 2004 is 6.03 years.

In January 2005, 490,600 options that were outstanding and exercisable at December 31, 2004 with exercise prices ranging from $18.4375 to $21.03 were forfeited. This forfeiture resulted in outstanding and exercisable options in January 2005 of 1,503,142 and 1,386,995, respectively.

For additional information regarding equity-based compensation, see Note 1N, "Summary of Significant Accounting Policies — Equity-Based Compensation."

E. Supplemental Executive Retirement and Other Plans

NU has maintained a SERP since 1987. The SERP provides its participants, who are executives of NU, with benefits that would have been provided to them under NU's retirement plan if certain Internal Revenue Code and other limitations were not imposed. The SERP liability of $24.2 million and $22.1 million at December 31, 2004 and 2003, respectively, represents NU's actuarially-determined obligation under the SERP. During 2004, 2003 and 2002, $4 million, $3.9 million, and $3.8 million, respectively, was expensed related to the SERP.

The SERP is the only NU retirement plan for which a minimum pension liability has been recorded. Recording this minimum pension liability resulted in a reduction of $0.1 million to accumulated other comprehensive income.

NU maintains a plan for retirement and other benefits for certain current and past company officers. The actuarially-determined liability for this plan was $36.7 million and $35.5 million at December 31, 2004 and 2003, respectively. During 2004, 2003 and 2002, $4.5 million, $6.3 million and $7.8 million, respectively, was expensed related to this plan.

For further information regarding SERP investments, see Note 8, "Marketable Securities," to the consolidated financial statements.

5. Goodwill and Other Intangible Assets

SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount. Excluding adjustments to the purchase price allocation related to the acquisition of Woods Electrical Co., Inc. (Woods Electrical) and Woods Network recorded in 2003, there were no impairments or adjustments to the goodwill balances during 2004 or 2003. The Woods Electrical and Woods Network adjustments primarily related to the reclassification between goodwill and intangible assets.

NU's reporting units that maintain goodwill are generally consistent with the operating segments underlying the reportable segments identified in Note 15, "Segment Information," to the consolidated financial statements. Consistent with the way management reviews the operating results of its reporting units, NU's reporting units under the NU Enterprises reportable segment include: 1) the merchant energy reporting unit and 2) the energy services reporting unit. The merchant energy reporting unit is comprised of the operations of Select Energy, NGC and the generation operations of HWP, while the energy services reporting unit

is comprised of the operations of SESI, NGS and Woods Network. As a result, NU's reporting units that maintain goodwill are as follows: the Yankee Gas reporting unit, which is classified under the Utility Group — gas reportable segment; the merchant energy reporting unit, which is classified under the NU Enterprises — merchant energy reportable segment; and the energy services reporting unit, which is classified under NU Enterprises — services and other.

NU has completed its impairment analyses as of October 1, 2004, for all reporting units that maintain goodwill and has determined that no impairment exists. In completing these analyses, the fair values of the reporting units were estimated using both discounted cash flow methodologies and an analysis of comparable companies or transactions.

At December 31, 2004, NU maintained $319.9 million of goodwill that is no longer being amortized, $10.8 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. At December 31, 2003, NU maintained $319.9 million of goodwill that is no longer being amortized, $14.4 million of identifiable intangible assets subject to amortization and $8.5 million of intangible assets not subject to amortization. A summary of NU's goodwill balances at December 31, 2004 and December 31, 2003, by reportable segment and reporting unit is as follows:

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

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

At December 31, 2004 and December 31, 2003, NU's intangible assets and accumulated amortization, all of which relates to NU Enterprises, consisted of the following:

(Millions of Dollars)	At December 31, 2004 Gross Balance	Accumulated Amortization	Net Balance
Intangible assets subject to amortization:			
Exclusivity agreement	**$17.7**	**$ 9.8**	**$ 7.9**
Customer list	**6.6**	**3.7**	**2.9**
Totals	**$24.3**	**$13.5**	**$10.8**
Intangible assets not subject to amortization:			
Customer relationships	**$ 5.2**		
Tradenames	**3.3**		
Totals	**$ 8.5**		

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

NU recorded amortization expense of $3.6 million and $3.7 million for the years ended December 31, 2004 and 2003, respectively, related to these intangible assets. Substantially all of the intangible assets subject to amortization are being amortized over a period of 8.5 years.

Based on the current amount of intangible assets subject to amortization, the estimated annual amortization expense for each of the succeeding 5 years from 2005 through 2009 is $3.6 million in 2005 through 2007 and no amortization expense in 2008 or 2009. These amounts may vary as acquisitions and dispositions occur in the future.

6. Commitments and Contingencies

A. Regulatory Developments and Rate Matters

Connecticut:

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

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

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany tax liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P's request, and on October 24, 2003, CL&P appealed the DPUC's final decision to the Connecticut Superior Court. The appeal has been fully briefed and argued. A decision from the court is not expected to be issued until the second quarter of 2005. If CL&P's request is granted through these court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

New Hampshire:

SCRC Reconciliation Filings: The SCRC allows PSNH to recover its stranded costs. On an annual basis, PSNH files with the NHPUC a SCRC reconciliation filing for the preceding calendar year. This filing includes the reconciliation of stranded cost revenues billed with stranded costs, and transition energy service and default energy service (TS/DS) revenues billed with TS/DS costs. The NHPUC reviews the filing, including a prudence review of PSNH's generation operations. The cumulative deferral of SCRC revenues in excess of costs was $208.6 million at December 31, 2004. This cumulative deferral will decrease the amount of non-securitized stranded costs that will have to be recovered from PSNH's customers in the future from $411.3 million to $202.7 million.

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

The 2004 SCRC reconciliation filing is expected to be filed with the NHPUC by May 2, 2005. Management does not expect the NHPUC's review of the 2004 SCRC filing to have a material impact on PSNH's net income or financial position.

The SCRC and TS/DS rate mechanisms currently reconcile accrued expenses with billed revenues on a monthly basis. On May 2, 2005, PSNH expects to file its annual 2004 SCRC and TS/DS reconciliation that will include a request to include unbilled revenues as part of the reconciliation process. This request will allow for the reconciliation of revenues on an accrual basis with the current accrued expenses recovered through the SCRC and TS/DS rate mechanisms, consistent with accrual accounting. At December 31, 2004, the PSNH unbilled revenue balance related to SCRC and TS/DS was $11.7 million and $16.7 million, respectively. If approved, this change will allow for the inclusion of accrued unbilled revenue balances in the recovery of SCRC and TS/DS costs. Management believes that the unbilled revenue balance related to SCRC and TS/DS is probable of being recovered from PSNH's customers.

Massachusetts:

Transition Cost Reconciliation: On March 31, 2004, WMECO filed its 2003 transition cost reconciliation with the Massachusetts Department of Telecommunications and Energy (DTE). This filing reconciled the recovery of generation-related stranded costs for calendar year 2003. The DTE has not initiated its investigation into this filing. WMECO expects to file its 2004 transition cost reconciliation with the DTE on March 31, 2005. The DTE has combined the 2003 transition cost reconciliation filing and the 2004 transition cost reconciliation filing into a single proceeding. The timing of this decision in the combined proceeding is uncertain, but management does not expect the outcome to have a material adverse impact on WMECO's net income or financial position.

B. Environmental Matters

General: NU is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. As such, NU has an active environmental auditing and training program and believes that it is substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued using a probabilistic model approach when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. The probabilistic model approach estimates the liability based on the most likely action plan from a variety of available remediation options, including, no action is required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring.

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors including new information concerning either the level of contamination at the site, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities on the consolidated balance sheets represent management's best estimate of the liability for environmental costs and takes into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs at December 31, 2004 and 2003, NU had $38.7 million and $40.8 million, respectively, recorded as environmental reserves. A reconciliation of the total reserve amount at December 31, 2004 and 2003 is as follows:

	For the Years Ended December 31,	
(Millions of Dollars)	**2004**	2003
Balance at beginning of year	**$40.8**	$41.9
Additions and adjustments	**6.4**	4.1
Payments	**(8.5)**	(5.2)
Balance at end of year	**$38.7**	$40.8

NU currently has 53 sites included in the environmental reserve. Of those 53 sites, 25 sites are in the remediation or long-term monitoring phase, 22 sites have had site assessments completed and the remaining six sites are in the preliminary stages of site assessment.

For nine sites that are included in the company's liability for environmental costs, the information known and nature of the remediation options at those sites allow an estimate of the range of losses to be made. These sites primarily relate to manufactured gas plant (MGP) sites. At December 31, 2004, $8.1 million has been accrued as a liability for

these sites, which represents management's best estimate of the liability for environmental costs. This amount differs from an estimated range of loss from $4.9 million to $25.8 million as management utilizes the probabilistic model approach to make its estimate of the liability for environmental costs. For the 45 remaining sites for which an estimate is based on the probabilistic model approach, determining a range of estimated losses is not possible.

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2004, there are ten sites for which there are unasserted claims; however, any related remediation costs are not probable or estimable at this time. NU's environmental liability also takes into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate previously contaminated sites and any other infrequent and non-recurring clean up costs.

MGP Sites: MGP sites comprise the largest portion of NU's environmental liability. MGPs are sites that manufactured gas from coal produced certain byproducts that may pose risk to human health and the environment. At December 31, 2004 and 2003, $33.2 million and $36.3 million, respectively, represent amounts for the site assessment and remediation of MGPs. At December 31, 2004 and 2003, the five largest MGP sites comprise approximately 58 percent and 57 percent, respectively, of the total MGP environmental liability.

At December 31, 2004, NU has one site that is held for sale. The site, a former MGP site, is currently held for sale under a pending purchase and sale agreement. NU is currently remediating the property and has been deferring the costs associated with those remediation efforts as allowed by a regulatory order. At December 31, 2004, NU had $7.9 million related to remediation efforts at the property and other sale costs recorded in other deferred debits on the accompanying consolidated balance sheets. A final decision was reached by the DPUC on January 19, 2005, which approved the sale proceedings of the former MGP site. The final decision approved the price of $24 million for the sale of the land and also approved the deferral of the gain in the amount of $13.8 million ($8.3 million after-tax). The purchase and sale agreement releases NU from all environmental claims arising out of or in connection with the property.

CERCLA Matters: The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and its amendments or state equivalents impose joint and several strict liabilities, regardless of fault, upon generators of hazardous substances resulting in removal and remediation costs and environmental damages. Liabilities under these laws can be material and in some instances may be imposed without regard to fault or for past acts that may have been lawful at the time they occurred. NU has five superfund sites under CERCLA for which it has been notified that it is a potentially responsible party (PRP). For sites where there are other PRPs and NU's subsidiaries are not managing the site assessment and remediation, the liability accrued represents NU's estimate of what it will need to pay to settle its obligations with respect to the site.

It is possible that new information or future developments could require a reassessment of the potential exposure to related environmental matters. As this information becomes available management will continue to assess the potential exposure and adjust the reserves accordingly, as necessary.

Rate Recovery: PSNH and Yankee Gas have rate recovery mechanisms for environmental costs. CL&P recovers a certain level of environmental costs currently in rates but does not have an environmental cost recovery tracking mechanism. Accordingly, changes in CL&P's environmental reserves impact CL&P's earnings. WMECO does not have a regulatory mechanism to recover environmental costs from its customers, and changes in WMECO's environmental reserves impact WMECO's earnings.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982 (the Act), CL&P, PSNH, WMECO, and NAEC must pay the DOE for the disposal of spent nuclear fuel and high-level radioactive waste. The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made prior to the first delivery of spent fuel to the DOE. Until such payment is made, the outstanding balance will continue to accrue interest at the 3-month treasury bill yield rate. At December 31, 2004 and 2003, fees due to the DOE for the disposal of Prior Period Fuel were $259.7 million and $256.4 million, respectively, including interest costs of $177.6 million and $174.3 million, respectively.

During 2004, WMECO established a trust, which holds marketable securities, to fund amounts due to the DOE for the disposal of WMECO's prior period fuel. For further information on this trust see Note 8, "Marketable Securities," to the consolidated financial statements.

D. Long-Term Contractual Arrangements

VYNPC: Previously under the terms of their agreements, NU's companies paid their ownership (or entitlement) shares of costs, which included depreciation, O&M expenses, taxes, the estimated cost of decommissioning, and a return on invested capital to VYNPC and recorded these costs as purchased-power expenses. On July 31, 2002, VYNPC consummated the sale of its nuclear generating unit to a subsidiary of Entergy Corporation (Entergy) for approximately $180 million. Under the terms of the sale, CL&P, PSNH and WMECO will continue to buy approximately 16 percent of the plant's output through March 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $26.8 million in 2004, $29.9 million in 2003 and $27.6 million in 2002.

Electricity Procurement Contracts: CL&P, PSNH and WMECO have entered into various arrangements for the purchase of electricity. The total cost of purchases under these arrangements amounted to $323.3 million in 2004, $283.4 million in 2003 and $278.3 million in 2002. These amounts relate to IPP contracts and do not include contractual commitments related to CL&P's standard offer, PSNH's short-term power supply management or WMECO's standard offer and default service.

Natural Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of a specified quantity of natural gas in the normal course of business as part of its portfolio to meet its actual

sales commitments. These contracts have expiration dates in 2006 and 2007. The total cost of Yankee Gas' procurement portfolio, including these contracts, amounted to $250.5 million in 2004, $218.6 million in 2003 and $158 million in 2002.

Hydro-Quebec: Along with other New England utilities, CL&P, PSNH, WMECO, and HWP have entered into agreements to support transmission and terminal facilities to import electricity from the Hydro-Quebec system in Canada. CL&P, PSNH, WMECO, and HWP are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual O&M expenses and capital costs of those facilities. The total cost of these agreements amounted to $23.7 million in 2004, $25.3 million in 2003 and $26 million in 2002.

Yankee Gas Liquefied Natural Gas (LNG) Storage Facility: In 2004, Yankee Gas signed a contract for the design and building of the LNG facility. Yankee Gas anticipates that the facility will become operational in late 2007 in time for the 2007/2008 heating season. Certain future estimated construction expenditures totaling $21.4 million are not included in the contract signed to build the LNG facility and are not included in the following table of estimated future annual Utility Group costs. The remaining $21.4 million does not include $12.9 million that was spent through 2004.

Northern Wood Power Project: In October 2004, PSNH received the approvals necessary to begin construction related to the conversion of one of three 50 megawatt units at the coal-fired Schiller Station to burn wood. Construction of the $75 million Northern Wood Power Project has begun and is expected to be completed by late 2006. Certain other estimated construction expenditures totaling $8.6 million are not included in the contract signed to perform the Schiller Station conversion and are not included in the table of estimated future annual Utility Group costs below.

Yankee Companies FERC-Approved Billings: NU has significant decommissioning and plant closure cost obligations to the Yankee Companies. Each plant has been shut down and is undergoing decommissioning. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including NU's electric utility companies CL&P, PSNH and WMECO. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates. YAEC and MYAPC received FERC approval to collect all presently estimated decommissioning costs. The table of estimated future annual Utility Group costs below includes the decommissioning and closure costs for YAEC, MYAPC and CYAPC.

Estimated Future Annual Utility Group Costs: The estimated future annual costs of NU's significant long-term contractual arrangements are as follows:

(Millions of Dollars)	2005	2006	2007	2008	2009	Thereafter
VYNPC	$ 27.1	$ 28.5	$ 27.5	$ 27.9	$ 30.9	$ 66.5
Electricity procurement contracts	319.0	322.0	253.0	218.3	190.0	1,103.1
Natural gas procurement contracts	201.8	180.5	82.7	38.5	38.3	103.2
Hydro-Quebec	24.8	24.4	22.8	20.4	19.6	215.6
Yankee Gas LNG facility	27.9	41.8	4.0	—	—	—
Northern Wood Power Project	39.3	7.5	—	—	—	—
Yankee Companies FERC-approved billings	89.6	78.2	71.0	60.9	57.2	56.2
Totals	$729.5	$682.9	$461.0	$366.0	$336.0	$1,544.6

NU Enterprises Purchase Agreements: Select Energy maintains long-term agreements to purchase energy in the normal course of business as part of its portfolio of resources to meet its actual or expected sales commitments. The aggregate amount of these purchase contracts was $6.2 billion at December 31, 2004 as follows:

(Millions of Dollars)	
Year	
2005	$4,940.1
2006	650.8
2007	156.4
2008	99.0
2009	85.6
Thereafter	261.1
Total	$6,193.0

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

The amounts and timing of Select Energy's purchase agreements could be impacted by the NU Enterprises' strategic review.

E. Deferred Contractual Obligations

CYAPC's estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. The revised estimate reflects the increases in the projected costs of spent fuel storage, increased security and liability and property insurance costs, and the fact that CYAPC is now self-performing all work to complete the decommissioning of the plant due to the termination of the decommissioning contract with Bechtel in July 2003. NU's share of CYAPC's increase in decommissioning and plant closure costs is approximately $194 million. On July 1, 2004, CYAPC filed with the FERC for recovery of these increased costs. In the filing, CYAPC sought to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection beginning on February 1, 2005, subject to refund, and scheduled hearings for May 2005. In total, NU's estimated remaining decommissioning and plant closure obligation for CYAPC is $308.7 million at December 31, 2004.

On June 10, 2004, the DPUC and Office of Consumer Counsel (OCC) filed a petition seeking a declaratory order that CYAPC be allowed to recover all decommissioning costs from its wholesale purchasers, including CL&P, PSNH and WMECO, but that such purchasers may not be allowed to recover in their retail rates any costs that the FERC might determine to have been imprudently incurred. On August 30, 2004, the FERC denied this petition. On September 29, 2004, the DPUC and OCC asked the FERC to reconsider the petition. On October 29, 2004, the FERC issued an order granting further consideration regarding the DPUC's and OCC's petition for reconsideration. No hearing date has been established for this reconsideration.

On February 22, 2005, the DPUC filed testimony with the FERC. In its filed testimony, the DPUC argues that approximately $215 million to $225 million of CYAPC's requested increase is due to CYAPC's imprudence in managing the decommissioning project while Bechtel was the contractor. Therefore, the DPUC recommends a total disallowance of between $225 million to $234 million. Hearings are scheduled to begin on June 1, 2005. NU's share of the DPUC's recommended disallowance is between $110 million to $115 million.

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

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

In the prejudgment remedy proceeding before the Connecticut Supreme Court (the Court), Bechtel sought garnishment of the CYAPC decommissioning trust and related payments. In October 2004, Bechtel and CYAPC entered into an agreement under which Bechtel waived its right to seek garnishment of the decommissioning trust and related payments in return for the potential attachment of CYAPC's real property in Connecticut and the escrowing of $41.7 million the sponsors are scheduled to pay to CYAPC through June 30, 2007 in respect to CYAPC's common equity. This stipulation is subject to approval of the Court and would not be implemented until the Court found that such assets were subject to attachment. CYAPC has contested the attachability of such assets. The DPUC is an intervener in this proceeding.

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

The Yankee Companies also filed litigation in 1998 charging that the federal government breached contracts it entered into with each company in 1983 under the Act. Under the Act, the DOE was to begin removing spent nuclear fuel from the nuclear plants of YAEC, MYAPC and CYAPC no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and spent nuclear fuel is stored on the sites of the Yankee Companies' plants. YAEC, MYAPC and CYAPC collected the funds for payments into the nuclear waste fund from wholesale utility customers under FERC-approved contract rates. The wholesale utility customers in turn collect these payments from their retail electric customers. The Yankee Companies' individual damage claims attributed to the government's breach totaling $548 million are specific to each plant and include incremental storage, security, construction and other costs through 2010, which is the earliest date the DOE projects that it will begin removing nuclear fuel. The YAEC damage claim is $191 million, the MYAPC claim is $160 million and the CYAPC claim is $197 million.

The DOE trial ended on August 31, 2004 and a verdict has not been reached. The current Yankee Companies' rates do not include an amount for recovery of damages in this matter. Management can predict neither the outcome of this matter nor its ultimate impact on NU.

F. NRG Energy, Inc. Exposures

Certain subsidiaries of NU, including CL&P and Yankee Gas, have entered into transactions with NRG Energy, Inc. (NRG) and certain of its subsidiaries. On May 14, 2003, NRG and certain of its subsidiaries filed voluntary bankruptcy petitions. On December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions relate to 1) the recovery of congestion charges incurred by NRG prior to the implementation of SMD on March 1, 2003, 2) the recovery of CL&P's station service billings from NRG, and 3) the recovery of Yankee Gas' and CL&P's expenditures that were incurred related to an NRG subsidiary's generating plant construction project that is now abandoned. While it is unable to determine the ultimate outcome of these issues, management does not expect their resolution will have a material adverse effect on NU's consolidated financial condition or results of operations.

G. Impacts of Decision to Exit NU Enterprises' Wholesale Marketing Contracts and to Explore Ways to Divest the NU Enterprises' Services Businesses

The March 2005 decision to exit NU Enterprises' wholesale marketing business and to explore ways to divest NU Enterprises' services businesses creates certain potential loss contingencies. They could be material and could include:

- The impairment of long-lived assets if they are no longer held and used and become held for sale at expected sales prices that are less than carrying values.
- The impairment of goodwill if expected cash flows that support the fair values of the reporting units that hold goodwill are reduced significantly by a change in business strategy or a decision to sell all or portions of the reporting units at prices less than carrying values.
- The impairment of intangible assets if expected cash flows that support them are reduced to below their carrying values.

- The recognition of closure costs such as severance, benefit plan curtailments, and lease termination payments.
- The recognition of losses associated with settling energy contracts currently accounted for on an accrual method of accounting that have negative fair values at the time of settlement.
- The termination of the normal purchase and sales exception to fair value accounting for derivatives and the resulting recognition of losses or gains on changes in fair value of the contracts since inception.

NU expects to record a charge in the first quarter of 2005 associated with the wholesale marketing and energy services businesses. The level of that charge will depend on a number of factors, including how the disposition of those businesses is accomplished.

H. Consolidated Edison, Inc. Merger Litigation

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

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

On May 11, 2001, Con Edison filed an amended complaint seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation in an unspecified amount, but which Con Edison's Chief Financial Officer has testified is at least $314 million. NU disputes both Con Edison's entitlement to any damages as well as its method of computing its alleged damages.

The companies completed discovery in the litigation and submitted cross motions for summary judgment. The court denied Con Edison's motion in its entirety, leaving intact NU's claim for breach of the Merger Agreement, and partially granted NU's motion for summary judgment by eliminating Con Edison's claims against NU for fraud and negligent misrepresentation.

An intervener in this litigation has made the claim that NU shareholders at March 5, 2001 are entitled to damages from Con Edison, if any, and not current NU shareholders.

Appeals on this and other issues are now pending and no trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU.

7. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Cash and Cash Equivalents, Restricted Cash — LMP, and Special Deposits: The carrying amounts approximate fair value due to the short-term nature of these cash items.

SERP Investments: Investments held for the benefit of the SERP are recorded at fair market value based upon quoted market prices. The investments having a cost basis of $50.1 million and $33.8 million held for benefit of the SERP were recorded at their fair market values at December 31, 2004 and 2003, of $55.1 million and $36.9 million, respectively. For further information regarding the SERP liabilities and related investments, see Note 4E, "Employee Benefits — Supplemental Executive Retirement and Other Plans," and Note 8, "Marketable Securities," to the consolidated financial statements.

Prior Spent Nuclear Fuel Trust: During 2004, WMECO established a trust to fund the amounts due to the DOE for its prior spent nuclear fuel obligation. These investments having a cost basis of $49.5 million were recorded at their fair market value at December 31, 2004 of $49.3 million. For further information regarding these investments, see Note 8, "Marketable Securities," to the consolidated financial statements.

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of NU's fixed-rate securities is based upon the quoted market price for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of NU's financial instruments and the estimated fair values are as follows:

	At December 31, 2004	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 101.4
Long-term debt —		
First mortgage bonds	1,072.3	1,228.8
Other long-term debt	1,812.4	1,898.7
Rate reduction bonds	1,546.5	1,674.0

	At December 31, 2003	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 87.5
Long-term debt —		
First mortgage bonds	743.0	833.3
Other long-term debt	1,810.7	1,896.5
Rate reduction bonds	1,730.0	1,860.7

Other long-term debt includes $259.7 million and $256.4 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2004 and 2003, respectively.

Other Financial Instruments: The carrying value of financial instruments included in current assets and current liabilities, including investments in securitizable assets, approximates their fair value.

8. Marketable Securities

The following is a summary of NU's available-for-sale securities related to NU's SERP securities which are included in deferred debits and other assets - other on the accompanying consolidated balance sheets, and WMECO's prior spent nuclear fuel trust:

(Millions of Dollars)	At December 31, 2004	2003
SERP securities	$ 55.1	$36.9
WMECO prior spent nuclear fuel trust	49.3	—
Totals	$104.4	$36.9

	Amortized Cost	At December 31, 2004 Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$19.3	$3.8	$(0.2)	$ 22.9
Non-United States equity securities	5.6	1.3	—	6.9
Fixed income securities	74.7	0.3	(0.4)	74.6
Totals	$99.6	$5.4	$(0.6)	$104.4

	Amortized Cost	At December 31, 2003 Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$13.2	$2.5	$(0.1)	$15.6
Non-United States equity securities	3.4	0.7	—	4.1
Fixed income securities	17.2	0.1	(0.1)	17.2
Total SERP securities	$33.8	$3.3	$(0.2)	$36.9

At December 31, 2004 and 2003 NU has evaluated the securities in an unrealized loss position and has determined that none of the related unrealized losses are deemed to be other-than-temporary in nature.

For information related to the change in net unrealized holding gains and losses included in shareholders' equity, see Note 12, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

For years ended December 31, 2004, 2003, and 2002, realized gains and losses recognized on the sale of available-for-sale securities are as follows (in millions):

	Realized Gains	Realized Losses	Net Realized Gains/(Losses)
2004	**$0.9**	**$(0.3)**	**$0.6**
2003	0.5	(0.1)	0.4
2002	0.8	(1.4)	(0.6)

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

Proceeds from the sale of these securities totaled $56.7 million, $34.1 million, and $7.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

At December 31, 2004, the contractual maturities of the available-for-sale securities are as follows (in millions):

	Amortized Cost	Estimated Fair Value
Less than one year	$47.6	$ 52.5
One to five years	21.9	21.7
Six to ten years	6.0	6.0
Greater than ten years	24.1	24.2
Total	$99.6	$104.4

For further information regarding marketable securities, see Note 1X, "Summary of Significant Accounting Policies — Marketable Securities" to the consolidated financial statements.

9. Leases

NU has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. The provisions of these lease agreements generally provide for renewal options. Certain lease agreements contain contingent lease payments. The contingent lease payments are based on various factors, such as, the commercial paper rate plus a credit spread or the consumer price index.

Capital lease rental payments charged to operating expense were $3.3 million in 2004, $3.7 million in 2003 and $1.7 million in 2002. Interest included in capital lease rental payments was $2 million in 2004, $2.3 million in 2003 and $0.6 million in 2002. Operating lease rental payments charged to expense were $16.3 million in 2004, $16.1 million in 2003 and $14.5 million in 2002.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, at December 31, 2004 are as follows:

(Millions of Dollars)	Capital Leases	Operating Leases
2005	$ 3.1	$ 30.9
2006	2.9	28.5
2007	2.6	24.5
2008	2.3	21.0
2009	2.0	12.5
Thereafter	18.1	41.3
Future minimum lease payments	31.0	$158.7
Less amount representing interest	16.2	
Present value of future minimum lease payments	$14.8	

10. Long-Term Debt

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2004, for the years 2005 through 2009 and thereafter, are as follows:

(Millions of Dollars)	
Year	
2005	$ 90.8
2006	27.0
2007	8.2
2008	159.8
2009	61.5
Thereafter	2,277.7
Total	$2,625.0

Essentially all utility plant of CL&P, PSNH, NGC, and Yankee Energy System, Inc. is subject to the liens of each company's respective first mortgage bond indenture.

CL&P has $315.3 million of pollution control notes secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indentures.

CL&P has $62 million of tax-exempt Pollution Control Revenue Bonds (PCRBs) with bond insurance and secured by the first mortgage bonds. For financial reporting purposes, this debt is not considered to be first mortgage bonds unless CL&P failed to meet its obligations under the PCRBs.

PSNH entered into financing arrangements with the Business Finance Authority (BFA) of the state of New Hampshire, pursuant to which, the BFA issued five series of PCRBs and loaned the proceeds to PSNH. At December 31, 2004 and 2003, $407.3 million of the PCRBs were outstanding. PSNH's obligation to repay each series of PCRBs is secured by bond insurance and the first mortgage bonds. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. For financial reporting purposes, these first mortgage bonds would not be considered outstanding unless PSNH failed to meet its obligations under the PCRBs.

NU's long-term debt agreements provide that certain of its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including but not limited to, debt service coverage ratios and interest coverage ratios. The parties to these agreements currently are and expect to remain in compliance with these covenants.

Long-term debt — first mortgage bonds at December 31, 2004 includes the issuance of $280 million, $125 million and $50 million of long-term debt related to CL&P, Yankee Gas and PSNH during 2004, respectively.

The weighted-average effective interest rate on the variable-rate pollution control notes ranged from 1.24 percent to 1.26 percent for 2004 and 0.99 percent to 1.08 percent for 2003.

The interest rate of 3.35 percent is effective through October 1, 2008 at which time the bonds will be remarketed, and the interest rate will be adjusted.

Other long-term debt — other at December 31, 2004, includes the issuance of $7.5 million and $50 million of long-term debt related to SESI and WMECO during 2004. In 2004, SESI sold $30 million of receivables related to the energy savings contract projects. The transfer of receivables to the unaffiliated third party qualified as a sale under SFAS No. 140. Accordingly, the $30 million sold at December 31, 2004 is not included as debt in the consolidated financial statements.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 1X, "Marketable Securities," and Note 6C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

The fair value of the NU parent 7.25 percent amortizing note, due 2012 in the amount of $263 million is hedged with a fixed to floating interest rate swap. The change in fair value of the debt was recorded as an adjustment to long-term debt with an equal and offsetting adjustment to derivative assets for the change in fair value of the fixed to floating interest rate swap.

11. Dividend Restrictions

The Federal Power Act, the Public Utility Holding Act of 1935 (the Act), and certain state statutes limit the payment of dividends by CL&P, PSNH, and WMECO to their respective retained earnings balances. Yankee Gas is also subject to the restrictions under the 1935 Act.

Certain consolidated subsidiaries also have dividend restrictions imposed by their long-term debt agreements. These restrictions limit the amount of retained earnings available for NU common dividends. At December 31, 2004, retained earnings available for payment of dividends totaled $343.5 million.

NGC is subject to certain dividend payment restrictions under its bond covenants.

The Utility Group credit agreement also limits dividend payments subject to the requirements that each subsidiaries' total debt to total capitalization ratio does not exceed 65 percent.

12. Accumulated Other Comprehensive Income/(Loss)

The accumulated balance for each other comprehensive income/(loss) item is as follows:

(Millions of Dollars)	December 31, 2003	Current Period Change	December 31, 2004
Qualified cash flow hedging instruments	$24.8	$(28.3)	**$(3.5)**
Unrealized gains on securities	2.0	1.2	**3.2**
Minimum supplemental executive retirement pension liability adjustments	(0.8)	(0.1)	**(0.9)**
Accumulated other comprehensive income	$26.0	$(27.2)	**(1.2)**

(Millions of Dollars)	December 31, 2002	Current Period Change	December 31, 2003
Qualified cash flow hedging instruments	$15.5	$ 9.3	$24.8
Unrealized (losses)/gains on securities	(0.1)	2.1	2.0
Minimum supplemental executive retirement pension liability adjustments	(0.5)	(0.3)	(0.8)
Accumulated other comprehensive income	$14.9	$11.1	$26.0

The changes in the components of other comprehensive income/(loss) are reported net of the following income tax effects:

(Millions of Dollars)	**2004**	2003	2002
Qualified cash flow hedging instruments	**$14.4**	$(6.4)	$(33.1)
Unrealized (losses)/gains on securities	**(0.7)**	(1.4)	3.3
Minimum supplemental executive retirement pension liability adjustments	**—**	—	—
Accumulated other comprehensive income	**$13.7**	$(7.8)	$(29.8)

Accumulated other comprehensive income/(loss) fair value adjustments of NU's qualified cash flow hedging instruments are as follows:

(Millions of Dollars, Net of Tax)	At December 31, 2004	2003
Balance at beginning of year	**$24.8**	$15.5
Hedged transactions recognized into earnings	**(57.8)**	(5.3)
Change in fair value	**25.0**	5.0
Cash flow transactions entered into for the period	**4.5**	9.6
Net change associated with the current period hedging transactions	**(28.3)**	9.3
Total fair value adjustments included in accumulated other comprehensive income	**$ (3.5)**	$24.8

13. Earnings Per Share

EPS is computed based upon the weighted-average number of common shares outstanding, excluding unallocated ESOP shares, during each year. Diluted EPS is computed on the basis of the weighted-average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. In 2004, 2003 and 2002, 696,994 options, 355,153 options and 2,968,933 options, respectively, were excluded from the following table as these options were antidilutive. The following table sets forth the components of basic and diluted EPS.

(Millions of Dollars, except share information)	2004	2003	2002
Income before cumulative effect of accounting change	**$116.6**	$121.1	$152.1
Cumulative effect of accounting change, net of tax benefit	**—**	(4.7)	—
Net income	**$116.6**	$116.4	$152.1
Basic EPS common shares outstanding (average)	**128,245,860**	127,114,743	129,150,549
Dilutive effect of employee stock options	**150,216**	125,981	190,811
Fully diluted EPS common shares outstanding (average)	**128,396,076**	127,240,724	129,341,360
Basic and fully diluted EPS:			
Income before cumulative effect of accounting change	**$ 0.91**	$ 0.95	$ 1.18
Cumulative effect of accounting change, net of tax benefit	**—**	(0.04)	—
Net income	**$ 0.91**	$ 0.91	$ 1.18

14. Nuclear Generation Asset Divestitures

Seabrook: On November 1, 2002, CL&P and NAEC consummated the sale of their 40.04 percent combined ownership interest in Seabrook to a subsidiary of FPL. CL&P, NAEC and certain other of the joint owners collectively sold 88.2 percent of Seabrook to FPL. NU received approximately $367 million of total cash proceeds from the sale of Seabrook and another approximately $17 million from Baycorp Holdings, Ltd. (Baycorp), as a result of the sale of its interest in Seabrook. A portion of this cash was used to repay all $90 million of NAEC's outstanding debt and other short-term debt, to return a portion of NAEC's equity to NU and was used to pay approximately $93 million in taxes. The remaining proceeds received by NAEC were refunded to PSNH through the Seabrook Power Contracts. As part of the sale, FPL assumed responsibility for decommissioning Seabrook. NAEC and CL&P recorded a gain on the sale in the amount of approximately $187 million, which was primarily used to offset stranded costs.

In the third quarter of 2002, CL&P and NAEC received regulatory approvals for the sale of Seabrook from the DPUC and the NHPUC. As a result of these approvals, CL&P and NAEC eliminated $0.6 million and $13.9 million, respectively, on an after-tax basis, of reserves related to their respective ownership shares of certain Seabrook assets.

On October 10, 2000, NU reached an agreement with Baycorp, a 15 percent joint owner of Seabrook, under which NU guaranteed a minimum sale price and NU and Baycorp would share the excess proceeds if the sale of Seabrook resulted in proceeds of more than $87.2 million related to the sale of Baycorp's 15 percent ownership interest. The agreement also limited any accelerated decommissioning funding required to be funded by Baycorp for decommissioning as part of the sale process. NU received approximately $17 million in 2002 in connection with this agreement. This amount is included in the $38.7 million of pre-tax Seabrook-related gains included in other income/(loss).

VYNPC: On July 31, 2002, VYNPC consummated the sale of its nuclear generating plant to a subsidiary of Entergy Corporation (Entergy) for approximately $180 million. As part of the sale, Entergy assumed responsibility for decommissioning VYNPC's nuclear generating unit. In 2003, CL&P, PSNH and WMECO sold their collective 17 percent ownership interest in VYNPC. CL&P, PSNH and WMECO will continue to buy approximately 16 percent of the plant's output through March 2012 at a range of fixed prices.

15. Segment Information

NU is organized between the Utility Group and NU Enterprises businesses based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which they operate. Based on different information that is reviewed by NU's new chief operating decision maker on January 1, 2004, separate detailed information regarding the Utility Group's transmission businesses and NU Enterprises' merchant energy business is now included in the following segment information. Segment information for all periods has been restated to conform to the current presentation except for total asset information for the transmission business segment as this information is not available.

The Utility Group segment, including both the regulated electric distribution and transmission businesses, as well as the gas distribution business comprised of Yankee Gas, represents approximately 69 percent, 72 percent, and 78 percent of NU's total revenues for the years ended December 31, 2004, 2003 and 2002, respectively, and includes the operations of the regulated electric utilities, CL&P, PSNH and WMECO, whose complete financial statements are included in NU's report on Form 10-K. PSNH's distribution segment includes generation activities. Also included in NU's combined report on Form 10-K is detailed information regarding CL&P's, PSNH's, and WMECO's transmission businesses. Utility Group revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

The NU Enterprises merchant energy business segment includes Select Energy, NGC, the generation operations of HWP, and their respective subsidiaries, while the NU Enterprises services and other business segment includes SESI, NGS, Woods Network, and their respective subsidiaries and intercompany eliminations. The results of NU Enterprises parent are also included within services and other.

Select Energy has served a portion of CL&P's transitional standard offer (TSO) or standard offer load for 2004, 2003 and 2002. Total Select Energy revenues from CL&P for CL&P's standard offer load, TSO load and for other transactions with CL&P, represented $611.3 million or 21 percent for the year ended December 31, 2004, approximately $688 million or 27 percent for the year ended December 31, 2003, and approximately $631 million or 35 percent for the year ended December 31, 2002, of total NU Enterprises' revenues. Total CL&P purchases from Select Energy are eliminated in consolidation.

WMECO's purchases from Select Energy for standard offer and default service and for other transactions with Select Energy represented approximately $108.5 million, $143 million and $14 million of total NU Enterprises' revenues for the years ended December 31, 2004, 2003 and 2002, respectively. Total WMECO purchases from Select Energy are eliminated in consolidation.

Select Energy revenues related to contracts with NSTAR companies represented $300.2 million or 11 percent of total NU Enterprises' revenues for the year ended December 31, 2004. Select Energy also provides basic generation service in the New Jersey and Maryland market. Select Energy revenues related to these contracts represented $334.2 million or 12 percent of total NU Enterprises' revenues for the year ended December 31, 2004, $380.4 million or 15 percent for the year ended December 31, 2003 and approximately $207.4 million or 12 percent for the year ended December 31, 2002. No other individual customer represented in excess of 10 percent of NU Enterprises' revenues for the years ended December 31, 2004, 2003, or 2002.

Other in the NU consolidated tables includes the results for Mode 1 Communications, Inc., an investor in NEON, the results of the non-energy-related subsidiaries of Yankee (Yankee Energy Services Company, RMS, Yankee Energy Financial Services, and NorConn Properties, Inc.), the non-energy operations of HWP, the results of NU's parent and service companies, and write-downs of certain of the company's investments. Interest expense included in other primarily relates to the debt of NU parent. Other includes after-tax investment write-downs totaling $8.8 million in 2004 and $11 million in 2002 related to Acumentrics and NEON. No investment write-downs related to Acumentrics or NEON were recorded in 2003. Virtually all of the assets and liabilities of RMS were sold on June 30, 2004.

NU's segment information for the years ended December 31, 2004, 2003, and 2002 is as follows (some amounts between segment schedules may not agree due to rounding):

	For the Year Ended December 31, 2004						
	Utility Group						
	Distribution			NU			
(Millions of Dollars)	Electric	Gas	Transmission	Enterprises	Other	Eliminations	Totals
Operating revenues	$ 4,040.1	$ 407.8	$140.7	$ 2,855.1	$ 289.6	$(1,046.6)	$ 6,686.7
Depreciation and amortization	(458.5)	(26.2)	(21.6)	(19.1)	(16.4)	13.7	(528.1)
Other operating expenses	(3,268.3)	(347.0)	(68.5)	(2,817.1)	(284.5)	1,039.7	(5,745.7)
Operating income/(loss)	313.3	34.6	50.6	18.9	(11.3)	6.8	412.9
Interest expense, net of AFUDC	(159.1)	(16.6)	(12.3)	(51.2)	(26.2)	11.9	(253.5)
Interest income	4.8	0.1	0.3	8.5	12.9	(12.9)	13.7
Other income/(loss), net	15.4	(1.0)	(0.2)	(5.6)	76.7	(84.5)	0.8
Income tax (expense)/benefit	(56.8)	(3.0)	(8.9)	14.3	15.3	(12.6)	(51.7)
Preferred dividends	(5.6)	—	—	—	—	—	(5.6)
Net income/(loss)	$ 112.0	$ 14.1	$ 29.5	$ (15.1)	$ 67.4	$ (91.3)	$ 116.6
Total assets (1)	$ 8,410.8	$1,147.9	$ —	$ 2,176.2	$4,313.1	$(4,392.2)	$11,655.8
Cash flows for total investments in plant	$ 390.0	$ 56.6	$163.9	$ 17.6	$ 15.7	$ —	$ 643.8

	For the Year Ended December 31, 2003						
	Utility Group						
	Distribution			NU			
(Millions of Dollars)	Electric	Gas	Transmission	Enterprises	Other	Eliminations	Totals
Operating revenues	$3,865.8	$ 361.5	$117.9	$2,574.8	$ 257.9	$(1,108.7)	$ 6,069.2
Depreciation and amortization	(483.8)	(23.4)	(18.7)	(19.6)	(14.2)	10.3	(549.4)
Other operating expenses	(3,072.1)	(311.7)	(51.9)	(2,509.4)	(238.2)	1,087.7	(5,095.6)
Operating income/(loss)	309.9	26.4	47.3	45.8	5.5	(10.7)	424.2
Interest expense, net of AFUDC	(166.1)	(13.1)	(3.5)	(49.6)	(23.5)	9.3	(246.5)
Interest income	3.8	—	0.1	8.0	9.4	(9.5)	11.8
Other income/(loss), net	(0.2)	(2.4)	(0.9)	(5.6)	90.9	(93.9)	(12.1)
Income tax (expense)/benefit	(44.8)	(3.6)	(14.8)	(2.0)	14.6	(0.1)	(50.7)
Preferred dividends	(5.6)	—	—	—	—	—	(5.6)
Income/(loss) before cumulative effect of accounting change	97.0	7.3	28.2	(3.4)	96.9	(104.9)	121.1
Cumulative effect of accounting change, net of tax benefit	—	—	—	—	(4.7)	—	(4.7)
Net income/(loss)	$ 97.0	$ 7.3	$ 28.2	$ (3.4)	$ 92.2	$ (104.9)	$ 116.4
Total assets (1)	$8,219.8	$1,068.6	$ —	$2,047.8	$4,314.8	$(4,434.5)	$11,216.5
Cash flows for total investments in plant	$ 365.8	$ 54.8	$ 96.3	$ 17.7	$ 29.0	$ —	$ 563.6

(1) Information for segmenting total assets between electric distribution and transmission is not available at December 31, 2004 or December 31, 2003. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution columns above.

	For the Year Ended December 31, 2002						
	Utility Group						
	Distribution			NU			
(Millions of Dollars)	Electric	Gas	Transmission	Enterprises	Other	Eliminations	Totals
Operating revenues	$3,701.3	$ 282.0	$122.1	$1,800.8	$ 324.3	$ (993.5)	$ 5,237.0
Depreciation and amortization	(600.1)	(24.0)	(18.0)	(21.6)	(18.8)	7.9	(674.6)
Other operating expenses	(2,701.4)	(218.1)	(46.4)	(1,818.5)	(299.2)	980.4	(4,103.2)
Operating income/(loss)	399.8	39.9	57.7	(39.3)	6.3	(5.2)	459.2
Interest expense, net of AFUDC	(182.5)	(14.2)	(1.9)	(43.9)	(35.5)	7.5	(270.5)
Interest income	4.1	0.1	--	6.5	7.7	(7.5)	10.9
Other income/(loss), net	16.7	(0.9)	(1.1)	(6.0)	161.9	(137.7)	32.9
Income tax (expense)/benefit	(107.4)	(7.3)	0.9	29.5	10.4	(0.9)	(74.8)
Preferred dividends	(5.6)	—	--	—	—	—	(5.6)
Net income/(loss)	$ 125.1	$ 17.6	$ 55.6	$ (53.2)	$ 150.8	$ (143.8)	$ 152.1
Cash flows for total investments in plant	$ 333.5	$ 67.6	$ 57.9	$ 21.0	$ 30.5	$ —	$ 510.5

NU Enterprises' segment information for the years ended December 31, 2004, 2003, and 2002 is as follows. Eliminations are included in the services and other columns.

	NU Enterprises — For the Year Ended December 31, 2004		
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$2,580.5	$274.6	$2,855.1
Depreciation and amortization	(17.2)	(1.9)	(19.1)
Other operating expenses	(2,538.5)	(278.6)	(2,817.1)
Operating income	24.8	(5.9)	18.9
Interest expense	(43.8)	(7.4)	(51.2)
Interest income	1.6	6.9	8.5
Other (loss)/income, net	(2.0)	(3.6)	(5.6)
Income tax (expense)/benefit	7.3	7.0	14.3
Net income/(loss)	(12.1)	(3.0)	(15.1)
Total assets	$1,886.5	$289.7	$2,176.2
Cash flows for total investments in plant	$ 15.8	$ 1.8	$ 17.6

	NU Enterprises — For the Year Ended December 31, 2003		
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$2,345.6	$229.2	$2,574.8
Depreciation and amortization	(17.7)	(1.9)	(19.6)
Other operating expenses	(2,285.9)	(223.5)	(2,509.4)
Operating income	42.0	3.8	45.8
Interest expense	(42.4)	(7.2)	(49.6)
Interest income	0.8	7.2	8.0
Other (loss)/income, net	(5.7)	0.1	(5.6)
Income tax (expense)/benefit	(0.2)	(1.8)	(2.0)
Net income/(loss)	(5.5)	2.1	(3.4)
Total assets	$1,776.7	$271.1	$2,047.8
Cash flows for total investments in plant	$ 17.7	$ —	$ 17.7

	NU Enterprises — For the Year Ended December 31, 2002		
(Millions of Dollars)	Merchant Energy	Services and Other	Totals
Operating revenues	$1,619.5	$181.3	$1,800.8
Depreciation and amortization	(20.0)	(1.6)	(21.6)
Other operating expenses	(1,637.2)	(181.3)	(1,818.5)
Operating income	(37.7)	(1.6)	(39.3)
Interest expense	(39.4)	(4.5)	(43.9)
Interest income	1.5	5.0	6.5
Other (loss)/income, net	(5.5)	(0.5)	(6.0)
Income tax (expense)/benefit	28.7	0.8	29.5
Net income/(loss)	(52.4)	(0.8)	(53.2)
Cash flows for total investment in plant	$ 21.0	$ —	$ 21.0

16. Restatement of Previously Issued Financial Statements

NU concluded that it incorrectly classified as unrestricted cash from counterparties amounts that should have been classified as cash and cash equivalents at December 31, 2003. These corrections reclassified unrestricted cash from counterparties to cash and cash equivalents because those funds were unrestricted and were used to fund or were available to fund the company's operations. The December 31, 2003 consolidated balance sheet has been restated for these corrections and a correction to decrease derivative assets and liabilities by the same amount in order to eliminate certain intercompany derivative assets and liabilities.

The effects of the revisions on the consolidated balance sheet as of December 31, 2003 and the consolidated statement of cash flows for the year ended December 31, 2003 are summarized in the following tables (in thousands):

	At December 31, 2003	
Consolidated Balance Sheet	Previously Reported	As Restated
Cash and cash equivalents	$ 37,196	$ 43,372
Unrestricted cash from counterparties	46,496	—
Derivative assets — current (1)	301,194	249,117
Accounts payable	768,783	728,463
Derivative liabilities — current (1)	164,689	112,612

(1) The 2003 derivative assets and derivative liabilities balances have been reclassified to conform to the current year's presentation. See reclassification below.

	For the Year Ended December 31, 2003	
Consolidated Statement of Cash Flows	Previously Reported	As Restated
Income before preferred dividends of subsidiary	$126,711	$126,711
Adjustments to reconcile net cash flows provided by operating activities:		
Unrestricted cash from counterparties	(29,606)	—
Other current assets	(24,863)	8,285
Accounts payable	(7,436)	(30,866)
Other current liabilities	100,039	90,928
Other operating activities	408,727	398,356
Net cash flows provided by operating activities	573,572	593,414
Net decrease in cash and cash equivalents	(13,137)	(6,961)
Cash and cash equivalents — end of year	$ 37,196	$ 43,372

Additionally, certain reclassifications of prior years' data have been made to conform with the current year's presentation. These reclassifications are summarized in the following tables (in thousands):

	At December 31, 2003	
	Previously Reported	As Reclassified
Derivative assets — current (1)	$ 249,117	$ 116,305
Derivative assets — long-term	—	132,812
	249,117	249,117
Derivative liabilities — current (1)	112,612	51,117
Derivative liabilities — long-term	—	61,495
	112,612	112,612
Accumulated deferred income taxes	1,287,354	1,277,309
Accrued taxes	51,598	50,881
Other current liabilities (2)	203,080	213,842
	$1,542,032	$1,542,032

(1) The 2003 derivative assets and derivative liabilities balances have been restated from amounts previously reported.

(2) Other current liabilities as previously reported excludes $46.5 million of counterparty deposits, which are now separately disclosed.

Reclassifications to income statement amounts are as follows:

	For Year Ended December 31, 2003	
	Previously Reported	As Reclassified
Fuel, purchased and net interchange power	$3,730,416	$3,735,154
Other	900,437	953,026
Maintenance	232,030	174,703
Amortization	182,675	191,805
Income tax expense	59,862	50,732

	For Year Ended December 31, 2002	
	Previously Reported	As Reclassified
Fuel, purchased and net interchange power	$3,046,781	$3,048,813
Other	752,482	815,212
Maintenance	263,487	198,725
Amortization	312,955	320,409
Income tax expense	82,304	74,850

Consolidated Statements Of Quarterly Financial Data (Unaudited)

	Quarter Ended (a)			
(Thousands of Dollars, except per share information)	March 31,	June 30,	September 30,	December 31,
2004				
Operating Revenues	**$1,838,287**	**$1,524,666**	**$1,667,985**	**$1,655,761**
Operating Income	**172,788**	**96,201**	**35,558**	**108,405**
Net Income/(Loss)	**67,442**	**23,992**	**(7,908)**	**33,062**
Basic and Fully Diluted Earnings/(Loss) Per Common Share	**0.53**	**0.19**	**(0.06)**	**0.26**
2003				
Operating Revenues	$1,584,183	$1,330,038	$1,640,117	$1,514,818
Operating Income	160,918	103,703	127,315	32,300
Income/(Loss) Before Cumulative Effect of Accounting Change	60,204	26,869	43,979	(9,900)
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	—	(4,741)	—
Net Income/(Loss)	60,204	26,869	39,238	(9,900)
Basic and Fully Diluted Earnings per Common Share:				
Income/(Loss) Before Cumulative Effect of Accounting Change	$ 0.47	$ 0.21	$ 0.35	$ (0.08)
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	—	(0.04)	—
Net Income/(Loss)	$ 0.47	$ 0.21	$ 0.31	$ (0.08)

(a) The summation of quarterly data may not equal annual data due to rounding.

Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and share information)	2004	2003	2002	2001	2000
Balance Sheet Data:					
Property, Plant and Equipment, Net	**$ 5,864,161**	$ 5,429,916	$ 5,049,369	$ 4,472,977	$ 3,547,215
Total Assets (a) (b)	**11,655,834**	11,216,487	10,764,880	10,331,923	10,217,149
Total Capitalization (c)	**5,293,644**	4,926,587	4,670,771	4,576,858	4,739,417
Obligations Under Capital Leases (c)	**14,806**	15,938	16,803	17,539	159,879
Income Data:					
Operating Revenues	**$ 6,686,699**	$ 6,069,156	$ 5,237,000	$ 5,760,949	$ 5,876,620
Income Before Cumulative Effect of Accounting Changes and Extraordinary Loss, Net of Tax Benefits	**116,588**	121,152	152,109	265,942	205,295
Cumulative Effect of Accounting Changes, Net of Tax Benefits	**—**	(4,741)	—	(22,432)	—
Extraordinary Loss, Net of Tax Benefit	**—**	—	—	—	(233,881)
Net Income/(Loss)	**$ 116,588**	$ 116,411	$ 152,109	$ 243,510	$ (28,586)
Common Share Data:					
Basic and Fully Diluted Earnings Per Common Share:					
Income Before Cumulative Effect of Accounting Changes and Extraordinary Loss, Net of Tax Benefits	**$ 0.91**	$ 0.95	$ 1.18	$ 1.97	$ 1.45
Cumulative Effect of Accounting Changes, Net of Tax Benefits	**—**	(0.04)	—	(0.17)	—
Extraordinary Loss, Net of Tax Benefit	**—**	—	—	—	(1.65)
Net Income/(Loss)	**$ 0.91**	$ 0.91	$ 1.18	$ 1.80	$ (0.20)
Basic Common Shares Outstanding (Average)	**128,245,860**	127,114,743	129,150,549	135,632,126	141,549,860
Fully Diluted Common Shares Outstanding (Average)	**128,396,076**	127,240,724	129,341,360	135,917,423	141,967,216
Dividends Per Share	**$ 0.63**	$ 0.58	$ 0.53	$ 0.45	$ 0.40
Market Price — Closing (high) (d)	**$ 20.10**	$ 20.17	$ 20.57	$ 23.75	$ 24.25
Market Price — Closing (low) (d)	**$ 17.30**	$ 13.38	$ 13.20	$ 16.80	$ 18.25
Market Price — Closing (end of year) (d)	**$ 18.85**	$ 20.17	$ 15.17	$ 17.63	$ 24.25
Book Value Per Share (end of year)	**$ 17.80**	$ 17.73	$ 17.33	$ 16.27	$ 15.43
Tangible Book Value Per Share (end of year)	**$ 15.17**	$ 15.05	$ 14.62	$ 13.71	$ 13.09
Rate of Return Earned on Average Common Equity (%)	**5.1**	5.2	7.0	11.2	(1.3)
Market-to-Book Ratio (end of year)	**1.1**	1.1	0.9	1.1	1.6
Capitalization:					
Common Shareholders' Equity	**44%**	46%	47%	46%	47%
Preferred Stock (c) (e)	**2**	2	3	3	4
Long-Term Debt (c)	**54**	52	50	51	49
	100%	100%	100%	100%	100%

(a) Total assets were not adjusted for cost of removal prior to 2002.

(b) Includes effects of restatements described in Note 16.

(c) Includes portions due within one year.

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

(e) Excludes $100 million of Monthly Income Preferred Securities.

CONSOLIDATED SALES STATISTICS (UNAUDITED)

	2004	2003	2002	2001	2000
Revenues: (Thousands)					
Utility Group:					
Residential	**$1,707,434**	$1,669,199	$1,512,397	$1,490,487	$1,469,439
Commercial	**1,429,608**	1,411,881	1,298,939	1,310,701	1,265,219
Industrial	**513,999**	514,076	485,591	544,806	560,821
Other Utilities	**344,254**	405,120	567,608	854,002	1,343,595
Streetlighting and Railroads	**41,976**	44,977	43,679	43,889	45,998
Miscellaneous and eliminations	**143,631**	(61,364)	(84,513)	52,794	55,860
Total Electric	**4,180,902**	3,983,889	3,823,701	4,296,679	4,740,932
Total Gas	**407,812**	361,450	281,206	378,033	251,233
Total – Utility Group	**$4,588,714**	$4,345,339	$4,104,907	$4,674,712	$4,992,165
NU Enterprises:					
Retail	**$ 857,355**	$ 660,145	$ 508,734	$ 209,838	$ 132,027
Wholesale (a)	**1,722,603**	1,684,448	1,108,370	1,675,647	1,654,487
Generation	**196,191**	185,493	170,143	184,878	184,106
Services	**323,433**	269,045	220,638	213,996	126,978
Miscellaneous and eliminations	**(244,419)**	(224,340)	(207,062)	(209,435)	(207,895)
Total – NU Enterprises	**$2,855,163**	$2,574,791	$1,800,823	$2,074,924	$1,889,703
Other miscellaneous and eliminations	**(757,178)**	(850,974)	(668,730)	(988,687)	(1,005,248)
Total	**$6,686,699**	$6,069,156	$5,237,000	$5,760,949	$5,876,620
Utility Group Sales: (kWh – Millions)					
Residential	**14,866**	14,824	13,923	13,322	12,940
Commercial	**14,710**	14,471	14,103	13,751	13,023
Industrial	**6,274**	6,223	6,265	6,790	7,130
Other Utilities	**23,778**	18,791	82,538	48,336	42,234
Streetlighting and Railroads	**348**	348	344	332	333
Total	**59,976**	54,657	117,173	82,531	75,660
Utility Group Customers: (Average)					
Residential	**1,659,419**	1,631,582	1,614,239	1,610,154	1,576,068
Commercial	**194,233**	186,792	183,577	171,218	166,114
Industrial	**7,752**	7,644	7,763	7,730	7,701
Other	**3,930**	3,858	3,949	3,969	3,917
Total Electric	**1,865,334**	1,829,876	1,809,528	1,793,071	1,753,800
Gas	**194,212**	192,816	190,855	190,998	185,328
Total	**2,059,546**	2,022,692	2,000,383	1,984,069	1,939,128
Utility Group – Average Annual Use Per Residential Customer (kWh)	**8,960**	9,087	8,611	8,251	8,233
Utility Group – Average Annual Bill Per Residential Customer	**$ 1,028.97**	$ 1,024.20	$ 934.90	$ 923.70	$ 934.94
Utility Group Average Revenue Per kWh:					
Residential	**11.48¢**	11.27¢	10.86¢	11.20¢	11.36¢
Commercial	**9.70**	9.74	9.18	9.48	9.65
Industrial	**8.19**	8.26	7.75	8.10	7.95

(a) Operating income amounts for 2004 through 2002 reflect the application of EITF Issue No. 03-11. Operating revenue amounts prior to 2002 have not been reclassified.

Trustees and Officers

Northeast Utilities Trustees as of March 15, 2005

Richard H. Booth *(1) (2)*
President and Chief Executive Officer, Hartford Steam Boiler Inspection & Insurance Company

Cotton Mather Cleveland
President, Mather Associates

Sanford Cloud, Jr.
Former President and Chief Executive Officer, The National Conference for Community and Justice

James F. Cordes *(1)*
Retired, Former Executive Vice President, The Coastal Corporation

E. Gail de Planque *(1)*
President, Strategy Matters, Inc.

John G. Graham *(1) (2)*
Adjunct Professor of Law, Rutgers Law School

Elizabeth T. Kennan *(1)*
President Emeritus, Mount Holyoke College

Robert E. Patricelli
Chairman, President and Chief Executive Officer, Women's Health USA, Inc. and Evolution Benefits, Inc.

John F. Swope *(1)*
Attorney

Northeast Utilities Officers as of March 15, 2005

Charles W. Shivery
Chairman of the Board, President and Chief Executive Officer

Lawrence E. De Simone
President – Competitive Group

Cheryl W. Grisé
President – Utility Group

Leon J. Olivier
President – Transmission Group

Gregory B. Butler
Senior Vice President, Secretary and General Counsel

David R. McHale
Senior Vice President and Chief Financial Officer

Randy A. Shoop
Vice President and Treasurer

John P. Stack
Vice President – Accounting and Controller

O. Kay Comendul
Assistant Secretary

Patricia C. Cosgel
Assistant Treasurer – Finance

Northeast Utilities System Officers as of March 15, 2005

Northeast Utilities Service Company Officers

Charles W. Shivery
Chairman, President and Chief Executive Officer

Lawrence E. De Simone
President – Competitive Group

Cheryl W. Grisé
President – Utility Group

Leon J. Olivier
President – Transmission Group

Gregory B. Butler
Senior Vice President, Secretary and General Counsel

David R. McHale
Senior Vice President and Chief Financial Officer

David H. Boguslawski
Vice President – Transmission Strategy and Operations

Mary Jo Keating
Vice President – Corporate Communications

Jeffrey R. Kotkin
Vice President – Investor Relations

Kerry J. Kuhlman
Vice President – Shared Services

Jean M. LaVecchia
Vice President – Human Resources

Margaret L. Morton
Vice President – Governmental Affairs

Randy A. Shoop
Vice President and Treasurer

John P. Stack
Vice President – Accounting and Controller

Lisa J. Thibdaue
Vice President – Regulatory and Governmental Affairs

Electric & Gas Operating Company Officers

CL&P – The Connecticut Light and Power Company

PSNH – Public Service Company of New Hampshire

WMECO – Western Massachusetts Electric Company

Yankee – Yankee Gas Services Company

Cheryl W. Grisé
Chief Executive Officer, CL&P, PSNH, WMECO and Yankee

Gary A. Long
President and Chief Operating Officer, PSNH

Raymond P. Necci
President and Chief Operating Officer, CL&P

Rodney O. Powell
President and Chief Operating Officer, WMECO

Dennis E. Welch
President and Chief Operating Officer, Yankee

Gregory B. Butler
Senior Vice President, Secretary and General Counsel, Yankee

David R. McHale
Senior Vice President and Chief Financial Officer, CL&P, PSNH, WMECO and Yankee

Christopher L. Beschler
Vice President – Operations, Yankee

David H. Boguslawski
Vice President-Transmission Strategy and Operations, CL&P, PSNH and WMECO

Peter J. Clarke
Vice President – Customer Operations and Relations, CL&P

Dana L. Louth
Vice President – Energy Delivery Services, CL&P

John M. MacDonald
Vice President – Operations, PSNH

James A. Muntz
Vice President – Transmission Projects, CL&P, PSNH and WMECO

Paul E. Ramsey
Vice President – Customer Services, PSNH

Randy A. Shoop
Vice President and Treasurer, CL&P, PSNH, WMECO and Yankee

John P. Stack
Vice President – Accounting and Controller, CL&P, PSNH, WMECO and Yankee

Roger C. Zaklukiewicz
Vice President – Transmission Technical Support, CL&P, PSNH and WMECO

O. Kay Comendul
Secretary, CL&P and PSNH

Patricia A. Wood
Clerk, WMECO

Competitive Company Officers

NUEI – NU Enterprises, Inc.

NGC – Northeast Generation Company

NGS – Northeast Generation Services Company

Select – Select Energy, Inc.

SESI – Select Energy Services, Inc.

Lawrence E. De Simone
President and Chief Executive Officer, NUEI
Chairman, President and Chief Executive Officer, Select
Chairman and Chief Executive Officer, NGC, NGS and SESI

William J. Nadeau
President, NGC
Vice President and Chief Operating Officer, NGS

James B. Redden
President, SESI

William J. Quinlan
Acting President, NGS
Acting Chief Operating Officer, NUEI, NGC and Select

Stephen J. Fabiani
Vice President – Retail Sales and Marketing, Select

Linda A. Jensen
Vice President – Finance, Treasurer and Secretary, SESI

John M. Boardman
Controller, Select

Frederic Lee Klein
Secretary, NUEI, NGC, NGS and Select

(1) *Member of the Audit Committee of the Board of Trustees who is independent from the Company as defined by Section 301 of the Sarbanes-Oxley Act of 2002.*

(2) *Audit Committee Financial Expert as defined under Section 407 of the Sarbanes-Oxley Act of 2002.*

Shareholders

As of December 31, 2004, there were 56,531 common shareholders of record of Northeast Utilities holding an aggregate of 151,230,981 common shares.

Common Share Information

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

Year	Quarter	High	Low	Quarterly Dividend per Share
2004	**First**	**$20.10**	**$18.35**	**$0.15**
	Second	**$19.50**	**$17.70**	**$0.15**
	Third	**$19.49**	**$18.50**	**$0.1625**
	Fourth	**$20.03**	**$17.30**	**$0.1625**
2003	First	$16.06	$13.38	$0.1375
	Second	$16.77	$13.98	$0.1375
	Third	$18.28	$15.76	$0.15
	Fourth	$20.17	$18.12	$0.15

Transfer Agent and Registrar

The Bank of New York
Investor Relations Department
P.O. Box 11258
Church Street Station
New York, NY 10286-1258
1-800-999-7269

Annual Meeting

The Annual Meeting of Shareholders of Northeast Utilities will be held at 10:30 a.m. on May 10, 2005, at the offices of Public Service Company of New Hampshire, Energy Park, 780 North Commercial Street, Manchester, New Hampshire.

Compliance with New York Stock Exchange Corporate Governance Rules

The Company's Form 10-K for 2004 contained the certification required by Section 302 of the Sarbanes-Oxley Act of 2002, and on June 9, 2004, the Company's Chief Executive Officer provided the New York Stock Exchange with the required annual written certification that he was not aware of any violations by the Company of the Exchange's corporate governance listing standards.

Form 10-K

Northeast Utilities will provide shareholders a copy of its 2004 Annual Report to the Securities and Exchange Commission on Form 10-K, including the financial statements and schedules thereto, without charge, upon receipt of a written request sent to:

O. Kay Comendul
Assistant Secretary
Northeast Utilities
P.O. Box 270
Hartford, Connecticut 06141-0270

Northeast Utilities is the parent company of the NU system (collectively referred to as NU). NU operates New England's largest energy delivery system with 1,865,334 million electric customers in Connecticut, New Hampshire and Massachusetts and 194,212 natural gas customers in Connecticut. It is one of the largest competitive energy suppliers in New England.

Current NU subsidiaries are listed below:

Electric and Gas Operating Subsidiaries

The Connecticut Light and Power Company

Public Service Company of New Hampshire

Western Massachusetts Electric Company

Yankee Gas Services Company,
a subsidiary of Yankee Energy System, Inc.

Competitive Subsidiaries

Holyoke Water Power Company *(generation ownership)*

NU Enterprises, Inc. *(unregulated businesses holding company)*

Mode 1 Communications, Inc. *(telecommunications)*

Northeast Generation Company *(generation ownership)*

Northeast Generation Services Company *(generation services)*

Select Energy, Inc. *(energy supply)*

Select Energy Services, Inc. *(energy services)*

Support Subsidiary

Northeast Utilities Service Company *(systemwide services)*

Realty Subsidiaries

NorConn Properties, Inc. *(Connecticut)*

Properties, Inc. *(New Hampshire)*

The Quinnehtuk Company *(Massachusetts)*

The Rocky River Realty Company *(Connecticut)*

Financing Subsidiaries

CL&P Funding LLC

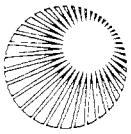
CL&P Receivables Corporation

PSNH Funding LLC

PSNH Funding LLC 2

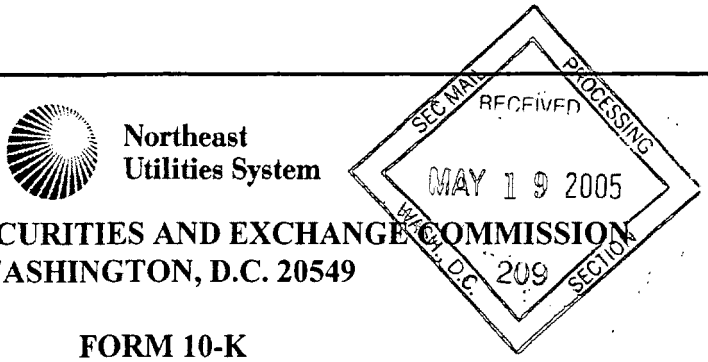
WMECO Funding LLC

Design: Cole Design Group, Canton, CT Major Photography: Al Ferreira Photography, Ltd., East Hartford, CT Printing: Allied Printing Services, Inc., Manchester, CT



Northeast Utilities

P.O. Box 270
Hartford, Connecticut 06141-0270
1 800.286.5000
www.nu.com



Northeast
Utilities System

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, 2004

OR

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

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary association) One Federal Street Building 111-4 Springfield, Massachusetts 01105 Telephone: (413) 785-5871	04-2147929
1-11419	**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 West 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
$2.05	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

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 registrants are accelerated filers (as defined in Rule 12b-2 of the 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 nonaffiliates, 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, 2004) was **$2,494,074,290** based on a closing sales price of **$19.47** per share for the 128,098,320 common shares outstanding on June 30, 2004. **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.

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated
Portions of Annual Reports of the following companies for the year ended December 31, 2004:	
Northeast Utilities	Part II
The Connecticut Light and Power Company	Part II
Public Service Company of New Hampshire	Part II
Western Massachusetts Electric Company	Part II
Portions of the Northeast Utilities Proxy Statement dated March 31, 2005	Part III

GLOSSARY OF TERMS

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

COMPANIES

Acumentrics	Acumentrics Corporation
Baycorp	Baycorp Holdings, LTD
Bechtel	Bechtel Power Corporation
BMC	BMC Energy LLC
Boulos	E. S. Boulos Company
CL&P	The Connecticut Light and Power Company
Con Edison	Consolidated Edison, Inc.
CRC	CL&P Receivables Corporation
CVEC	Connecticut Valley Electric Company, Inc.
CVPS	Central Vermont Public Service Corporation
CYAPC	Connecticut Yankee Atomic Power Company
DNCI	Dominion Nuclear Connecticut, Inc.
Entergy	Entergy Corporation
FPL	FPL Group, Inc.
Funding Companies	CL&P Funding LLC, PSNH Funding LLC, PSNH Funding LLC 2, and WMECO Funding LLC
Globix	Globix Corporation
HEC/CJTS	HEC/CJTS Energy Center, LLC
HEC/Tobyhanna	HEC/Tobyhanna Energy Project, LLC
HP&E	Holyoke Power and Electric
HWP	Holyoke Water Power Company
MGT	Meriden Gas Turbines, LLC
Mode 1	Mode 1 Communications
MYAPC	Maine Yankee Atomic Power Company
NAEC	North Atlantic Energy Corporation
NAESCO	North Atlantic Energy Service Corporation
NEON	NEON Communications, Inc.
NGC	Northeast Generation Company
NGS	Northeast Generation Services Company
NNECO	Northeast Nuclear Energy Company
NRG	NRG Energy, Inc.
NU or the company	Northeast Utilities
NU system	Northeast Utilities System
NU Enterprises or NUEI	NU Enterprises, Inc.
NUSCO	Northeast Utilities Service Company
PSNH	Public Service Company of New Hampshire
RMS	R.M. Services, Inc.
RRR	The Rocky River Realty Company
Select Energy	Select Energy, Inc.
SESI	Select Energy Services, Inc.
VYNPC	Vermont Yankee Nuclear Power Corporation
WMECO	Western Massachusetts Electric Company
Woods Electrical	Woods Electrical Co., Inc.
Woods Network	Woods Network Services, Inc.
YAEC	Yankee Atomic Electric Company
Yankee	Yankee Energy System, Inc.
Yankee Companies	CYAPC, MYAPC, VYNPC, and YAEC
Yankee Gas	Yankee Gas Services Company

GENERATING UNITS

Millstone 1	Millstone Unit No. 1, a 660 megawatt nuclear unit completed in 1970; Millstone 1 is currently in decommissioning status and was sold to a subsidiary of Dominion in March 2001.
Millstone 2	Millstone Unit No. 2, an 870 megawatt nuclear electric generating unit completed in 1975; Millstone 2 was sold to a subsidiary of Dominion in March 2001.
Millstone 3	Millstone Unit No. 3, a 1,154 megawatt nuclear electric generating unit completed in 1986; Millstone 3 was sold to a subsidiary of Dominion in March 2001.
Seabrook	Seabrook Unit No. 1, a 1,148 megawatt nuclear electric generating unit completed in 1986. Seabrook 1 went into service in 1990. Seabrook 1 was sold to a subsidiary of FPL in November 2002.

REGULATORS

CSC	Connecticut Siting Council
CDEP	Connecticut Department of Environmental Protection
DOE	United States Department of Energy
DPUC	Connecticut Department of Public Utility Control
DTE	Massachusetts Department of Telecommunications and Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
NHPUC	New Hampshire Public Utilities Commission
NRC	Nuclear Regulatory Commission
SEC	Securities and Exchange Commission

OTHER

1935 Act	Public Utility Holding Company Act of 1935
ABO	Accumulated Benefit Obligation
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
BFA	Business Finance Authority
CAAA	Clean Air Act Amendments of 1990
CTA	Competitive Transition Assessment
District Court	United States District Court for the Southern District of New York
EDIT	Excess Deferred Income Taxes
EITF	Emerging Issues Task Force
EMF	Electric and Magnetic Fields
Energy Act	Energy Policy Act of 1992
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
IERM	Infrastructure Expansion Rate Mechanism
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation No.
FMCC	Federally Mandated Congestion Charges
FPPAC	Fuel and Purchased-Power Adjustment Clause
FSP	FASB Staff Position
GSC	Generation Service Charge
Incentive Plan	Northeast Utilities Incentive Plan
IPP	Independent Power Producer
ISO-NE	New England Independent System Operator
ITC	Investment Tax Credits
kWh	Kilowatt-hour
LICAP	Locational Installed Capacity
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LNS	Local Network Service
LOC	Letter of Credit

Merger Agreement	Agreement and Plan of Merger, as amended and restated as of January 11, 2000, between NU and Con Edison
MGP	Manufactured Gas Plant
MW	Megawatts
NEPOOL	New England Power Pool
NPDES	National Pollutant Discharge Elimination System
NYMEX	New York Mercantile Exchange
OCC	Office of Consumer Counsel
O&M	Operation and Maintenance
PBO	Projected Benefit Obligation
PBOP	Postretirement Benefits Other Than Pensions
PCRBs	Pollution Control Revenue Bonds
Money Pool or Pool	Northeast Utilities Money Pool
Restructuring Settlement	"Agreement to Settle PSNH Restructuring"
RMR	Reliability Must Run
RNS	Regional Network Service
ROC	Risk Oversight Council
ROE	Return on Equity
RRBs	Rate Reduction Bonds
RRCs	Rate Reduction Certificates
RTO	Regional Transmission Organization
SBC	System Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SMD	Standard Market Design
SPE	Special Purpose Entity
TCC	Transmission Congestion Contracts
TS/DS	Transition Energy Service/Default Energy Service
TSO	Transitional Standard Offer
VIE	Variable Interest Entity
VRP	Voluntary Retirement Program

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

2004 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

PART I

Item 1. Business

The Northeast Utilities System

Northeast Utilities (NU) is the parent company of the Northeast Utilities system (the NU system). The NU system furnishes franchised retail electric service to approximately 1.9 million customers in 419 cities and towns in Connecticut, New Hampshire and western Massachusetts through three of NU's wholly-owned subsidiaries (The Connecticut Light and Power Company [CL&P], Public Service Company of New Hampshire [PSNH] and Western Massachusetts Electric Company [WMECO]).

The NU system also furnishes franchised retail natural gas service in a large part of Connecticut through Yankee Gas Services Company (Yankee Gas), a subsidiary of Yankee Energy System, Inc. (Yankee), the largest natural gas distribution company in Connecticut. Yankee Gas serves approximately 194,000 residential, commercial and industrial customers in 71 cities and towns in Connecticut, including large portions of the central and southwest sections of the state.

NU, through its wholly-owned subsidiary, NU Enterprises, Inc. (NUEI), owns a number of competitive energy and related businesses, including Northeast Generation Company (NGC), Northeast Generation Services Company (NGS), Select Energy, Inc. (Select Energy), Select Energy Services, Inc. (SESI), Mode 1 Communications, Inc. (Mode 1) and Woods Network Services, Inc. (Woods Network). Holyoke Water Power Company (HWP), a subsidiary of NU, is a resource of NUEI through an output contract with Select Energy. For information regarding the activities of these subsidiaries, see "Competitive System Businesses."

Several other wholly-owned subsidiaries of NU provide support services for the NU system companies and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, information technology, engineering, financial, legal, operational, planning, purchasing and other services to the NU system companies. Three other subsidiaries construct, acquire or lease some of the property and facilities used by the NU system companies.

The NU system is regulated in virtually all aspects of its business by various federal and state agencies, including the Securities and Exchange Commission (SEC), the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each company operates, including the Connecticut Department of Public Utility Control (DPUC), the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (DTE). In recent years, there has been significant legislative and regulatory activity changing the nature of regulation of the industry. For more information regarding these restructuring initiatives, see "Regulated Electric Operations."

For information regarding each of the NU system's reportable segments, see Footnote 15, "Segment Information" contained within NU's 2004 Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

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

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (Reform Act), NU and its reporting subsidiaries are hereby filing cautionary statements identifying important factors that could cause NU or its subsidiaries' actual results to differ materially from those projected in forward looking statements (as such term is defined in the Reform Act) made by or on behalf of NU or its subsidiaries in this combined Form 10-K, in any subsequent filings with the SEC, in presentations, in response to questions, or otherwise. Any statements that express or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events, or performance (often, but not always, through the use of words or phrases such as estimate, expect, anticipate, intend, plan, believe, forecast, should, could and similar expressions) are not statements of historical facts and may be forward looking. Forward looking statements involve estimates, assumptions and uncertainties that could cause actual results to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that could cause NU or its subsidiaries' actual results to differ materially from those contained in forward looking statements of NU or its subsidiaries made by or on behalf of NU or its subsidiaries.

Any forward looking statement speaks only as of the date on which such statement is made, and NU and its subsidiaries 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.

Some important factors that could cause actual results or outcomes to differ materially from those discussed in the forward looking statements include, but are not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, expiration or initiation of significant energy supply contracts, changes in levels of capital expenditures, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, effectiveness of NU's risk management policies and procedures, changes in accounting standards and financial reporting regulations, fluctuations in the value of electricity positions, changes in the ability to sell electricity positions and close out natural gas positions at anticipated margins, obtaining new contracts at anticipated volumes and margins, terrorist attacks on domestic energy facilities, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in NU's reports to the SEC.

All such factors are difficult to predict, contain uncertainties which may materially affect actual results and are beyond the control of NU or its subsidiaries.

RISK FACTORS

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

Risks Related to Disposition of Wholesale Competitive and Services Businesses

On March 9, 2005, NU announced that it completed its previously announced comprehensive review of its competitive energy businesses and that it had decided that NUEI will exit the wholesale marketing business. NU has concluded that the wholesale merchant energy sector in the power pools between Maine and Maryland is becoming increasingly competitive and that NUEI's wholesale marketing business will be unable to attain the profit margins necessary to generate acceptable returns and cash flows. As a result, NUEI will explore a number of alternatives for exiting the wholesale marketing business, including selling the wholesale marketing franchise, selling existing contracts, restructuring longer term contracts and allowing shorter term contracts to expire without being renewed. NUEI's marketing subsidiary, Select Energy, will only bid on new full requirements wholesale contracts to improve the value of its book of business by reducing existing electric positions.

NU also concluded that NUEI's competitive energy services business are not central to NU's long-term strategy and do not meet the company's expectations of profitability. As a result, NU will explore ways to divest those businesses in a manner that maximizes their value. Those businesses include electrical, mechanical, telecommunications, commercial plumbing and performance contracting companies. NU will retain its competitive generation and retail energy marketing businesses because it believes that the assets and retail business are competitively positioned to create significant opportunities for those businesses over the next several years.

NU will retain its 1,443 megawatts of competitive generating assets because it expects that their value could increase significantly in the coming years. The competitive generating assets, which include pumped storage, hydroelectric and coal-fired units, are contained within NGC and HWP. NUEI also will retain NGS, which operates the NGC and HWP plants.

NU expects to record a charge in the first quarter of 2005 associated with the wholesale marketing and energy services businesses. The level of that charge will depend on a number of factors, including how the disposition of those businesses is accomplished. NU continues to work with the firm of Lazard Freres & Co., LLC on that process.

While the energy services businesses present a lower level of volatility and risk, the wholesale business, until disposed of, will continue to present financial risk to NU from a variety of perspectives. These include earnings volatility around Select Energy's portfolio of gas and electric resources procured to serve both existing and anticipated load: with the decision to dispose of this business, certain contracts within the portfolio will be accounted for on a mark to market, rather than accrual, basis. The earnings charge which NU expects to take referred to above may not be adequate to cushion future negative price movements which may occur. In addition, Select Energy's ability to function will continue to be dependant upon the financial reliability of its counterparties and its ability to manage its wholesale marketing portfolio of contracts and assets within acceptable risk parameters.

Risks Related to Retained Retail Competitive and Generation Businesses

The retail competitive energy business presents the same kinds of challenges as the wholesale competitive energy businesses but on a smaller scale. Select Energy generally acquires retail customers in smaller increments, which while requiring careful sourcing allows

energy assets to be acquired in smaller increments with less risk. However, fluctuations in prices, fuel costs, competitive conditions, regulations, weather, transmission costs, lack of market liquidity, plant outages and other factors can all impact the retail business adversely from time to time.

The competitive generation business is also subject to these risks. In addition, the future value of LICAP credits have not been determined and are subject to regulatory decision-making over which NU has no control.

Risks Associated With The Transmission and Distribution Operations Of NU's Utility Subsidiaries

Transmission. NU, primarily through its subsidiary CL&P, has undertaken a substantial transmission capital investment program over the past several years and expects to invest more than $1.5 billion in regulated electric transmission infrastructure from 2005 through 2009. Included in this amount is approximately $1.4 billion for costs associated with construction of two Connecticut 345 KV transmission lines from Norwalk to Middletown and Norwalk to Bethel; replacement of an undersea electric transmission line between Norwalk and Northport, New York; and two 115 KV underground transmission lines between Norwalk and Stamford, Connecticut. The regulatory approval process for these transmission projects has encompassed an extensive permitting, design and technical approval process. Various factors have resulted in increased cost estimates and delayed construction.

The projects are expected to help alleviate identified reliability issues in southwest Connecticut and to help reduce customers' costs in all of Connecticut. However, if, due to further regulatory or other delays, the projected in-service date for one or more of these projects is delayed, there may be increased risk of failures in the existing electricity transmission system in southwestern Connecticut and supply interruptions or blackouts may occur.

The successful implementation of NU's transmission construction plans is also subject to the risk that new legislation, regulations or judicial or regulatory interpretations of applicable law or regulations could impact NU's ability to meet its construction schedule and/or require NU to incur additional expenses, and may adversely affect its ability to achieve forecast levels of revenues.

Unless CL&P is able to increase rates to recover these construction costs on a timely basis, certain of NU's and CL&P's financial ratios may decline and CL&P's ability to pay dividends to NU to support its common dividend and interest requirements may be weakened.

Distribution. CL&P and WMECO procure energy for a substantial portion of their customers via requests for proposal on an annual, semi-annual or quarterly basis. There is a risk at any given solicitation that the solicitation will not be fully subscribed or that prices will be much higher than current prices. CL&P and WMECO receive approvals of recovery of these contract prices from the DPUC and DTE, respectively. While both regulators have consistently approved solicitation processes, results and recovery of costs, management cannot predict the outcome of future solicitation efforts or the regulatory proceedings related thereto.

Litigation-Related Risks

NU and its affiliates are engaged in litigation that could result in the imposition of large cash awards against them. This litigation includes civil lawsuits between Consolidated Edison, Inc. (Con Edison) and NU relating to the parties' October 13, 1999 Agreement and Plan of Merger and the termination of a decommissioning contract between the Connecticut Yankee Atomic Power Company (CYAPC), the stock of which is 49 percent owned by subsidiaries of NU, and Bechtel Power Corporation.

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

NU may also be subject to future litigation based on asserted or unasserted claims and cannot predict the outcome of any of these proceedings. Adverse outcomes in existing or future litigation could result in the imposition of substantial cash damage awards against us.

Risks Associated With Environmental Regulation

NU's subsidiaries' operations are subject to extensive federal, state and local environmental statutes, rules and regulations which regulate, among other things, air emissions, water discharges and the management of hazardous and solid waste. Compliance with these requirements requires NU 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 these legal requirements have been significant in the past and may increase in the future. If such costs do increase, this could have an adverse impact on NU's business and results of operations, financial position and cash flows.

If NU fails to comply with environmental laws and regulations, even if due to factors beyond its control or reinterpretations of existing requirements, such failure may also lead to the assessment of civil and/or criminal liability and fines.

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 NU. Revised or additional laws could result in significant additional expense and operating restrictions on NU's facilities or increased compliance costs which may not be fully recoverable in rates. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time.

REGULATED ELECTRIC OPERATIONS

Distribution and Sales

CL&P, PSNH and WMECO furnish retail franchise electric service in 149, 211 and 59 cities and towns in Connecticut, New Hampshire and Massachusetts, respectively. In December 2004, CL&P provided retail franchise service to approximately 1.2 million customers in Connecticut, PSNH provided retail service to approximately 475,000 customers in New Hampshire and WMECO served approximately 207,000 retail customers in Massachusetts.

The following table shows the sources of 2004 electric franchise retail revenues based on categories of customers:

	CL&P	PSNH	WMECO	Total NU System
Residential	48%	41%	46%	46%
Commercial	39%	39%	36%	39%
Industrial	11%	19%	17%	14%
Other	2%	1%	1%	1%
Total	100%	100%	100%	100%

The actual changes in retail kWh sales for the last two years and the forecasted retail sales growth estimates for the five-year period 2004 through 2009 for CL&P, PSNH and WMECO are set forth below:

	2004 over 2003	2003 over 2002	Forecast 2004-2009 Compound Rate in Growth
NU System	0.9%	3.6%	1.7%
CL&P	0.1%	3.3%	1.5%
PSNH	3.1%	4.7%	2.5%
WMECO	1.6%	2.6%	0.8%

Consolidated NU retail sales rose by 0.9 percent in 2004, compared with 2003. Residential electric sales were up 0.3 percent. Commercial sales were up by 1.7 percent for the year and industrial sales increased by 0.8 percent. Retail sales for CL&P, WMECO and PSNH were up 0.1 percent, 1.6 percent and 3.1 percent, respectively.

Regional and System Coordination

The NU electric utility subsidiaries and most other New England utilities are parties to an agreement (the Restated NEPOOL Agreement) which provides for coordinated planning and operation of the region's generation and transmission facilities. The Restated NEPOOL Agreement provides for (i) a pool-wide open access transmission tariff; (ii) the creation of an ISO; and (iii) a broader governance structure for the New England Power Pool (NEPOOL) and a more open, competitive market structure. Under these arrangements, ISO New England Inc. (ISO-NE), a non-profit corporation whose board of directors and staff are not controlled by or affiliated with market participants, ensures the reliability of the NEPOOL transmission system, administers the NEPOOL tariff and oversees the efficient and competitive functioning of the regional power market.

The NEPOOL tariff provides for nondiscriminatory open access to the regional transmission network at a single rate regardless of transmitting distance for all transactions. The rate is a formula rate, structured to ensure that each transmission provider under the NEPOOL tariff recovers its revenue requirements.

Open access transmission service over local transmission networks is provided by individual local transmission owners through their respective open access transmission tariffs. NU's local open access transmission tariff (Tariff No. 10) is also a formula rate which was recently restructured to ensure timely recovery of NU's revenue requirements. As a result of the comprehensive settlement in 2004 of certain issues concerning Tariff No. 10, NU's return on equity (ROE) for recovery of transmission revenue requirements cost was set at 11 percent, until such time as the FERC establishes an ROE for the regional transmission organization (RTO) tariff discussed below.

Transmission revenues are allocated between CL&P, HWP and its wholly-owned subsidiary, Holyoke Power and Electric Company (HP&E), WMECO and PSNH based upon a net revenue requirement allocation methodology. These companies are currently pursuing FERC approval of the net revenue allocation methodology.

Transmission Access and FERC Regulatory Changes

NU's electric utility subsidiaries' wholesale transmission revenues are based on rates and formulas that are approved by the FERC. Most of NU's wholesale transmission revenues are collected through a combination of the New England regional network service (RNS) tariff and NU's local network service (LNS) tariff. NU's LNS tariff is also reset on June 1st of each year to coincide with the change in RNS rates. Additionally, NU's LNS tariff provides for a true-up to actual costs which ensures that NU recovers its total transmission revenue requirements, including the allowed ROE. Through December 31, 2004, this true-up has resulted in the recognition of a $4.6 million regulatory liability for refund to electric distribution companies, including CL&P, PSNH and WMECO.

On October 31, 2003, ISO-NE, along with NU and six other New England transmission owning companies (the New England TOs), filed a proposal with the FERC to create an RTO for New England in compliance with a 1999 FERC order calling on all transmission owners to voluntarily join RTOs (Order 2000). In a separate filing made on November 4, 2003, the New England TOs requested, consistent with the FERC's pricing policy for RTOs, that the FERC approve a single ROE for regional and local transmission service rates that would consist of a proposed 12.8 percent base ROE as well as incentive adders of 0.5 percent for joining an RTO and 1.0 percent for constructing new transmission facilities approved by the RTO.

On March 24, 2004, the FERC issued an order conditionally accepting the New England RTO proposal, but set for hearing the determination of the appropriate base ROE for transmission rates under the RTO and the clarification as to which facilities the 1.0 percent incentive adder should apply. The 0.5 percent ROE adder was accepted for regional rates. The March 24 order also required a number of compliance filings which were made in June, August and September of 2004.

On November 3, 2004, the FERC issued an order that (i) determined that the New England transmission owners' methodology used to calculate the proposed ROE is appropriate, (ii) clarified the application of the 0.5 percent incentive adder for joining a RTO and reaffirmed the appropriateness of the 1.0 percent incentive adder for new investments, however, left still unresolved the type of investments to which the 1.0 percent incentive adder should apply, and (iii) approved certain compliance items that were required by the FERC's March 24, 2004 order.

While the order approved the methodology that had been proposed by the transmission owners for calculating the base ROE, it determined that the actual base ROE would be determined following conclusion of the ordered hearing, which commenced on January 25, 2005. As part of the hearing procedures, the New England TOs submitted supplemental testimony supporting their ROE proposal on January 10, 2005 that, among other things, updated the ROE calculations submitted with the November 2003 filing. An initial administrative law judge decision on these issues is expected in May 2005, and a final FERC ruling regarding these issues is expected by the first quarter of 2006.

In January 2005, the boards of the New England TOs (including the operating company boards of CL&P, WMECO and PSNH) voted affirmatively to approve activation of the RTO, which occurred on February 1, 2005. As of February 1, 2005, transmission rates will be adjusted to reflect the ROEs proposed by the New England TOs in the original RTO filing (12.8 plus requested 0.5 percent), subject to refunds to reflect the ROE resulting from the ultimate outcome of the hearings. Management cannot at this time predict the ultimate ROE that will be determined following the hearings.

CL&P, PSNH and WMECO are also expected to experience locational installed capacity (LICAP) charges subsequent to their implementation by the FERC. Because southwest Connecticut is a constrained area with insufficient generation, CL&P could see LICAP costs of several hundred million dollars. These costs would be recovered from customers through the federally mandated congestion charge (FMCC) mechanism. For further information on LICAP, see "Competitive System Businesses – Electric Generation."

Rates - General

CL&P, WMECO and PSNH have undergone fundamental changes in their business operations as a result of the restructuring of the electric industry in their respective jurisdictions. CL&P and WMECO have divested all of their generation assets and are now acting as transmission and distribution companies. PSNH has divested all ownership of nuclear generation. Under New Hampshire law, PSNH may not divest its fossil/hydro generation assets until April 2006 at the earliest; thereafter, divestiture may occur only if the NHPUC determines that such divestiture is in the economic interest of retail customers of PSNH.

CL&P, PSNH and WMECO have received regulatory orders allowing each to recover all or substantially all of their prudently incurred stranded costs which are pre-restructuring expenditures incurred, or commitments made for future expenditures, on behalf of customers with the expectation such expenditures would continue to be recoverable in the future through rates. All three companies have

recovered significant portions of their stranded costs through the issuance of rate reduction bonds (RRBs) and rate reduction certificates (RRCs) (securitization) and are recovering the costs of securitization through rates. As of December 31, 2004, CL&P had fully recovered all stranded costs except those being recovered through RRB-related charges, ongoing independent power producer costs, costs associated with the ongoing decommissioning of the Maine Yankee, Connecticut Yankee and Yankee Rowe nuclear units and annual decontamination and decommissioning costs payable under federal law.

All of NU's electric operating company customers are now able to choose their energy suppliers, with the electric companies furnishing "standard offer," "default" or "transition" service to those customers who do not choose a competitive supplier. Management recognizes that in other states electric companies have been negatively affected by the inability to recover supply costs on a timely basis. To date, regulators have allowed the NU companies recovery of such costs in full, and management believes that current statutes and regulatory policy in Connecticut, Massachusetts and New Hampshire will continue to permit timely recovery.

In accordance with amendments passed in 2003 to Connecticut's electric restructuring legislation, CL&P signed fixed-price contracts in 2003 and 2004 with four wholesale suppliers who together will serve all of CL&P's transitional standard offer (TSO) requirements in 2005. None of CL&P's suppliers for 2005 is affiliated with the company. CL&P is fully recovering all of the payments it is making to those suppliers and has financial guarantees from each supplier to mitigate CL&P from risk in the event any of the suppliers encounters financial difficulties. CL&P has filled a portion of its TSO requirements for 2006 and will initiate a new solicitation process in the future to procure generation supply for the unfilled portion of its TSO load obligation for that year. See "Connecticut Retail Rates."

After a competitive solicitation, WMECO signed supply agreements for standard offer service in October 2003 for the period January 1, 2004 through February 28, 2005 (the transition period in which standard offer service is to be available terminated on February 28, 2005). Select Energy was one of two winning bidders; the second was an unaffiliated supplier. The DTE approved the standard offer contract and approved rates which will allow WMECO to recover fully its standard offer service supply costs. In addition, in Massachusetts there is a second type of service supplied by electric distribution companies called default service. Default service is provided to those customers not on competitive supply that are not eligible for standard offer service. On March 1, 2005, these customers remaining on standard offer service were switched to default service. Under current state law, default service, which the DTE has determined for purposes of customer communications is to be referred to as "basic service," will continue indefinitely.

Pursuant to a DTE order issued in 2003, there are now two separate solicitations for default service. For larger customers, WMECO default service rates are set for a three-month period. For smaller customers, WMECO default service rates are set for a six-month period. Accordingly, default service has been solicited and rates approved for larger customers for the period January 1, 2005 through March 31, 2005. A single unaffiliated entity is the supplier. Default service has been solicited and rates have been approved for smaller customers for the period January 1, 2005 through June 30, 2005. Two unaffiliated entities will provide this service. For larger customers, WMECO has awarded default service for the period April 1, 2005 through June 30, 2005 to Select Energy. On December 6, 2004, the DTE opened an investigation seeking to determine if the manner in which default service is procured for smaller customers should be changed. It is not known when the DTE will issue an order in this proceeding.

PSNH provides transition energy service (TS) and default energy service (DS) to its retail customers from its generating plants, from power purchased under long-term contracts and from open market purchases. PSNH reconciles its cost and rate recovery in periodic TS/DS rate proceedings. See "New Hampshire Retail Rates."

Connecticut Retail Rates

CL&P – Rate Matters

Since retail competition began in Connecticut in 2000, most of CL&P's customers have continued to buy their power from CL&P at standard offer rates (2000-2003) and TSO rates (2004-2006). Only a small number of CL&P customers (approximately 21,000 out of nearly 1.2 million) have opted for a competitive retail supplier.

Pursuant to state law, CL&P filed a rate case on August 1, 2003. The DPUC issued a final decision in December, 2003, effective January 1, 2004, that authorized rate recovery of approximately $900 million over four years for its distribution capital program; approved incremental distribution rate increases totaling approximately $42.1 million between January 1, 2004 and December 31, 2007; applied $120 million of prior year generation service charge overcollections as credits against the authorized rate increases in the amount of $30 million per year; authorized a transmission rate increase of $28.4 million for 2004 with the understanding that CL&P could seek DPUC approval to reflect any future transmission-related revenue requirement increases in rates; and approved an ROE of 9.85 percent with earnings above that level to be shared 50/50 between customers and shareholders. These rates are included in CL&P's total TSO rates. On December 31, 2003, CL&P filed a petition for reconsideration (Petition) of the DPUC's final decision on the grounds that the final decision improperly (i) disallowed $15.7 million of CL&P's pension-related costs, (ii) concluded that the Connecticut statute of limitations does not apply to claims alleging that CL&P over-billed municipalities for streetlighting costs, and (iii) failed to implement additional

revenue requirement adjustments equal to approximately $5.3 million, $3.6 million, $4 million and $4 million in 2004 through 2007, respectively.

Also, pursuant to state law, on December 19, 2003, the DPUC set CL&P's TSO rates for January 1 through December 31, 2004 and confirmed that state law exempted FMCC charges, Energy Adjustment Clause (EAC) charges and certain other charges from the statutorily imposed rate cap. The Connecticut Office of Consumer Counsel (OCC) has appealed this decision to the Connecticut Superior Court. The OCC claims that the decision improperly implements an EAC charge under Connecticut law, fails to properly define and identify the fees that CL&P will be allowed to collect from customers, and improperly calculates base rates for purposes of determining the rate cap.

On August 4, 2004, the DPUC issued a decision on reconsideration allowing additional recovery for CL&P's pension related regulatory asset, incentive compensation, rental expense and income taxes, in the total amount of approximately $24 million (net present value), and placing a limitation on the company's liability for claims for streetlight account refunds. Oral argument on the OCC's appeal of this decision was held on March 11, 2005.

On November 24, 2004, the DPUC issued a final decision that identified which specific costs imposed on CL&P by the FERC or ISO-NE constitute FMCCs within the meaning of Connecticut Public Act 03-135, as amended, and established a semi-annual proceeding to reconcile CL&P's FMCC charges that are recovered through rates. The DPUC's decision also authorized CL&P to seek adjustments to its FMCC charges outside of a semi-annual reconciliation proceeding sooner in the event an adjustment is necessary to reflect changes necessitated by the procurement of additional power to serve CL&P's TSO load or if there is a material change in FMCC expenses. On February 1, 2005, CL&P filed for approval for a 1.6 percent increase to rates ($29.2 million) to collect additional FMCCs effective May 1, 2005. The increase is necessary to collect costs related to an additional reliability must run (RMR) contract related to two generating plants located in southwest Connecticut. The RMR contract has preliminary approval for billing from the FERC and is subject to a future review by the FERC for final approval.

On December 22, 2004, the DPUC issued a final decision setting CL&P's TSO rates for January 1 through December 31, 2005. The decision approved an increase of approximately 10.4 percent above the average rates in effect in January 2004. The increase was necessary to collect higher costs for TSO generation supply and higher FMCCs. One percentage point of the increase was necessary to implement the increase to CL&P's distribution rate previously approved for 2005. On February 3, 2005, the OCC filed an appeal with the Connecticut Superior Court challenging this decision. This appeal is identical to the appeal filed with the same court in February 2004 challenging the DPUC's December 2003 decision.

On August 4, 2004, the DPUC issued a decision concerning the reconciliation of two components of CL&P's retail rates, the competitive transition assessment (CTA) and the systems benefits charge (SBC), for calendar year 2003. The CTA recovers CL&P's DPUC-approved stranded costs from customers. The August 4 decision required CL&P to credit customers with the hypothetical profit CL&P would have realized from its purchase and sale of 250,000 megawatt hours (MWhs) of power from the Connecticut Resources Recovery Authority's (CRRA's) generating project in Hartford (the Market Price Cost Differential). The energy purchase agreement under which CL&P was purchasing this power from CRRA's Hartford generating project was rejected by a Bankruptcy Court in March 2003, and CL&P made no such purchases or sales in 2003. The decision nevertheless directed CL&P to credit the $2.7 million Market Price Cost Differential for 2003 to customers. In addition, the DPUC ordered CL&P to credit the Market Price Cost Differential for each year from 2004 through 2012 (the end date of the rejected power purchase agreement). CL&P subsequently appealed the August 4 decision. On December 1, 2004, based on a settlement CL&P reached with CRRA, the Connecticut Attorney General and DPUC's Prosecutorial Staff, the DPUC issued a decision in the same proceeding that rescinded this portion of its August 4, 2004 decision.

In the 2001 CTA and SBC reconciliation filing, and subsequently in a September 10, 2002 petition to reopen related proceedings, CL&P requested that a deferred intercompany tax liability associated with the intercompany sale of generation assets be excluded from the calculation of CTA revenue requirements. On September 10, 2003, the DPUC issued a final decision denying CL&P's request, and on October 24, 2003, CL&P appealed the DPUC's final decision to the Connecticut Superior Court. The appeal has been fully briefed and argued. A decision from the court is not expected to be issued until the second quarter of 2005. If CL&P's request is granted through these court proceedings, then there could be additional amounts due to CL&P from its customers. The 2004 impact of including the deferred intercompany liability in CTA revenue requirements has been a reduction of approximately $19.3 million in revenue.

In October 2002, CL&P filed a complaint at the FERC seeking interpretation of a FERC-filed interconnection agreement in which NRG agreed to pay CL&P's applicable retail rates for station service power (if procured from CL&P) and delivery of such power (whether procured from CL&P or a third party supplier). By order dated December 20, 2002, the FERC affirmed the language in its Order 888 concerning state jurisdiction over the delivery of power to end users, even in the absence of distribution facilities, and the state's authority to impose certain charges on end users, such as those associated with stranded cost recovery. CL&P subsequently made a demand upon NRG for payment of $13.3 million in station service charges through January 2003 and initiated a proceeding at the DPUC seeking a declaratory ruling that its DPUC approved rates were appropriately charged to NRG. Prior to a DPUC ruling, NRG filed a petition for relief under Chapter 11 of the U.S. Bankruptcy Code. On September 18, 2003, the Bankruptcy Court approved a stipulation

between CL&P and NRG to submit the station service dispute to arbitration. As part of the CL&P rate case decision dated December 17, 2003, the DPUC determined that CL&P had appropriately administered its station service rates. Subsequently, however, in unrelated proceedings, the FERC issued a series of orders with conflicting policy direction which call into question its December 20, 2003 NRG order. In July 2004, CL&P filed a request with the FERC for further clarification of this issue. Arbitration proceedings have been initiated by the parties, but no hearing dates have been scheduled. For further information relating to NRG-related litigation, see Item 3, "Legal Proceedings."

On February 1, 2005, CL&P filed an application with the DPUC to obtain approval to defer for future recovery in its retail transmission rate the increased transmission costs that CL&P is incurring as of February 1, 2005. If the DPUC does not approve the proposal to defer the increased transmission costs, CL&P's filing makes an alternative proposal to increase its retail transmission rate to recover an additional $7.6 million on an annual basis, effective February 1, 2005. As a result, CL&P's approved annual transmission revenue requirement would be $121.2 million. This increase would equal 0.031 cents per kWh, and would represent about a 0.2 percent increase in overall rates as of February 1, 2005, and an increase of about 6.7 percent to the transmission rate.

CL&P – Transmission Projects

CL&P has undertaken a substantial transmission construction program over the past several years. On August 19, 2004, a Connecticut Superior Court judge dismissed an appeal by the City of Norwalk contesting the permit granted to CL&P by the CSC to construct a 21-mile, 345 kV transmission project from Bethel, Connecticut to Norwalk, Connecticut. Based upon a recently completed estimate, the project is currently projected to cost between $300 million and $350 million. The project is expected to begin to alleviate identified reliability issues in southwest Connecticut and to help offset rising federally mandated and other costs for all of Connecticut. Work on the related substations has begun, and work on the transmission lines is expected to start in March 2005 after finalization of construction contracts with vendors and receipt of permits from the affected towns and the Connecticut Department of Transportation. Management estimates a project completion date of December 2006. At December 31, 2004, CL&P has capitalized $65 million associated with this project.

On October 9, 2003, CL&P and The United Illuminating Company (UI) filed for approval at the CSC for a separate 69-mile 345 kV transmission line from Middletown, Connecticut to Norwalk, Connecticut. Construction is expected to commence after the final route and configuration are determined by CSC. CL&P and UI initially estimated a cost of $620 million for the total project. In June 2004, after ISO-NE raised concerns over the amount of underground line that had been proposed, the CSC requested that a committee comprised of representatives of CL&P, UI and ISO-NE study various alternatives and reach a consensus on the proposed project configuration. The committee's report was filed on December 20, 2004 and recommended a maximum of 24 miles of underground line. On December 28, 2004 CL&P and UI filed updated cost estimates with the CSC which reflect changes needed to address technical issues introduced by the extensive amount of underground transmission being proposed and a two-year delay in the project in-service date from 2007 to 2009. The new estimates place the cost of the project between $840 million and $990 million. The variation in the cost range is due to unknown conditions that may be encountered during construction and a provision for other contingencies. Additional steps to lower magnetic fields along the overhead portion of the route proposed by the CSC would add between $70 million and $80 million to the estimated cost. The CSC concluded hearings on the proposal and the alternatives on February 17, 2005 and set a briefing schedule at that time. A ruling on the proposed project is expected by April 7, 2005. At December 31, 2004, CL&P has capitalized $18 million associated with this project. CL&P's share of this project is 80 percent and UI's share is 20 percent.

In September 2002, the CSC approved a plan to replace an undersea 13-mile electric transmission line between Norwalk, Connecticut and Northport - Long Island, New York. This project is estimated to cost in the range of $114 to $135 million, and CL&P and the Long Island Power Authority (LIPA) will each own approximately 50 percent of the line. CL&P has not yet signed a contract with a vendor to complete this work; therefore, the cost estimate could increase. The project has received CSC approval but still requires federal and New York state approvals. On October 1, 2004, consistent with a comprehensive settlement agreement reached on June 24, 2004, CL&P and LIPA jointly filed an implementation plan for the cable replacement with the Connecticut Department of Environmental Protection (CDEP). Construction activities are scheduled to begin in the fall of 2006. Management expects the cable to be in service by the middle of 2008. At December 31, 2004, CL&P has capitalized $7 million related to this project.

In May 2004, CL&P applied to the CSC to construct two nine-mile 115 kV underground transmission lines between Norwalk, Connecticut and Stamford, Connecticut. The project is expected to cost approximately $120 million and will help meet the growing electric demands in the area. Management expects the lines to be in service by 2008. At December 31, 2004, CL&P has capitalized $3 million related to this project.

During 2004, NU placed in service $123 million of electric transmission projects. These projects included CL&P's $38 million upgrade of a transmission substation in Stamford, Connecticut that allows additional imports into southwest Connecticut.

For further information on NU's transmission construction program, see "Construction and Capital Improvement Program."

Yankee Gas

In 2002, the DPUC approved an Infrastructure Expansion Rate Mechanism (IERM) to enable Yankee Gas to add some significant expansion projects to rate base in a limited proceeding, rather than requiring the filing of a full rate case. On April 24, 2003, the Connecticut OCC appealed the DPUC's decision, challenging the legality of the IERM. Yankee Gas filed its 2003-2004 IERM application with the DPUC on October 1, 2003. On April 27, 2004, Yankee Gas and the OCC reached a settlement concerning all of the pending IERM-related claims between the parties and eliminating the IERM as a rate making mechanism and providing for recovery of approximately $32 million in capital expenditures. The settlement was approved by the DPUC on August 4, 2004.

On September 3, 2004, in connection with Yankee Gas' filing to construct and operate a 1.2 billion cubic foot liquefied natural gas (LNG) facility, the DPUC concluded that there was a need for the LNG capacity and that construction of the facility was a reasonable approach to satisfying that need in light of the facility's reliability and operational benefits. In that decision, the DPUC also concluded that Yankee Gas' actions incurred in pursuit of the proposed LNG facility had been prudent and authorized Yankee Gas to defer these costs for future recovery. The DPUC also granted a rebuttable presumption of prudence for the facility's contract construction costs, associated construction phase property taxes and AFUDC expenditures in a future rate case in which the facility will be placed into rate base. Construction of the facility has begun and it is expected to be in service by the 2007-2008 heating season at an estimated cost of $108 million.

On December 8, 2004, the DPUC approved in full a rate case settlement between Yankee Gas, the OCC and the Prosecutorial Division of the DPUC. The decision allowed a rate increase for Yankee Gas as of January 1, 2005 in the amount of $14 million (4.1 percent to total costs, 9.4 percent to distribution portion of rates), with an ROE of 9.9 percent. Yankee Gas was also allowed lower depreciation expense related to costs of removal due to adequate reserve levels, which will lower Yankee Gas' expenses by $5.7 million annually. Under the settlement agreement, Yankee Gas agreed not to file a new application for a rate increase that would become effective prior to the earlier of (i) the in-service date of the LNG facility; or (ii) July 1, 2007. However, Yankee Gas reserved the right to request rate relief that would become effective prior to July 1, 2007 if it incurs or will incur unanticipated substantial and material cost increases as a result of changes in law, administrative requirements or accounting standards, or due to a *force majeure* event.

Massachusetts Retail Rates

Massachusetts enacted comprehensive electric utility industry restructuring in November 1997. That legislation required each electric company to submit a restructuring plan and to reduce its rates by 15 percent adjusted for inflation by September 1999. The 15 percent rate reduction is a rate cap for standard offer service customers that extends until February 28, 2005, the end of the restructuring transition period.

On December 29, 2004, the DTE approved a rate settlement entered into by WMECO, the Massachusetts Attorney General, the Associated Industries of Massachusetts and the Low-Income Energy Affordability Network. The approved rate settlement allows WMECO to increase the distribution component of its rates to collect an additional $6.0 million in calendar 2005 and an additional $3.0 million above 2005 distribution rates in calendar 2006. Under the rate settlement, WMECO will also reduce its transition charge to approximately five mills, or $13 million, during calendar 2005 and 2006, although the charge will be no lower, in any case, than necessary to service WMECO's outstanding RRBs.

Other provisions of the rate settlement provide : (i) that WMECO will not seek any further distribution rate increase that would become effective before January 1, 2007 other than if its ROE drops below 7.0 percent; (ii) for an earnings sharing mechanism should WMECO's ROE exceed 11 percent or drop below seven percent, providing a 50-50 sharing of excess earnings or future recovery of deficit earnings from customers and shareholders after DTE review; (iii) that WMECO will spend not less than $24 million in 2005 and 2006 on capital expenditures related to reliability; (iv) that WMECO will expand a program for low-income customers having difficulty in paying their bills, with the costs of such expansion in excess of the benefits to be recovered in WMECO's next general distribution rate case; and (v) that WMECO will send a reliability "report card" to its customers each year and work with the Massachusetts Attorney General on service quality issues.

New Hampshire Retail Rates

On January 1, 2004, PSNH acquired the franchise and electric system of Connecticut Valley Electric Company, Inc. (CVEC), a subsidiary of Central Vermont Public Service Corporation (CVPS) that serves approximately 11,000 customers in western New Hampshire. PSNH paid CVEC approximately $9 million for its assets and an additional $21 million for intangibles related to termination of a wholesale power contract between CVPS and CVEC. Upon closing, customers of CVEC became customers of PSNH. PSNH is recovering the $21 million payment with a return as a Part 3 stranded cost as defined in the "Agreement to Settle PSNH Restructuring" (Restructuring Settlement). Part 3 stranded costs are non-securitized regulatory assets which must be recovered by a recovery end date determined in accordance with the April 2000 Restructuring Settlement or be written off.

Under the terms of the Restructuring Agreement, PSNH provides both DS and TS to its customers, and DS/TS are priced at the same rate. On February 1, 2005, PSNH adjusted the costs it charges for generation services for the period February 1, 2005 through January 31, 2006. PSNH increased the DS/TS rates to 6.49 cents per kWh from 5.79 cents per kWh for all retail customers. The increase in the DS/TS rates allows PSNH to recover all actual and prudent costs, including the 11 percent ROE PSNH has previously been allowed on its net generation assets. In its January 28, 2005 order approving the February 2005 DS/TS rates, the NHPUC allowed the 11 percent ROE on an interim basis but deferred a decision on whether it was appropriate to continue to allow PSNH an 11 percent ROE in calculating DS/TS costs. The NHPUC has ordered a supplemental phase of this proceeding that will lead to a NHPUC decision on PSNH's appropriate ROE on generation investments by June 1, 2005. The NHPUC's January 2005 rate order allows for a midyear correction in the DS/TS rate. While management is unable to predict the outcome of the ROE docket, it expects that any material changes in the generation ROE would be implemented prospectively as part of the midyear correction in DS/TS rates that would be effective August 1, 2005.

PSNH's delivery rates were fixed by the Restructuring Settlement until February 1, 2004. Pursuant to the Restructuring Settlement and New Hampshire statute, PSNH filed a delivery service rate case on December 29, 2003. On September 2, 2004, the NHPUC approved a settlement providing for a $3.5 million increase in delivery service revenues on October 1, 2004 and an additional increase of $10 million on June 1, 2005, for a total rate increase of $13.5 million.

In August 2003, PSNH sought the approval of the NHPUC to modify one of its older 50 MW coal-fired generating stations, Unit 5 at Schiller Station in Portsmouth (Northern Wood Power Project), to a technologically advanced fluidized bed boiler capable of burning wood, with the plan to burn locally sourced low-grade wood fuel. This project would qualify Schiller Unit 5 to receive revenues from the sale of renewable energy certificates necessary to fulfill renewable portfolio standard requirements in Connecticut and Massachusetts. In May 2004, the NHPUC approved the Northern Wood Power Project and a risk/reward cost-recovery mechanism jointly offered by PSNH, the New Hampshire Governor's Office of Energy and Planning, the New Hampshire Office of Consumer Advocate, and the New Hampshire Timberland Owners' Association. Construction of the facility has commenced. For information on the appeal of the NHPUC's orders pending with the New Hampshire Supreme Court, see Item 3, "Legal Proceedings."

COMPETITIVE SYSTEM BUSINESSES

NU is engaged in a variety of competitive businesses, primarily the retail and wholesale marketing of electricity and natural gas in the northeastern United States and the provision of energy related services to large government, industrial, commercial and institutional facilities.

NUEI is a wholly-owned subsidiary of NU and acts as the holding company for certain of NU's competitive energy subsidiaries. These subsidiaries include SESI, a provider of energy management, demand-side management and related consulting services for commercial, industrial and institutional customers and electric utility companies; NGC, a corporation that acquires and manages generation facilities; NGS, a corporation that maintains and services fossil and hydroelectric facilities and provides high-voltage electrical contracting services, and Select Energy, a corporation engaged in the marketing, transportation, storage and sale of energy commodities, at wholesale and retail, in designated geographical areas. The generation operations of HWP are also included in the results of NUEI. NUEI and its integrated competitive energy business affiliates had aggregate revenues of approximately $2.9 billion in 2004 as compared to approximately $2.6 billion in 2003 and had losses of $15.1 million in 2004, as compared to a loss of approximately $3.4 million in 2003.

NGC is the competitive generating subsidiary of NU and a major provider of pumped storage and conventional hydroelectric power in the northeastern United States. NGC sells all its generation output to Select Energy, which in turn markets it to customers. Select Energy also buys and manages the entire generation output of HWP, which consists of approximately 147 megawatts (MW) of coal-fired generation at the Mt. Tom station in Holyoke, Massachusetts under an evergreen contract. NGC's assets and Mt. Tom perform functions that are critical to NUEI's wholesale and retail businesses by providing Select Energy with access to electric generation within New England and thus reducing its exposure to energy price fluctuations.

On March 9, 2005, NU announced that it had completed its previously announced comprehensive review of its competitive energy businesses and that it has decided that NUEI will exit the wholesale marketing business, which it conducts through its subsidiary Select Energy, and will explore ways to divest its competitive energy services businesses. NU concluded that the wholesale merchant energy sector in the power pools between Maine and Maryland is becoming increasingly competitive and that NUEI's wholesale marketing business will be unable to attain the profit margins necessary to generate acceptable returns and cash flows. As a result, NUEI will explore a number of alternatives for exiting the wholesale marketing business, including selling the wholesale marketing franchise, selling existing contracts, restructuring longer term contracts, and allowing shorter term contracts to expire without being renewed. Select Energy will only bid on new full requirements wholesale contracts to improve the value of its book of business by reducing existing electric positions. NU will retain its 1,443 megawatts of competitive generating assets because it expects that their value could increase significantly in the coming years. It will also retain NGS, which principally operates these plants.

Retail and Wholesale Marketing

NUEI, through Select Energy, sells multiple energy products including electricity and natural gas to wholesale and retail customers in the northeastern United States. Select Energy procures and delivers energy and capacity required to serve its electric and gas customers. In order to support and complement its growing wholesale and retail business, Select Energy contracted in December of 1999 with NGC to purchase and market all of NGC's 1,296 MW for a six-year period, extended through December 2007. In addition, during 2004 Select Energy purchased approximately 147 MW of coal generating plant output from its affiliate, HWP, and more than 4,000 MW of electrical supply from various New England generating facilities on a long-term basis to meet its New England load obligations. Select Energy utilizes generation failure insurance, options and energy futures to hedge its supply requirements. NUEI also offers energy management consulting and construction services through its affiliate, SESI, discussed more fully below.

In 2004, Select Energy reported revenues of $2.6 billion and had retail and wholesale marketing sales of approximately 41,000 gigawatt-hours (GWh) of electricity and 57 billion cubic feet (BcF) of natural gas to approximately 30,000 customers. During 2003, Select Energy reported revenues of $2.3 billion and had retail and wholesale marketing sales of approximately 40,000 GWh of electricity and 46 BcF of natural gas to approximately 26,000 customers.

In general, over the last few years, the market for energy products has become shorter term in nature with less liquidity and participants are sometimes unable to meet Select Energy's credit standards without providing cash or LOC support. In addition, wholesale power competition increased significantly in New England over the last six months of 2004. Select Energy's business has been adversely affected by these factors and they contributed to NU's decision to exit the wholesale competitive energy business.

Changes are occurring in the administration of transmission systems in territories in which Select Energy does business. RTOs are being proposed and approved and other changes in market design are occurring within transmission regions. The impact of SMD on the wholesale marketing business has been significant. As the market continues to evolve, there could be additional challenges or opportunities that management cannot determine at this time. For more information on the proposed changes, see "Regulated Electric Operations- Transmission Access and FERC Regulatory Charges" and "Regulated Electric Operations-Connecticut Retail Rates."

Retail Marketing

Select Energy is licensed to provide retail electric supply in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, Ohio, Pennsylvania, Virginia, the District of Columbia, New York and Rhode Island. Within these states, Select Energy is currently registered with 38 electric distribution companies and 54 gas distribution companies to provide retail services.

Select Energy's retail marketing business had a $6.7 million improvement in performance during 2004, with net income of $4.9 million versus a loss of $1.8 million in 2003. The stronger performance is attributed to increased electric and gas sales, which increased from approximately $660 million in 2003 to approximately $850 million in 2004. Select Energy expects its retail marketing business to repeat its success and to be similarly profitable in 2005, when it projects approximately $1 billion in sales. This projection assumes that Select Energy will be successful in securing and managing a significant amount of new business at acceptable margins.

As of December 31, 2004, Select Energy had contracts with retail electric customers in states throughout the Northeast which produced revenues of approximately $560 million, from over 1,800 MW of peak load at approximately 18,000 locations, including predominately commercial, industrial, institutional and governmental accounts. As over 700 MW of this load is in New England, Select Energy is among the largest competitive retail suppliers of electricity in New England as measured by MW load. During 2004, retail load totaled nearly 10 million MWh. No single retail electric customer accounted for more than ten percent of Select Energy's retail revenues.

During 2004, Select Energy's competitive natural gas business, which is primarily retail in nature, produced revenues of approximately $410 million, an increase from 2003 revenues of approximately $129 million. This increase relates to both higher gas prices and higher gas volumes. As of December 31, 2004, Select Energy provided over 39 BcF of natural gas to approximately 12,000 retail gas customers, primarily located in Connecticut, Massachusetts, New York and Pennsylvania. These contracts generally have one-year terms and include primarily commercial, institutional, industrial and governmental accounts. No single retail gas customer accounted for more than ten percent of Select Energy's retail gas revenues.

Wholesale Marketing

In 2004, Select Energy supplied more than 5,800 MW of standard offer and default service load in the Northeast, making it one of the largest providers of standard offer service in that region. Revenues from these services comprised in the aggregate approximately 54 percent of Select Energy's 2004 revenues.

During 2004, the wholesale marketing business lost $17 million, primarily due to a $48.3 million mark-to-market loss associated with certain wholesale natural gas positions established to economically hedge electricity purchased in anticipation of winning certain

levels of wholesale electric load in New England. In 2003, that business lost $3.7 million due to a $35.6 million write-off relating to a contract settlement between Select Energy and CL&P.

In 2004, Select Energy served approximately 1,800 MW of TSO load of its affiliate, CL&P. Total Select Energy revenues from serving CL&P's standard offer load, TSO load and for other transactions with CL&P represented $611.3 million or 21 percent of NUEI's total revenues for the year ended December 31, 2004. In addition to its contract with CL&P, Select Energy revenues related to contracts with NSTAR companies represented $300.2 million or 11 percent of NUEI's total revenues for the year ended December 31, 2004. Select Energy also provides basic generation service in the New Jersey and Maryland market. Select Energy revenues related to these contracts represented $334.2 million or 12 percent of NUEI's total revenues for the year ended December 31, 2004. No other individual customer represented in excess of 10 percent of NUEI's revenues for the year ended December 31, 2004.

On November 15, 2004, NU announced that Select Energy had been unsuccessful in its bid to supply a portion of the load for CL&P in 2005 and beyond. As a result of the failure to secure any of the CL&P load and due to diminished levels of success in other New England bids, a comprehensive review of NUEI's businesses, including that of Select Energy, was undertaken, which concluded on March 9, 2005 that Select Energy should exit the wholesale marketing business See "Risk Factors" and "Competitive System Businesses."

Trading activities are limited primarily to price discovery, risk management and deal execution for merchant energy activities.

Electric Generation

NGC, NU's competitive electric generating affiliate, owns and operates a portfolio of approximately 1,296 MW of hydroelectric and pumped storage generating assets in Connecticut and Massachusetts. NGC's portfolio consists of seven hydro facilities along the Housatonic River System, the three facilities comprising the Eastern Connecticut System, including one gas turbine, all located in Connecticut, and the Northfield Mountain pumped storage station and the Cabot and Turners Falls No. 1 hydroelectric stations located in Massachusetts. NGC sells all of its energy and capacity to its affiliate, Select Energy. Select Energy's performance under its contract with NGC is guaranteed by NU through 2007. Select Energy also buys and manages the entire generation output of approximately 147 MW from HWP's Mt. Tom coal-fired generating plant under a contract renewable on an annual basis. Select Energy uses the NGC and Mt. Tom generation to furnish a portion of the resources it uses to meet supply commitments to its marketing customers. For further information relating to NU's electric generating plants, see Item 2, "Properties – Electric Generating Plants."

NGC's contract with Select Energy extends through December 2007. During the remaining term, 82 percent of NGC's revenues from this contract (including all of the revenues from Northfield Mountain) are in the form of predetermined, fixed monthly payments based on the capacity of specified facilities. The remaining 18 percent of the revenues are in the form of monthly payments at predetermined rates per unit of actual energy output. NGC expects to derive approximately 77 percent of its revenues from Northfield Mountain. This contract provides NGC with a stable stream of revenues at prices that are currently higher than average wholesale electricity prices in the markets served by NGC's facilities.

In March 2004, ISO-NE filed a proposal at the FERC to implement LICAP requirements. LICAP is an administratively determined electric generation capacity pricing mechanism intended to provide a revenue stream sufficient to maintain existing generation assets, and encourage the construction of new generation assets at levels sufficient to serve peak load, plus a reserve margin and a cushion. In June 2004, the FERC ordered the creation of five LICAP zones and accepted ISO-NE's demand curve methodology. The FERC ordered LICAP to be implemented by January 1, 2006 and set certain issues pertaining to the demand curve for hearings. Hearings began in the end of February 2005. In August 2004, ISO-NE revised its proposal and several intervenors, including FERC staff and various state regulators, have put forth alternative demand curve proposals.

Depending on the pricing curves that are ultimately implemented, LICAP could produce significant benefits for generation assets either owned or leased by NU's competitive energy businesses. Those benefits would likely be greater per kWh rates for generation located in Connecticut than generation assets located in Massachusetts because the capacity margin is much lower in Connecticut than it is in central and western Massachusetts. As a result, LICAP values are likely to be higher in Connecticut. NU's competitive energy businesses own or lease approximately 300 megawatts in Connecticut and approximately 1,300 megawatts in western Massachusetts. A FERC decision is anticipated in the fall of 2005.

NU concluded a comprehensive review of its competitive energy businesses on March 9, 2005, and announced that it will retain its competitive generation. See "Risk Factors" and "Competitive System Businesses."

Competitive Energy Subsidiaries' Market And Other Risks

The decision to exit the wholesale marketing business and limit wholesale marketing activities will change the risk profile of NUEI in 2005. Subsequent to the disposition of the wholesale marketing business, NUEI will continue to be exposed to certain market risks; however, management believes that those risks will be reduced. The merchant energy business segment will be comprised of generation assets and the retail marketing segment, which will enter into contracts of varying lengths of time to buy and sell energy commodities, including electricity, natural gas, and oil to retail customers. Market risk represents the loss that may affect the merchant energy business segment's financial results, primarily Select Energy, due to adverse changes in commodity market prices.

Risk management within Select Energy has been organized to address the market, credit and operational exposures arising from its wholesale marketing business (which includes limited energy trading for market and price discovery purposes) and its retail marketing activities. A significant portion of the retail and wholesale marketing business is providing full requirements service to customers, primarily regulated distribution companies for the wholesale business and commercial, industrial, institutional and governmental accounts for the retail business. The "full requirements" obligation commits these companies to supply the total energy requirement for the customers' load at all times. An important component of Select Energy's risk management strategy is to manage the volume and price risks of its full requirements contracts. These risks include unexpected fluctuations in both supply and demand due to numerous factors which are not within its control, such as weather, plant availability, exposure to transmission congestion costs and price volatility.

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

To mitigate the risk of electricity price decreases on the fixed-price electricity that was purchased, Select Energy in June 2004 began selling wholesale natural gas contracts for 2005 and 2006. The intended result of this risk mitigation strategy was that the value of the fixed-price electricity purchase contracts would be offset in part by increases in the value of the gas contracts, and vice versa. Select Energy intended to purchase natural gas when quantities and prices of electricity are secured by full requirements contracts or sales contracts with load-serving entities. Natural gas was sold in this risk mitigation strategy due to the high liquidity of the natural gas market compared to the low liquidity of electricity in the Northeast. Select Energy's failure to win large wholesale loads at competitive bidding in the fall of 2004 at previously experienced levels, combined with adverse price movements in both gas and electric markets, contributed significantly to wholesale marketing losses in 2004.

In serving its marketing customers, Select Energy utilizes derivative financial and commodity instruments, including options and forward contracts, to manage the risk of fluctuating market prices. At December 31, 2004, Select Energy had hedging derivative assets of $4.5 million, as compared to hedging derivative assets of $56 million at December 31, 2003. Generally, such derivatives impact earnings over the life of the contracts which they hedge, but in certain cases the impact is accelerated and affects earnings immediately.

Select Energy's trading portfolio had a net positive $29.6 million fair value at December 31, 2004, as compared to a net positive $32.5 million fair value at December 31, 2003. Approximately 98 percent of the $29.6 million was priced from external sources and only a nominal amount was based on exchange quotes. Of the $29.6 million of net fair value in the trading portfolio at December 31, 2004, $3.5 million will mature in 2005, $13.6 million in 2006-2008 and $12.5 million after 2008.

Accordingly, there is a risk that the trading portfolio will not be realized in the amount recorded. Realization of cash will depend upon a number of factors over which Select Energy has limited or no control, including the accuracy of its valuation methodologies, the volatility of commodity prices, changes in market design and settlement mechanisms, the outcome of future transactions, the performance of counterparties, the breadth and depth of the trading market and other factors.

In addition, the application of derivative accounting principles is complex and requires management judgment in identification of derivatives and embedded derivatives, election and designation of the "normal purchases and sales" exceptions identifying hedge relationships and assessing hedge effectiveness, determining the fair value of derivatives and measuring hedge ineffectiveness. All of these judgments, depending upon their timing and effect, can have a significant impact on the competitive subsidiaries' performance and, ultimately, NU's consolidated net income.

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

As a means to monitor and control compliance with these policies and procedures, NU has a Risk Oversight Committee (ROC) to monitor competitive energy risk management processes independently from the businesses that create and manage these risks. The ROC

ensures that the policies pertaining to these risks are followed and periodically adjusts the metrics used in measuring and controlling portfolio risk while also reviewing the methodologies employed by management to discern portfolio values.

Energy Management Services

NUEI has two affiliated companies in the energy related services business: NGS and SESI, which accounted for approximately $275 million of non–affiliate revenue in 2004.

NGS manages, operates, maintains and supports electric power generating equipment, facilities and associated transmission and distribution equipment and provides turnkey management and operation services to owners of electric generation facilities. NGC and HWP have contracted with NGS to operate and maintain all of their generating plants.

Through its wholly-owned subsidiaries, E.S. Boulos Company (Boulos) and Woods Electrical Co., Inc. (Woods Electrical), NGS provides electrical construction and contracting services. These services focus on high and medium voltage installations and upgrades and substation and switchyard construction. Woods Network, a subsidiary of NUEI, is a network products and services company.

During 2004, NGS's revenues were approximately $113 million. Forty-three percent of NGS's revenues in 2004 were derived from contracts with its affiliates, most of which related to NGS's operation of NUEI's competitive generation assets.

SESI was acquired in 1990 and provides energy efficiency, design and construction solutions to government, institutional and commercial facilities. In delivering its services, SESI focuses on reducing its customers' energy costs, improving the efficiency and reliability of their energy-consuming equipment and conserving energy and other resources. SESI also designs, builds and maintains central energy plants producing power, heating and cooling for their hosts. SESI's engineering and construction management services have been directed primarily to markets in the eastern United States. SESI's subsidiary, Select Energy Contracting, Inc. (SECI), provides service contracts and mechanical and electrical contracting, primarily directed to energy systems in commercial markets. In 2004, SESI had revenues of approximately $192 million. In 2005, SESI's revenues are anticipated to decrease by 17 percent based on a new business model that focuses on more profitable projects rather than growth in revenue.

As a result of the comprehensive review of its competitive energy businesses, NU announced on March 9, 2005 that it will explore ways to divest its energy services businesses in a manner that maximizes their value, but intends to retain NGS and its competitive generation assets. See "Risk Factors" and "Competitive System Businesses."

Telecommunications

Mode 1 is a wholly-owned exempt telecommunications subsidiary of NUEI. Mode 1 is a licensed competitive local exchange carrier authorized to provide local phone service within the state of Connecticut.

At December 31, 2004, NU's net investment in Mode 1 was approximately $13 million, most of which was used to fund Mode 1's investment in NEON Communications, Inc. (NEON). NEON is a wholesale provider of high bandwidth, advanced optical networking solutions and services to communications carriers on intercity, regional and metro networks in the twelve-state Northeast and mid-Atlantic markets, utilizing a portion of the NU system companies' and other electric utilities' transmission and distribution facilities. During 2004, Mode 1 owned approximately 9.3 percent of NEON on a fully diluted basis. NEON merged with Globix Communications, Inc., a website hosting company, on March 8, 2005. Mode 1's share in the combined companies is approximately 5.3 percent.

REGULATED GAS OPERATIONS

Yankee is the holding company of Yankee Gas and its two active non-utility subsidiaries, NorConn, which holds certain minor properties and facilities of Yankee and its subsidiaries, and Yankee Energy Financial Services Company, which provides Yankee Gas customers with financing for energy equipment installations.

Yankee Gas operates the largest natural gas distribution system in Connecticut as measured by number of customers and size of service territory. Total throughput (sales and transportation) for 2004 was 47.3 billion cubic feet. In 2004, total gas operating revenues of $408 million were comprised of the following: 49 percent residential; 28 percent commercial; 20 percent industrial; and the remaining 3 percent other. Yankee Gas provides firm gas sales service to customers who require a continuous gas supply throughout the year, such as residential customers who rely on gas for their heating, hot water and cooking needs. Yankee Gas also provides interruptible gas sales service to certain commercial and industrial customers that have the capability to switch from natural gas to an alternative fuel on short notice. Yankee Gas can interrupt service to these customers during peak demand periods. Yankee Gas offers firm and interruptible transportation services to customers who purchase gas from sources other than Yankee Gas. In addition, Yankee Gas performs gas sales, gas exchanges and capacity releases to marketers to reduce its overall gas expense.

Although Yankee Gas is not subject to the FERC's jurisdiction, the FERC does have limited oversight over certain intrastate gas transportation that Yankee Gas provides. In addition, it regulates the interstate pipelines serving Yankee Gas' service territory. Yankee Gas, therefore, is directly and substantially affected by the FERC's policies and actions. Accordingly, Yankee Gas closely follows and, when appropriate, participates in proceedings before the FERC.

Yankee Gas is subject to regulation by the DPUC, which, among other things, has jurisdiction over rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service, management efficiency and construction and operation of distribution, production and storage facilities. For information relating to Yankee Gas DPUC proceedings, see "Regulated Electric Operations - Connecticut Retail Rates."

For information on the proposed expansion of Yankee Gas' natural gas delivery system in Connecticut, see "Construction and Capital Improvement Program."

FINANCING PROGRAM

2004 Financings

On January 30, 2004, Yankee Gas issued $75 million of first mortgage bonds (the Series G Bonds) with a coupon of 4.80 percent and a maturity of January 1, 2014. The proceeds of the transaction were used to refinance an increase in Yankee Gas' short-term debt to fund its capital needs.

On July 7, 2004, CL&P entered into multiple agreements to renew and extend its $100 million accounts receivable sale program. As part of the agreement, the bank commitment was extended for an additional 364 days through July 6, 2005, and the termination date of the facility was extended to July 3, 2007.

On July 22, 2004, PSNH issued $50 million of first mortgage bonds (the Series L Bonds) with a fixed coupon rate of 5.25 percent and a maturity of July 15, 2014. The proceeds of this issuance were used to refinance short-term debt and to fund PSNH's capital needs.

On September 17, 2004, CL&P issued $150 million of first mortgage bonds (the Series A Bonds) with a fixed coupon of 4.80 percent and a maturity of September 15, 2014. CL&P also issued $130 million of first mortgage bonds (the Series B Bonds) with a fixed coupon of 5.75 percent and a maturity of September 15, 2034. The proceeds of both issuances were used to refinance a portion of the company's short-term debt, as well as the redemption of the company's $59 million 1994 Series C bonds.

On September 23, 2004, WMECO issued $50 million in senior unsecured notes (the Series B Notes) with a coupon of 5.90 percent and a maturity of September 15, 2034. WMECO used the proceeds of the issuance to fund a trust established to match WMECO's obligations to Dominion Resources, Inc. for its liability to the U.S. Department of Energy for pre-1983 Millstone spent nuclear fuel.

On November 8, 2004, CL&P, WMECO, PSNH and Yankee Gas entered into a new unsecured five-year revolving credit facility for $400 million, replacing a 364-day $300 million facility that expired on November 8, 2004, under which they will be able to borrow on a short-term basis and, subject to certain conditions, on a long-term basis. CL&P may draw up to $200 million, and WMECO, PSNH and Yankee Gas may draw up to $100 million each, subject to the $400 million maximum for the entire facility. Unless extended, the facility will expire on November 6, 2009.

On November 8, 2004, NU entered into a new unsecured five-year revolving credit facility for $500 million, replacing a 364-day $350 million facility that expired on November 8, 2004, under which it will be able to borrow on a short-term basis and, subject to certain conditions, on a long-term basis. The new facility provides a total commitment of $500 million with a $350 million sub-limit for letters of credit. Unless extended, the credit facility will expire on November 6, 2009.

On November 15, 2004, Yankee Gas issued $50 million of first mortgage bonds (the Series H Bonds) with a fixed coupon of 5.26 percent and a maturity of November 1, 2019. The proceeds of this issuance were used primarily to pay back short-term debt incurred to redeem the company's Series A, Tranche E and Series C first mortgage bonds.

SESI engaged in various forms of off-balance sheet financing in 2004 associated with its demand side management business.

NU paid common dividends totaling $80.2 million in 2004, compared to $73.1 million paid in 2003, reflecting increases in the quarterly dividend rate that were effective September 30, 2003 and September 30, 2004.

Total NU system debt, including short-term debt, capitalized lease obligations and prior spent nuclear fuel liabilities, but not including RRCs and RRBs, was $3.1 billion as of December 31, 2004, compared with $2.7 billion as of December 31, 2003. The increase was primarily due to new debt issuances by CL&P, PSNH, WMECO and Yankee Gas.

For more information regarding NU system financing, see "Notes to Consolidated Financial Statements" in NU's financial statements, the footnotes related to long-term debt, short-term debt, leases and the sale of accounts receivables, as applicable, in the notes to NU's, CL&P's, PSNH's, and WMECO's financial statements and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

2005 Financing Requirements

The NU system's aggregate capital requirements for 2005 are approximately as follows:

	CL&P	PSNH	WMECO	Yankee Gas	Other	NU System
			(Millions)			
Construction	$ 420	$ 150	$ 40	$ 70	$ 60	$ 740
Maturities	0	0	0	20	0	20
Cash Sinking Funds*	0	0	0	0	71	71
Total	$ 420	$ 150	$ 40	$ 90	$ 131	$ 831

* CL&P, WMECO and PSNH have sinking funds associated with RRCs and RRBs that are not included in the capital requirements subtotal. All interest and principal payments for these bonds are collected through a non-bypassable charge assessed to customers and do not represent additional capital requirements.

For further information on the NU system's 2005 financing requirements, see "Notes to Consolidated Financial Statements " in NU's financial statements, "Long-Term Debt" in the notes to CL&P's, PSNH's and WMECO's financial statements and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

2005 Financing Plans

CL&P plans to issue up to $200 million of debt, primarily to finance its distribution and transmission businesses and for general corporate purposes. See –"Construction and Capital Improvement Program."

PSNH plans to issue up to $50 million of debt to refinance short-term debt and for general corporate purposes.

WMECO plans to issue up to $50 million of debt to refinance portions of its existing short-term debt and for general corporate purposes.

Yankee Gas plans to issue up to $50 million of debt to refinance maturing long-term debt, to finance its capital expenditures, including for the construction of its LNG facility, and for general corporate purposes. See "Construction and Capital Improvement Program."

Financing Limitations

Many of the NU system companies' charters and borrowing facilities contain financial limitations that must be satisfied before borrowings can be made and for outstanding borrowings to remain outstanding. In addition, the NU system companies are subject to certain federal and state orders and policies which limit their financial activities.

Financial Covenants in Short-Term Debt Credit Facility

Under their current revolving credit facility agreement, CL&P, WMECO, PSNH and Yankee Gas are allowed to maintain a ratio of debt to total capitalization (leverage ratio) of no more than 65 percent. At December 31, 2004, CL&P's, WMECO's, PSNH's, and Yankee Gas' leverage ratios were 51 percent, 55 percent, 55 percent and 37 percent, respectively. This agreement also requires CL&P, WMECO and PSNH to maintain 12-month earnings before interest and taxes to interest expense ratio (interest coverage ratio) of at least 2.00 to 1.00 and requires Yankee Gas to maintain an interest coverage ratio of at least 1.75 to 1.00. At December 31, 2004, CL&P's, WMECO's, PSNH's and Yankee Gas' interest coverage ratios were 3.88 to 1, 3.63 to 1, 4.20 to 1 and 2.03 to 1, respectively. These ratios do not include RRBs and RRCs and the leverage ratio for Yankee Gas does not exclude goodwill from capitalization.

NU is allowed, under its current revolving short-term credit agreement facility, to maintain a debt to total capitalization (leverage ratio) of no more than 65 percent. At December 31, 2004, NU's leverage ratio was 57 percent. In addition, NU is required to maintain a 12-month consolidated interest coverage ratio of at least 2.00 to 1.00. At December 31, 2004, NU's consolidated interest coverage ratio was 2.12 to 1.00. These ratios do not include RRBs and RRCs.

Short-Term Debt Limits

The amount of short-term debt that may be incurred by NU, CL&P, WMECO, Yankee, Yankee Gas and HWP is subject to periodic approval by the SEC under the Public Utility Holding Company Act of 1935 (1935 Act). On June 30, 2004, the SEC issued an order extending these companies' short-term debt authority and authority to participate in the Northeast Utilities System Money Pool (Money Pool) through June 30, 2007. The order also authorized the participation of the competitive subsidiaries in the Money Pool through June 30, 2007, but did not limit their borrowings from the Money Pool. NU, Yankee, Woods Network, NGC and Mode 1 may lend to, but are not authorized to borrow from, the Money Pool. The following table shows the amount of short-term borrowings authorized for each company, as the case may be, as of December 31, 2004, and the amounts of outstanding short-term debt of those companies at the end of 2004 and as of March 1, 2005 (in millions):

		Outstanding Short-Term Debt (1)	
	Maximum Authorized Short-Term Debt	December 31, 2004	March 1, 2005
NU	$ 450	$ 0	$ 0
CL&P	450	105.0	207.4
PSNH (2)	100	33.9	41.5
WMECO (3)	200	40.9	49.5
Yankee Gas	150	59.6	45.0
Yankee Energy System	50	0	0
HWP	10	7.1	6.0
Other (4)	N/A	143.9	169.8
Total		$ 390.4	$ 519.2

(1) These columns include borrowings of various NU system companies from NU, other NU system companies and unaffiliated lenders. Total NU system short-term indebtedness to unaffiliated lenders was $180 million at December 31, 2004 and $301 million at March 1, 2005.

(2) Under applicable NHPUC regulations, PSNH can incur short-term debt up to ten percent of fixed net plant or such other amount as approved by the NHPUC. Pursuant to an order issued by the NHPUC, PSNH can incur short-term debt up to $100 million. In the absence of an NHPUC order, PSNH's short-term debt limits are subject to periodic approval by the SEC under the 1935 Act.

(3) Pursuant to a DTE order, WMECO can lend through the Money Pool only to CL&P, HWP, NNECO, Quinnehtuk and Rocky River Realty, Inc. (RRR).

(4) Includes RRR, Quinnehtuk, Yankee Financial, YESCO, NorConn Properties, Inc., NUEI, NGS, Boulos, Woods Electrical, Select Energy, NAEC, Northeast Nuclear Energy Company (NNECO), Select Energy New York, Inc., SESI and Properties, Inc.

Debt Issuance Limitations

CL&P's charter contains preferred stock provisions restricting the amount of additional unsecured debt it may incur. At shareholders' meetings in November 2003, CL&P obtained authorization from its preferred stockholders to issue unsecured indebtedness with a maturity of less than ten years in excess of ten percent of capitalization (but not in excess of 20 percent of capitalization) for a ten-year period expiring March 2014. As of December 31, 2004, the amount of additional unsecured debt it could incur was $394.8 million.

CL&P's first mortgage bond indenture provides that additional bonds may not be issued based on bondable property additions, except for certain refunding purposes, unless: (i) net earnings during a period of twelve consecutive calendar months during the period of fifteen consecutive calendar months immediately preceding the first day of the month in which the application for additional bonds is made are at least twice the pro forma annual interest charges on outstanding bonds, certain prior lien obligations and bonds to be issued, and (ii) CL&P has available property credits equal to 166 2/3 percent of the principal amount of bonds to be issued. The indenture also allows CL&P to issue first mortgage bonds equal to the available amount of bonds previously issued but retired. At December 31, 2004, CL&P could not issue any bonds based on bondable property additions, but could issue up to approximately $405.4 million based on available retired bond credits.

Yankee Gas' first mortgage bond indenture also provides that additional bonds may not be issued based on bondable property additions, except for certain refunding purposes, unless: (i) net earnings during a period of twelve consecutive calendar months during the period of fifteen consecutive calendar months immediately preceding the first day of the month in which the application for additional bonds is made are at least twice the pro forma annual interest charges on outstanding bonds, certain prior lien obligations and bonds to be issued and (ii) Yankee Gas has available property credits equal to 166 2/3 percent of the principal amount of bonds to be issued. The

indenture also allows Yankee Gas to issue first mortgage bonds equal to the available amount of bonds previously issued but retired, but subject under certain conditions to meeting the net earnings for interest test just described. Yankee Gas would need to meet this test to issue first mortgage bonds based on any of its currently available prior redeemed bonds. As of December 31, 2004, Yankee Gas' net earnings were 2.26 times the annual interest charges on its outstanding bonds. Yankee Gas anticipates passing this interest coverage test after accounting for its planned issuance of $50 million in 2005 and issuing this debt under its first mortgage bond indenture. If Yankee Gas is unable to pass this issuance test, it would need to issue junior debt which would not have the security of the first mortgage bond indenture.

Limitations on Liens

NU's supplemental indentures under which it issued $175 million in principal amount of 8.58 percent amortizing notes in December 1991 and $75 million in principal amount of 8.38 percent amortizing notes in March 1992 contain restrictions on dispositions of certain NU system companies' stock, limitations of liens on NU assets and restrictions on distributions on and acquisitions of NU stock. Under these provisions, NU, CL&P, PSNH and WMECO may not dispose of voting stock of CL&P, PSNH or WMECO other than to NU or another NU system company, except that CL&P may sell voting stock for cash to third persons if so ordered by a regulatory agency so long as the amount sold is not more than 19 percent of CL&P's voting stock after the sale. The restrictions also generally prohibit NU from pledging voting stock of CL&P, PSNH or WMECO or granting liens on its other assets in amounts greater than five percent of the total common equity of NU. As of December 31, 2004, no NU debt was secured by liens on NU assets. Furthermore, NU may not declare or make distributions on its capital stock, acquire its capital stock (or rights thereto), or permit an NU system company to do the same, at times when there is an event of default existing under the supplemental indentures under which the amortizing notes were issued.

The indenture under which NU issued $263 million in principal amount of 7.25 percent notes in April 2002 and $150 million in principal amount of 3.30 percent notes in June 2003 contains a limitation on liens on NU assets and a limitation on sale and leaseback transactions involving those assets.

WMECO's debt indenture, under which it issued $55 million in principal amount of 5.00 percent notes in September 2003 and $50 million in principal amount of 5.90 percent notes in September 2004, contains similar restrictions.

Many of the NU system companies' financing agreements have similar restrictions on liens.

Preferred Stock Issuance Limitations

CL&P's charter has provisions that prohibit the issuance of additional preferred stock (except for refinancing purposes) unless income before interest charges (as defined and after income taxes and depreciation) is at least 1.5 times the pro-forma annual interest charges on indebtedness and the annual dividend requirements on preferred stock that will be outstanding after the additional stock is issued. At December 31, 2004, CL&P's income before interest charges was approximately 2.46 times the pro-forma annual interest and preferred dividend requirements. CL&P has no current plans to issue any preferred stock.

Dividend Payment Limitations

Certain consolidated subsidiaries have dividend restrictions imposed by their long-term debt agreements. These restrictions also limit the amount of retained earnings available for NU common dividends. At December 31, 2004, retained earnings available for the payment of dividends totaled $343.5 million.

The Federal Power Act and the 1935 Act limit the payment of dividends by PSNH, CL&P, WMECO and Yankee Gas to retained earnings. At December 31, 2004, retained earnings for these companies were $243.3 million, $347.2 million, $77.6 million and $52.0 million, respectively.

CL&P's first mortgage bond indenture limits dividend payments and share repurchases to an amount equal to (i) retained earnings accumulated after December 31, 1966; plus (ii) retained earnings accumulated prior to January 1, 1967, not exceeding $13.5 million; plus (iii) any additional amounts authorized by the SEC. Currently, there are no additional amounts authorized by the SEC.

PSNH is also limited by New Hampshire statutes to the payment of dividends not exceeding the amount of retained earnings.

NGC's bond covenants prevent NGC from making dividend payments unless (i) no default or event of default will occur from doing so, (ii) the debt service reserve account has been sufficiently funded with six months of principal and interest on the outstanding bonds, and (iii) the debt service coverage ratio for the previous four fiscal quarters (or, if shorter, since the bond issuance closing date) and projected debt service coverage ratio for the next eight fiscal quarters is greater than or equal to (a) 1.35 if contracted generating capacity is greater than 75 percent or (b) 1.70 if contracted generating capacity is less than 75 percent. At December 31, 2004, NGC's contracted generating capacity was greater than 75 percent. NGC expects to meet its debt service coverage ratio requirements under this covenant

and to pay dividends in 2005.

Capitalization

NU and its electric utility subsidiaries are required under the 1935 Act to maintain their consolidated common equity at a level equal to at least 30 percent of their consolidated capitalization. In planning for the issuance of RRBs and RRCs by CL&P and PSNH in 2001, these companies obtained SEC consent for their common equity ratios to remain below 30 percent through December 31, 2006. As of December 31, 2004, NU's, CL&P's, WMECO's and PSNH's ratios were 31.9 percent, 28.4 percent, 33.8 percent and 30.4 percent, respectively. These ratios include RRBs and RRCs as debt.

Credit

NU provides credit assurance in the form of guarantees and letters of credit for the financial performance obligations of certain of its unregulated and regulated subsidiaries. NU currently has authorization from the SEC to provide up to $750 million of such guarantees for the benefit of its unregulated subsidiaries through June 30, 2007. As of December 31, 2004, the amount of guarantees outstanding under this limit was $359 million. NU has also issued indirect guarantees of its regulated companies by issuing guarantees to surety companies. These guarantees for the regulated companies are subject to a separate $50 million SEC limitation apart from the $750 million guarantee limit. As of December 31, 2004, $13 million of guarantees were outstanding for the regulated entities. As of December 31, 2004, NU had $34 million of letters of credit issued for the benefit of the unregulated subsidiaries.

At December 31, 2004, the maximum level of exposure in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," (FIN 45), under guarantees by NU, primarily on behalf of NUEI, totaled $1.1 billion. Computations under FIN 45 include all exposures even though they are not reasonably likely to result in exposure to NU.

On October 19, 2004, the SEC authorized NU to issue guarantees of up to an aggregate $100 million through June 30, 2007 of the debt or other obligations of two of its subsidiaries, NUSCO and RRR. These companies provide certain specialized support and real estate services to the entire NU system and occasionally enter into transactions that require financial backing from NU. The amount of guarantees outstanding in compliance with the SEC limit under this category at December 31, 2004 was $230,000.

Ratings Triggers

Certain NU system credit financing agreements have trigger events tied to the credit ratings of certain NU system companies, as discussed below.

NU and its subsidiaries have $900 million of revolving credit agreements with a number of banks. There are no ratings triggers that would result in a default, but lower ratings could increase interest on future borrowings from the credit lines.

Select Energy has certain contracts that require the posting of additional collateral in the form of cash or letters of credit in the event NU's ratings were to decline and in increasing amounts dependent upon the severity of the decline. Select Energy has not had to post any collateral based on NU's credit downgrades. Were NU's unsecured ratings to decline two levels to sub-investment grade, Select Energy could, under its present contracts, be asked to provide approximately $361 million of collateral or letters of credit to various unaffiliated counterparties as of December 31, 2004, and approximately $140 million to several independent system operators and unaffiliated local distribution companies as of December 31, 2004, which management believes NU would currently be able to provide. NU's credit ratings outlooks are currently stable or negative, but management does not believe that at this time there is a significant risk of a ratings downgrade to sub-investment grade levels.

NGC has a debt reserve account related to its two senior secured debt series that can be funded with cash, an NU guarantee or a letter of credit (LOC) from an acceptable counterparty. The account may be funded with a guarantee from NU if NU has an investment grade rating by Standard & Poor's and Moody's. While NU does have investment grade ratings, the debt service reserve account is currently funded with cash.

RRR is a real estate subsidiary that owns NU's Connecticut headquarters site. As of December 31, 2004, it had approximately $3.8 million of debt outstanding that could be affected by a ratings change. If NU, CL&P, PSNH or WMECO ratings fall below a B1 Moody's rating or a B+ Standard & Poor's rating, bondholders would have the right to demand mandatory prepayments.

CONSTRUCTION AND CAPITAL IMPROVEMENT PROGRAM

The NU system's construction program expenditures are estimated to total $740 million in 2005. Of such total amount, approximately $420 million is expected to be expended by CL&P, $150 million by PSNH, $70 million by Yankee Gas, $40 million by WMECO and up to $60 million by other system entities. This construction program data includes all anticipated costs necessary for committed projects and for those reasonably expected to become committed projects in 2005, regardless of whether the need for the project arises from environmental compliance, reliability requirements or other causes. The construction program's main focus is maintaining, upgrading and expanding the existing transmission and distribution system and natural gas distribution system. The system expects to evaluate its needs beyond 2005 in light of future developments, such as restructuring, industry consolidation, performance and other events.

The $60 million in construction expenditures planned for other system entities in 2005 includes $25 million for NUEI which is mostly due to forecast expenditures at HWP for installation of equipment to meet emission requirements and at NGC's pumped storage and hydroelectric facilities.

CL&P plans to invest approximately $1.1 billion by the end of 2009 to construct two new 345 KV transmission lines from inland Connecticut to Norwalk, Connecticut and another $60 million to $70 million to replace an existing 138 KV transmission line beneath Long Island Sound. The investment in transmission lines and continued upgrading of the electric distribution system are expected to increase CL&P's net investment in electric plant by approximately $2.4 billion over the 2005 through 2009 timeframe. If current plans are implemented on schedule, the NU system would likely require additional external financing to construct these projects. If all of the transmission projects are built as proposed, the NU system's net investment in electric transmission would increase to nearly $1.9 billion by the end of 2009. See "Regulated Electric Operations-Connecticut Retail Rates."

Yankee Gas will continue to emphasize system expansion of its natural gas distribution system in Connecticut and has recently received DPUC support for the installation of a 1.2 billion cubic foot liquid natural gas production and storage facility in Waterbury, Connecticut estimated to cost approximately $108 million. Yankee Gas signed a contract with Chicago Bridge and Iron of The Woodlands, Texas on October 15, 2004 to design and construct the facility. Construction activities began in March 2004. See "Connecticut Retail Rates" for information on Yankee Gas' DPUC filing and the related decision.

NUCLEAR ACTIVITIES

General

During 2004, certain NU system companies owned equity interests in three regional nuclear companies (the Yankee Companies) that separately own the Connecticut Yankee nuclear unit (CY), the Maine Yankee nuclear unit (MY), and the Yankee Rowe nuclear unit (Yankee Rowe). Yankee Rowe, CY and MY have been permanently removed from service and are being decontaminated and decommissioned.

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders of the Yankee Companies. Each Yankee Company owns a single nuclear generating unit. The stockholder-sponsors of each Yankee Company are responsible for proportional shares of the operating and decommissioning costs of the respective Yankee Company. CL&P's, PSNH's and WMECO's stock ownership percentages in the Yankee Companies are set forth below:

	CL&P	PSNH	WMECO	NU System
Connecticut Yankee Atomic Power Company (CYAPC)	34.5%	5.0%	9.5%	49.0%
Maine Yankee Atomic Power Company (MYAPC)	12.0%	5.0%	3.0%	20.0%
Yankee Atomic Electric Company (YAEC)	24.5%	7.0%	7.0%	38.5%

CL&P, PSNH and WMECO sold their shares of the Vermont Yankee Atomic Power Corporation (VYNPC), owner of the Vermont Yankee nuclear unit (VY), back to VYNPC in 2003. Prior to the sale of VY, NU subsidiaries owned 17 percent of VYNPC and, under the terms of the sale, will continue to buy 16 percent of VY's output through March 2012 at a range of fixed prices.

The NRC has broad jurisdiction over the design, construction and operation of nuclear generating stations, including the decommissioning activities at the Yankee Companies.

Nuclear Fuel

General

Nuclear fuel costs associated with nuclear plant operations include amounts for disposal of spent nuclear fuel. The NU system companies include in their nuclear fuel expense those spent fuel disposal costs accepted by the DPUC, NHPUC and DTE in rate case or fuel adjustment decisions. Spent fuel disposal costs also are reflected in the FERC-approved wholesale charges.

High-Level Radioactive Waste

The Nuclear Waste Policy Act of 1982 (NWPA) provides that the federal government is responsible for the permanent disposal of spent nuclear reactor fuel (SNF) and other high-level waste. As required by the NWPA, electric utilities generating SNF and high-level waste are obligated to pay fees into a fund which would be used to cover the cost of siting, constructing, developing and operating a permanent disposal facility for this waste. The NU system companies have been paying for such services for fuel burned on or after April 7, 1983, on a quarterly basis since July 1983. The DPUC, NHPUC and DTE permit the fee to be recovered through rates. For nuclear fuel used to generate electricity prior to April 7, 1983 (prior-period fuel), payment must be made upon the first delivery of spent fuel to the United States Department of Energy (DOE). The DOE's current estimate for an available site is 2010 at the earliest.

In 2002, Congress designated the Yucca Mountain site in Nevada as the nation's repository for used nuclear fuel. In return for payment of the fees prescribed by the NWPA, the federal government is to take title to and dispose of the utilities' high-level wastes and SNF. There have been numerous litigation proceedings involving DOE's statutory and contractual obligation to accept high-level waste and SNF. While the courts have declined to order the DOE to begin accepting spent fuel for disposal on January 31, 1998, the courts have left open the utilities' ability to bring damage claims against the DOE.

In 1998, YAEC, CYAPC and MYAPC filed separate complaints against the DOE in the United States Court of Federal Claims seeking monetary damages resulting from DOE's failure to accept spent nuclear fuel for disposal. In decisions later that year, the court found liability on the part of DOE to the companies for breach of the standard contract, based upon DOE's failure to begin disposal of spent nuclear fuel. The damages owed to YAEC, CYAPC and MYAPC as a result of DOE's failure to begin disposing of spent nuclear fuel is in litigation and the trial addressing these issues concluded on August 31, 2004. Final post-trial briefs were filed on January 28, 2005. During the course of the trial the government filed a motion seeking permission to file a counterclaim against CYAPC and MYAPC seeking to offset the pre-1983 monies the companies are holding against any potential damage award in this litigation. Both MYAPC and CYAPC filed their responses on September 24, 2004. The court's ruling on that matter is expected to be issued in the same time frame as its overall ruling in the case.

On January 23, 2004, Dominion Nuclear Connecticut, Inc. (DNCI) and Dominion Resources, Inc., on behalf of themselves, CL&P, WMECO and NUSCO, filed a similar complaint in the United States Court of Federal Claims against DOE, with respect to DOE's failure to accept spent nuclear fuel for disposal from the Millstone nuclear power station. The complaint is subject to an automatic stay imposed by the United States Court of Federal Claims until the lead cases (including the case filed by CYAPC) go to trial on their damages claims.

Until the federal government begins accepting nuclear waste for disposal, nuclear generating plants will need to retain high-level waste and spent fuel onsite or make some other provisions for its storage.

Construction of on-site dry spent fuel storage facilities, to hold the spent nuclear fuel and other high level waste generated at those facilities until the DOE accepts this waste, is complete at Yankee Rowe and MY and in progress at CY. As of February 1, 2005, 33 of 43 storage canisters have been moved to the dry storage facility site at CY, with targeted completion planned by the summer of 2005. All of the spent fuel has been transferred to the storage facility at MY as of February 2004. All of the spent fuel at Yankee Rowe has been moved to the storage site as of June 2003.

Decommissioning

As a result of the sales of Millstone in 2001 and Seabrook and the VY nuclear units in 2002, respectively, NU shareholders, the NU system companies and their ratepayers have no further obligation related to decommissioning with respect to those units. NU still has significant decommissioning and plant closure cost obligations to the Yankee Companies. The Yankee Companies collect decommissioning and closure costs through wholesale FERC-approved rates charged under power purchase agreements to CL&P, PSNH and WMECO and the other non-NU sponsor companies. These companies in turn pass these costs on to their customers through state regulatory commission-approved retail rates.

During 2002, NU was notified by CYAPC, YAEC and MYAPC that the estimated cost of decommissioning these units and other closure costs increased over prior estimates due to higher anticipated costs for spent fuel storage, security and liability and property

insurance. NU's share of these increases is $177.1 million.

NU cannot at this time predict the timing or outcome of the FERC proceeding required for the collection of these remaining decommissioning and closure costs. Although management believes that these costs will ultimately be recovered from the customers of CL&P, PSNH and WMECO, there is a risk that the FERC may not allow these costs, the estimates of which have increased significantly since 2002, to be recovered in wholesale rates. If the FERC does not allow these costs to be recovered in wholesale rates, NU would expect the state regulatory commissions to disallow those costs in retail rates as well. As owners of equity investments in CYAPC, CL&P, PSNH and WMECO are subject to losses if CYAPC is not successful in rate proceedings at the FERC.

YAEC, MYAPC and CYAPC are currently collecting revenues for the decommissioning of the related sites through their power purchase agreements. YAEC ceased decommissioning collections in June 2000 but began collections again on June 1, 2003. The table below sets forth the NU system companies' estimated share of remaining decommissioning costs of the Yankee Companies' units as of December 31, 2004, net of amounts collected in rates. The estimates are based on the latest decommissioning cost estimates. For information on the equity ownership of the NU system companies in each of the Yankee Companies' units, see "Nuclear Activities-General."

	CL&P	PSNH	WMECO	NU System
		(Millions)		
CY*	$ 125.1	$ 18.1	$ 34.5	$ 177.7
MY*	35.0	14.6	8.8	58.4
Rowe*	39.4	11.3	11.3	62.0
Total	$ 199.5	$ 44.0	$ 54.6	$ 298.1

* The costs shown include the expected future revenue requirements associated with the funding of decommissioning, recovery of remaining assets and other closure costs associated with the early retirement of Yankee Rowe, CY and MY as of December 31, 2004, which have been recorded as an obligation on the books of the NU system companies.

As of December 31, 2004, the Yankee Companies' share of the external decommissioning trust fund balances (at market), reflecting the contribution share provided by the NU system companies, is as follows:

	CL&P	PSNH	WMECO	NU System
		(Millions)		
CY	$ 23.4	$ 3.4	$ 6.5	$ 33.3
MY	6.8	2.8	1.7	11.3
Rowe	11.3	3.2	3.2	17.7
Total	$ 41.5	$ 9.4	$ 11.4	$ 62.3

CYAPC's estimated decommissioning and plant closure costs for the period 2000 through 2023 have increased by approximately $395 million over the April 2000 estimate of $436 million approved by the FERC in a 2000 rate case settlement. On July 1, 2004, CYAPC filed with the FERC for recovery of these increased costs. In the filing, CYAPC sought to increase its annual decommissioning collections from $16.7 million to $93 million for a six-year period beginning on January 1, 2005. On August 30, 2004, the FERC issued an order accepting the rates, with collection beginning on February 1, 2005, subject to refund, and scheduled hearings for May 2005. Related hearings associated with actions brought by certain interveners are currently ongoing. For further information on this proceeding, see Item 3, "Legal Proceedings."

YAEC filed with the FERC in April 2003 for its unrecovered decommissioning costs. A settlement was approved by the FERC on October 2, 2003 and collections began on June 1, 2003. YAEC is to return to the FERC in 2006 to update its estimate. MYAPC filed with the FERC in October 2003 for new rates and reached a settlement with the FERC and intervening parties in September 2004 for total annual collections of approximately $27 million annually through October 2008.

In June 2003, CYAPC terminated its contract with Bechtel Power Corporation (Bechtel) for the decommissioning of CY. For information on litigation between CYAPC and Bechtel relating to the termination of this contract, see Item 3, "Legal Proceedings."

In October 2001, NU issued a report, following an extensive search, concerning two missing fuel pins at the retired Millstone 1 nuclear unit which was subsequently sold to DNCI. As of December 31, 2004, costs related to this search totaled $9.4 million. The report concluded that the pins are currently located in one of four facilities licensed to store low or high-level nuclear waste and that they are not a threat to public health and safety. A follow-up inspection by the NRC concluded that NU's investigation was thorough and complete and its conclusions were reasonable and supportable. These events resulted in the issuance of an NRC notice of violation and the imposition of a $288,000 civil penalty in 2002. The NRC concluded its review of this matter in April 2004, stating that additional efforts to locate the rods were unwarranted.

Environmental Regulation

General

The NU system and its subsidiaries 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, the NU system's major generation and transmission facilities may not be constructed or significantly modified without a review by the applicable state agencies of the environmental impact of the proposed construction or modification. Compliance with increasingly more stringent environmental laws and regulations, particularly air and water pollution control requirements, may limit operations or require substantial investments in new equipment at existing facilities.

Surface Water Quality Requirements

The federal Clean Water Act requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the United States Environmental Protection Agency (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. NU system facilities are in the process of obtaining or renewing all required NPDES or state discharge permits in effect. Compliance with NPDES and state discharge permits has necessitated substantial expenditures, which are difficult to estimate, and may require further significant expenditures because of additional requirements or restrictions that could be imposed in the future, including requirements related to Sections 316(a) and 316(b) of the Clean Water Act for facilities owned by PSNH and HWP. For information regarding civil lawsuits related to alleged violations of certain facilities' NPDES permits, see Item 3, "Legal Proceedings."

The Federal Oil Pollution Act of 1990 (OPA 90) sets out the requirements for facility response plans and periodic inspections of spill response equipment at facilities that can cause substantial harm to the environment by discharging oil or hazardous substances into the navigable waters of the United States and onto adjoining shorelines. The NU system companies are currently in compliance with the requirements of OPA 90. OPA 90 includes limits on the liability that may be imposed on persons deemed responsible for release of oil. The limits do not apply to oil spills caused by negligence or violation of laws or regulations. OPA 90 also does not preempt state laws regarding liability for oil spills. In general, the laws of the states in which the NU system owns facilities and through which the NU system transports oil could be interpreted to impose strict liability for the cost of remediating releases of oil and for damages caused by releases. The NU system currently carries general liability insurance in the total amount of $160 million annual coverage, which includes liability coverage for oil spills.

Air Quality Requirements

The Clean Air Act Amendments of 1990 (CAAA), as well as state laws in Connecticut, Massachusetts and New Hampshire, impose stringent requirements on emissions of sulfur dioxide (SO2) and nitrogen oxide (NOX) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA address the control of toxic air pollutants. Installation of continuous emissions monitors and expanded permitting provisions also are included. Compliance with CAAA requirements cost the NU system approximately $24 million during 2004: approximately $21 million for PSNH and approximately $3 million for HWP.

Massachusetts and New Hampshire are both imposing significant new emission reduction requirements on power plants, in addition to the Federal requirements. In Massachusetts, new emission standards for power plants were signed into law in September 2001. The four pollutants regulated under these standards are NOX, SO2, carbon dioxide (CO2) and mercury, with some limits and requirements effective in October 2006 and other limits and requirements effective in 2008 and 2012. Interim limits for NOX and SO2 were also set for HWP. The mercury standards were finalized in June 2004. The capital cost for Mt. Tom Station to meet current and known future Massachusetts emission reduction limits and requirements is estimated to be approximately $14 million if a selective catalytic reduction (SCR) system is installed to meet the new emission standards. Completion of this work will reduce Mt. Tom's NOX emissions, thus lowering the amount of NOX allowances required compared to prior years. SO2 requirements will be met by purchasing lower sulfur coals. Additional costs for compliance with mercury requirements are unknown at this time.

In New Hampshire, the Multiple Pollutant Reduction Program was signed into law in May 2002. This law addresses emissions reductions of the same four pollutants as in Massachusetts. NOX, SO2 and CO2 have their emission caps established for current compliance beginning in 2007. The mercury emission cap is expected to be considered by the legislature by July 1, 2005. Estimates for additional compliance costs (excluding mercury control) are between $20 and $25 million dollars and will be better known after the mercury reduction requirement is established.

Hazardous Materials Regulations

As many other industrial companies have done in the past, the NU system companies disposed of residues from operations by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, ash, gasoline and other hazardous materials that might contain polychlorinated biphenyls (PCBs). It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. The NU system has recorded a liability for what it believes is, based upon currently available information, its estimated environmental investigation and/or remediation costs for waste disposal sites for which the NU system companies expect to bear legal liability, and continues to evaluate the environmental impact of its former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on NU system companies for such past disposal. At December 31, 2004, the liability recorded by the NU system for its estimated environmental remediation costs for known sites needing investigation and/or remediation, including those sites described below, exclusive of recoveries from insurance or from third parties, was approximately $38.7 million, representing 53 sites. This total includes liabilities recorded by Yankee Gas of approximately $19.1 million. All cost estimates were made in accordance with generally accepted accounting principles where investigation and/or remediation costs are probable and reasonably estimable. These costs could be significantly higher if additional remedial actions become necessary. These liabilities break down as follows:

1. Under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, commonly known as Superfund, EPA has the authority to clean up or order the clean up of hazardous waste sites and to impose the clean up costs on parties deemed responsible for the hazardous waste activities on the sites. Responsible parties include the current owner of a site, past owners of a site at the time of waste disposal, waste transporters and waste generators. As of December 31, 2004, the NU system was involved in five Superfund matters: one in Connecticut, one in New Jersey, two in New Hampshire and one in Kentucky, which could have a material impact on the NU system. The NU system has established a reserve of approximately $1.1 million for its share of the clean up of these sites. For further information on litigation relating to the Connecticut matter, see Item 3, "Legal Proceedings."

2. The greatest liabilities currently relate to former manufactured gas plant (MGP) facilities which represent the largest share of future clean up costs. These facilities were owned and operated by predecessor companies to the NU system from the mid-1800's to mid-1900. Byproducts 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. The NU system currently has partial or full ownership responsibilities at 29 former MGP sites. Of the total NU system liabilities, a reserve of approximately $33.2 million has been established to address future investigation and/or remediation costs at MGP sites.

3. Other sites undergoing and/or anticipating comprehensive investigations or remediation actions under state programs located in Connecticut, Massachusetts or New Hampshire include two former fuel oil releases, two landfills, three asbestos hazard abatement projects and twelve miscellaneous projects. To date, a reserve of approximately $4.5 million has been established to address future investigation and/or remediation costs at these sites.

In the past, the NU system has received other claims from government agencies and third parties for the cost of remediating sites not currently owned by the NU system but affected by past NU system disposal activities and may receive more such claims in the future. The NU system expects that the costs of resolving claims for remediating sites about which it has been notified will not be material, but cannot estimate the costs with respect to sites about which it has not been notified.

For further information on environmental liabilities, see Footnote 6B, "Commitments and Contingencies – Environmental Matters" contained within NU's 2004 Annual Report to Shareholders, which is incorporated into this Form 10-K by reference.

Electric and Magnetic Fields

Published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Most researchers, as well as numerous scientific review panels considering all significant EMF epidemiological and laboratory studies to date, agree that current information remains inconclusive, inconsistent and insufficient for characterizing EMF as a health risk.

Based on this information, management does not believe that a causal relationship between EMF exposure and adverse health effects has been established or that significant capital expenditures are appropriate to minimize unsubstantiated risks. The NU system companies have closely monitored research and government policy developments for many years and will continue to do so.

If further investigation were to demonstrate that the present electricity delivery system is contributing to increased risk of cancer or other health problems, the industry could be faced with the difficult problem of delivering reliable electric service in a cost-effective manner while managing EMF exposures. To date, no courts have concluded that individuals have been harmed by EMF from electric utility facilities, but if utilities were to be found liable for damages, the potential monetary exposure for all utilities, including the NU

system companies, could be enormous. Without definitive scientific evidence of a causal relationship between EMF and health effects, and without reliable information about the kinds of changes in utilities' transmission and distribution systems that might be needed to address the problem, if one is found, no estimates of the cost impacts of remedial actions and liability awards are available.

In addition, the CSC held hearings in January 2005 to assess proposals for mitigating EMF associated with certain of NU's proposed new overhead transmission lines. For information on these hearings, see "Regulated Electric Operations – Connecticut Retail Rates – CL&P Transmission Projects."

FERC Hydroelectric Project Licensing

New Federal Power Act licenses may be issued for hydroelectric projects for terms of 30 to 50 years as determined by the FERC. Upon the expiration of an existing license, (i) the FERC may issue a new license to the existing licensee, or (ii) the United States may take over the project or 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.

The NU system companies currently hold the FERC licenses for 11 hydroelectric projects totaling 16 plants. In addition, the NU system companies own and operate five unlicensed hydroelectric projects that are currently deemed non-jurisdictional by the FERC. These licensed and unlicensed hydroelectric projects are located in Connecticut, Massachusetts and New Hampshire and aggregate approximately 1,367 MW of capacity. NGC owns four licensed and four unlicensed projects with approximately 1,296 MW capacity. PSNH owns nine hydroelectric generating stations with an aggregate of approximately 68.1 MW of capacity.

On June 23, 2004 a single, new 40-year license was issued to NGC for the 109.8 MW Housatonic hydroelectric project and the 11 MW Falls Village project. The new license incorporates the terms and conditions of the CDEP 401 water quality certification. The license and water quality certificate require operation of the Falls Village and Bulls Bridge projects in run of river mode and specify minimum flow releases for the by pass reaches at these projects, and minimum flow releases at the Stevenson project and Shepaug projects. Upstream and downstream fish passage facilities for the Stevenson project must be designed by 2011 and constructed by 2014. Fish passage facilities for the Shepaug and Bulls Bridge projects must be designed by 2021 and completed by 2024. Interim upstream eel passage facilities at the Stevenson project must be operational in 2005. The license also requires that NGC prepare and implement a number of project plans, including recreation, shoreline management, critical habitat management, debris management, nuisance plant monitoring and historic property management plans.

PSNH's FERC license for the Merrimack River Hydroelectric Project that consists of the Amoskeag, Hooksett and Garvins Falls hydroelectric generating stations expires on December 31, 2005. In December 2003, PSNH filed an application for a new license for the project. The FERC's most recent relicensing schedule provides for issuance of notice that the application is ready for environmental review in March 2005; availability of an environmental assessment in August 2005 and readiness for commission decision in November 2005. If a new license is not issued by the expiration of the current license (December 31, 2005), it is expected that the FERC will issue an annual license for the project. Annual licenses are commonly issued under the same terms and conditions as the current license, but may include new conditions if such conditions are authorized by the existing license.

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

At this time, it appears unlikely that the FERC will order decommissioning of NGC or PSNH hydroelectric projects at relicensing or that the projects will be abandoned, surrendered or the project licenses revoked. However, it is impossible to predict the outcome of the FERC relicensing proceedings with certainty, or to determine the impact of future regulatory actions on project economics. Until such time as a project is ordered to be decommissioned and the terms and conditions of a decommissioning order are known, it is not possible to accurately estimate or predict the cost of project decommissioning.

EMPLOYEES

As of December 31, 2004, the NU system companies had 7,079 employees on their payrolls, excluding temporary employees, of which 2,239 were employed by CL&P, 1,297 by PSNH, 409 by WMECO, 472 by Yankee Gas, 229 by NGS, 1,571 by NUSCO, 170 by Select, 123 by SESI, 521 by SECI, 24 by Boulos, 10 by Woods Electric and 14 by Woods Network. NU, NGC, NAEC, Mode 1 and NUEI have no employees. There could be some impact on employees at the competitive wholesale and services businesses due to NU's March 9, 2005 decision to exit those businesses.

Approximately 2,450 employees of CL&P, PSNH, WMECO, HWP, NGS and Yankee Gas are covered by 15 union agreements. In 2004, five contracts were negotiated (including three major physical worker contracts in Connecticut and Western Massachusetts) which are expected to result in labor stability through 2009 and 2010, respectively. In addition to the continuing negotiation of several smaller contracts from 2004, NU expects to negotiate two Yankee Gas contracts and two dispatcher contracts in the summer and fall of 2005, respectively.

INTERNET INFORMATION

The NU system's Web site address is http://www.nu.com/investors. The company makes available through its Web site a link to the SEC's EDGAR site, at which site NU's, CL&P's, WMECO's and PSNH's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports may be reviewed. Printed copies of these reports may be obtained free of charge by writing to the Company's Investor Relations Department at Northeast Utilities, 107 Selden Street, Berlin, Connecticut 06037.

Item 2. Properties

The physical properties of NU are owned or leased by subsidiaries of NU. CL&P's properties are located either on land which is owned in fee or on land, as to which CL&P owns perpetual occupancy rights adequate to exclude all parties except possibly state and federal governments, which has been reclaimed and filled pursuant to permits issued by the United States Army Corps of Engineers. The principal properties of PSNH are held by it in fee. A major portion of WMECO's properties are owned in fee. In addition, CL&P, PSNH and WMECO lease certain data processing equipment, vehicles, and office space. Also CL&P and WMECO lease certain substation equipment. With few exceptions, NU's lines are located on or under streets or highways, or on properties either owned or leased, or in which they have appropriate rights, easements, licenses or permits from the owners or the appropriate governmental authorities.

Yankee Gas' property consists primarily of its natural gas distribution facilities including distribution lines (mains and services), meters, valves, pressure regulators and flow controllers. Yankee Gas also owns five propane peak-shaving facilities with a combined storage capacity equivalent to approximately 206,000 million cubic feet and service buildings and rents or leases certain other property. Yankee Gas plans to remove one of the propane peak shaving facilities from service in 2005 which will reduce the combined storage capacity to 170,000 million cubic feet.

CL&P, PSNH, WMECO, NGC and Yankee Gas' properties are subject to the lien of each company's respective first mortgage indentures. In addition, CL&P's interest in transmission assets is subject to a second mortgage lien for the benefit of the PCRBs. Various properties are also subject to minor encumbrances which do not substantially impair the usefulness of the properties to the owning company.

NU's properties are well maintained and are in good operating condition.

Transmission and Distribution System

At December 31, 2004 NU owned 109 transmission and 340 distribution substations that had an aggregate transformer capacity of 18,177,573 kilovoltamperes (kVa) and 9,107,163 kVa, respectively; 3,081 circuit miles of overhead transmission lines ranging from 69 kilovolt (kV) to 138 kV, and 196 cable miles of underground transmission lines ranging from 69 kV to 138 kV; 2,623 pole miles of overhead and 44 conduit bank miles of underground distribution lines; and 458,390 line transformers in service with an aggregate capacity of 20,899,000 kVa.

Electric Generating Plants

As of December 31, 2004, the electric generating plants of NU were as follows:

Owner	Name of Plant (Location)	Type	Year Installed	Claimed Capability* (kilowatts)
PSNH	Total - Fossil-Steam Plants	(7 units)	1952-78	999,554
	Total - Hydro-Conventional	(20 units)	1917-83	67,810
	Total - Internal Combustion	(5 units)	1968-70	100,228
	Total PSNH Generating Plant	(32 units)		1,167,592
HWP	Total - Fossil-Steam Plants	(1 unit)	1960	146,369
NGC	Total - Hydro-Conventional	(36 units)	1903-55	166,329
	Total - Hydro-Pumped Storage	(7 units)	1928-73	1,109,010
	Total - Internal Combustion	(1 unit)	1969	20,800
	Total NGC Generating Plant	(44 units)		1,296,139
NU	Total - Fossil-Steam Plants	(8 units)	1952-78	1,145,923
	Total - Hydro-Conventional	(56 units)	1903-83	234,139
	Total - Hydro-Pumped Storage	(7 units)	1928-73	1,109,010
	Total - Internal Combustion	(6 units)	1968-70	121,028
Total NU Generating Plant		(77 units)		2,610,100

*Claimed capability represents winter ratings as of December 31, 2004.

Franchises

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

In addition to the right to provide electric transmission and distribution services as set forth above, the franchises of CL&P include, among others, limited rights and powers, as set forth in Title 16 of the Connecticut General Statutes and the special acts of the General Assembly constituting its charter, to manufacture, generate, purchase and/or sell electricity at retail, including to provide transitional standard offer, backup, and default service, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain. Title 16 of the Connecticut General Statutes was amended, however, by Public Act 03-135, "An Act Concerning Revisions to the Electric Restructuring Legislation," to prohibit an electric distribution company from owning or operating generation assets. CL&P has divested all of its generation assets and is now acting as a transmission and distribution company. See "Regulated Electric Operations - Rates - General" for more information on electric industry restructuring.

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

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

WMECO - WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted

are not vested. Such locations are for specific lines only, and for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority and pursuant to state laws, has the power of eminent domain.

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

HWP and HP&E - HWP, and its wholly owned subsidiary HP&E, are authorized by their charters to conduct their businesses in the territories served by them. HWP's electric business is subject to the restriction that sales be made by written contract in amounts of not less than 100 horsepower to purchasers who use the electricity in their own business in the counties of Hampden or Hampshire, Massachusetts and cities and towns in these counties, and customers who occupy property in which HWP has a financial interest, by ownership or purchase money mortgage. The two companies have locations in the public highways for their transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. HP&E has no retail service territory area and sells electric power exclusively at wholesale. In connection with the sale of certain of HWP's and HP&E's assets to the city of Holyoke Gas and Electric Department (HG&E) effective December 2001, HWP agreed to cause the charters of HWP and HP&E to be amended to eliminate their rights to distribute electricity at retail in Holyoke and surrounding towns unless other sellers can legally compete with HG&E, and not to exercise such rights prior to such amendment.

NGC - NGC is an exempt wholesale generator (EWG) and, as it currently operates its business, is not regulated by the DPUC or the DTE. The FERC's authorization for EWGs such as NGC to sell wholesale electric power at market-based rates typically contains an exemption from much of the traditional public utility company rate regulation. As an EWG, NGC is a "public utility" subject to the Federal Power Act. The market-based rate authorization that NGC has received from the FERC exempts NGC from some, but not all, of Federal Power Act regulations, including traditional cost-based rate regulation. However, NGC is required to file summary information concerning its power transactions on a quarterly basis with FERC.

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

Item 3. Legal Proceedings

1. Consolidated Edison, Inc. v. NU - Merger Related Litigation and Appeal

On March 5, 2001, Con Edison advised NU that it was unwilling to close its then-pending merger with NU on the terms set forth in the parties' merger agreement dated October 13, 1999 (the Merger Agreement). That same day, NU notified Con Edison that it would treat Con Edison's refusal to proceed with the merger as a repudiation and breach of the Merger Agreement and would file suit to obtain the benefits of the transaction for NU shareholders.

On March 6, 2001, Con Edison filed suit in the United States District Court for the Southern District of New York (the District Court) seeking a declaratory judgment that it had been relieved of its obligation to proceed with the merger due to, among other things, NU's alleged breach of the Merger Agreement and the alleged occurrence of a "Material Adverse Change" with respect to NU, as that term is defined in the Merger Agreement. On March 12, 2001, NU filed suit against Con Edison in the District Court seeking damages in excess of $1 billion arising from Con Edison's breach of the Merger Agreement.

On May 11, 2001, Con Edison filed an amended complaint in the action it had commenced on March 6, 2001, in which it added claims seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation in an unspecified amount, but which Con Ed's Chief Financial Officer has since testified is at least $314 million. On June 1, 2001, NU answered Con Edison's amended complaint, denying all of its material allegations and asserting affirmative defenses, and asserted a counterclaim seeking damages in excess of $1 billion against Con Edison for breach of the Merger Agreement. NU subsequently dismissed its March 12 complaint, without prejudice, since it was duplicative of the June 1 counterclaim filed in the Con Edison action. On June 8, 2001, Con Edison answered NU's counterclaim, denying its material allegations and asserting affirmative defenses.

The companies completed discovery in the litigation in 2002 and filed cross motions for summary judgment, which were decided by the District Court on March 14, 2003. The District Court granted NU's motion for summary judgment dismissing Con Edison's fraud and negligent misrepresentation claims, but in all other respects denied both parties' motions. Among other things, the District Court rejected Con Edison's argument that NU could not sue to recover the more than $1 billion merger premium on behalf of its shareholders, and held that NU shareholders were intended third-party beneficiaries of the Merger Agreement and that NU could sue to recover the merger premium on their behalf.

On July 24, 2003, Robert Rimkoski (Rimkoski), an alleged former NU shareholder who held NU common shares on March 5, 2001 (the day Con Edison repudiated the Merger Agreement) but sold them two days later, moved to intervene in the action on behalf of a putative class consisting of all persons who held NU shares on March 5, 2001, claiming that such persons and not NU's current shareholders are the proper third-party beneficiaries of the Merger Agreement and are entitled to any recovery awarded as a result of Con Edison's breach of the Merger Agreement. NU opposed Rimkoski's motion to intervene on the ground that he lacked standing. NU contended that the right to claim the merger premium, and the related right to sue for breach of the Merger Agreement, "ran with" NU shares and were thus sold by Rimkoski when he sold his NU shares, and that accordingly only current NU shareholders could assert a claim for the merger premium.

On December 24, 2003, the District Court granted Rimkoski's motion to intervene in the lawsuit as a defendant, but deferred a decision on the issue of whether Rimkoski's putative class of March 5, 2001 shareholders or NU's current shareholders are the proper third-party beneficiaries of the Merger Agreement. On January 5, 2004, NU filed a cross-claim against Rimkoski seeking a declaratory judgment that NU's current shareholders and not Rimkoski's putative class of March 5, 2001 shareholders are the proper third-party beneficiaries of the Merger Agreement.

In March 2004, NU moved for summary judgment on its cross-claim against Rimkoski. At the same time, Con Edison moved to dismiss NU's counterclaim against it, to the extent it sought damages on behalf of its current shareholders, arguing that only NU shareholders on March 5, 2001, such as Rimkoski, owned the right to pursue the third-party beneficiary contract claim against Con Edison. Rimkoski joined in Con Edison's motion.

In an order dated May 15, 2004, the District Court denied NU's motion for summary judgment on its cross-claim against Rimkoski and granted Con Edison's motion, holding that the claim for breach of the Merger Agreement belonged to NU shareholders as of March 5, 2001. However, recognizing that there was no precedent addressing this complex issue, the District Court *sua sponte* certified this issue for interlocutory review by the Second Circuit Court of Appeals (the Second Circuit) pursuant to 28 U.S.C. § 1292(b). The District Court also certified for interlocutory review its ruling, in its summary judgment opinion dated March 14, 2003, that NU shareholders were third-party beneficiaries of the Merger Agreement entitled to pursue a damage claim against Con Edison for the merger premium. In an order dated October 20, 2004, the Second Circuit agreed to review both issues certified by the District Court.

Briefing of the issues pending in the Second Circuit was completed in mid-February 2005. No date has yet been set by the Second Circuit for oral argument.

The District Court has not set a trial date in this action, and it is not possible to predict either the outcome or the ultimate effect on NU of any of the claims asserted by any of the parties thereto.

2. Sale of Millstone to Dominion Nuclear Connecticut Inc.

On March 8, 2001, the Connecticut Coalition Against Millstone (CCAM) and other parties filed a lawsuit in Connecticut Superior Court against the CDEP, NNECO and DNCI challenging (1) the validity of Millstone's NPDES permit (Permit) and a previously issued CDEP emergency authorization allowing Millstone to discharge wastewater not expressly authorized by the facility's Permit and (2) CDEP's authority to transfer both Millstone's permit and emergency authorization to DNCI. On March 29, 2001, CCAM's request for a temporary restraining order enjoining CDEP from transferring both the Permit and emergency authorization to DNCI prior to a full hearing was denied. Subsequently, on July 19, 2001, the entire matter was dismissed. On September 20, 2002, the Connecticut Supreme Court assigned the matter to itself. On December 23, 2003, the Connecticut Supreme Court dismissed CCAM's appeal. On January 2, 2004, CCAM filed a motion for reconsideration en banc, which was denied on February 4, 2004.

3. Retirement Plan Litigation

This matter involves four separate but related federal court lawsuits brought by nineteen former employees of NUSCO, WMECO and CL&P who retired between 1991 and 1994. The complaints generally allege that the companies breached their fiduciary duties to the plaintiffs by making affirmative misrepresentations that caused them to retire prematurely, since as a result of these alleged misrepresentations they came to believe incorrectly that no particular future enhancement of employee benefits was being seriously considered at the time by the companies. Plaintiffs are seeking the benefits of retirement plan enhancements adopted subsequent to their retirements.

The cases were tried together in a summary bench trial in the United States District Court in Hartford, Connecticut in April-May 2002. In a ruling issued on April 1, 2004, the judge found in favor of 15 of the19 plaintiffs and ordered NU to modify its retirement plan so as to include the successful plaintiffs in the special retirement plans at issue, retroactive to the dates of their retirement. NU withdrew its appeal of the court's decision, and reached a settlement with plaintiffs over interest and attorney's fees.

For further information on retirement-related matters, see Part I, Item 2, Note 4, of the "Notes to Consolidated Financial Statements."

4. Wisvest-Connecticut, LLC (Wisvest) v. Select Energy, Inc. and PSEG Power Connecticut LLC v. NU

Wisvest filed suit in July 2002 against Select Energy in the Superior Court at New Britain, Connecticut. In its complaint, Wisvest alleges that Select Energy breached its Load Asset Contract for Electrical Load dated November 23, 1999 (the Agreement), which contract expired on December 31, 2003, by unilaterally reducing the amount of electricity it proposed to purchase from Wisvest. The complaint seeks monetary damages and a declaratory judgment. Wisvest's claim against Select Energy is expected to be withdrawn as the price Wisvest was paid for the power not purchased by Select Energy was higher than what Select Energy paid under the Agreement.

Select Energy has filed an Answer to the complaint, denying any liability. It has also filed several special defenses and counterclaims to recover approximately $5.8 million plus interest for congestion charges incurred and paid by Select Energy prior to the implementation of SMD on March 1, 2003. Select Energy, pursuant to the contract, ultimately withheld from a final payment to Wisvest (now known as PSEG Power Connecticut LLC) approximately $6.5 million for the pre-SMD congestion and interest charges.

In a separate but related claim, PSEG Power Connecticut LLC brought suit against NU seeking to recover the $6.5 million withheld by Select Energy under an NU parent guaranty. The cases have been consolidated on the complex litigation docket in Connecticut Superior Court, where NU's discovery is currently underway. PSEG Power Connecticut LLC has moved for summary judgment on the parent guaranty; however, consideration of the motion was stayed by the court pending completion of discovery by Select Energy. Oral argument on PSEG Power Connecticut LLC's motion will be heard in April 2005. No trial date has been set.

5. Constellation Power Source, Inc. (Constellation) v. Select Energy, Inc.

This case involves a dispute between Select Energy and Constellation over responsibility for socialized congestion charges imposed by ISO-NE prior to the implementation of Standard Market Design (SMD) on March 1, 2003, and who is responsible for congestion and losses following implementation of SMD. Constellation filed a complaint in the U.S. District Court for the District of Connecticut against Select Energy claiming that Select Energy was responsible for pre- and post-SMD congestion and losses amounting to approximately $9.7 million. Select Energy filed a counterclaim seeking to recover the $2.5 million in pre-SMD charges that Constellation has refused to pay. The case is in the discovery phase with dispositive motions scheduled to filed by the Spring 2005.

6. NRG Bankruptcy

On May 14, 2003, NRG and certain of its affiliates filed for Chapter 11 protection in the United States Bankruptcy Court for the Southern District of New York (Bankruptcy Court). The filing affects relationships between various NU companies and the NRG companies.

A. Station Service

NRG has disputed its responsibility to pay for the provision of station service by CL&P to NRG's Connecticut generating plants. The FERC issued a decision on December 20, 2002 that NRG had agreed that station service from CL&P would be subject to CL&P's applicable retail rates, and that states (i.e., the DPUC) have jurisdiction over the delivery of power to end users even where, as here, power is not delivered via distribution facilities. NRG refused CL&P's subsequent demand for payment, and on April 3, 2003, CL&P petitioned the DPUC for a declaratory order enforcing the FERC's December 20, 2002 decision. Prior to the issuance of a decision by the DPUC, NRG filed a petition under Chapter 11 of the U.S. Bankruptcy Code, staying any further action by the DPUC.

On September 9, 2003, the Bankruptcy Court approved the parties' stipulation to submit the station service issue to arbitration for a determination of liability and damages which will fix CL&P's claim in bankruptcy. The parties are currently pursuing arbitration of the issues in dispute but no hearing dates have been scheduled. On December 17, 2003, the DPUC issued a decision in CL&P's rate case that addressed the issue that CL&P had first raised to the DPUC in its April 3, 2003 filing. The DPUC affirmatively stated that CL&P has been appropriately administering its station service rates. Subsequently, however, in unrelated proceedings, the FERC issued a series of orders with conflicting policy direction, which call into question its December 20, 2002 NRG order.

B. Yankee Gas

On October 9, 2002, NRG informed Yankee Gas that its affiliate, Meriden Gas Turbines, LLC (MGT) was permanently shutting down or abandoning its Meriden power plant project, and requested that Yankee Gas cease its construction activities and begin an orderly wind down of its work relating to the project. Based on NRG's statement that it expected that Yankee Gas would draw on a $16 million LOC, Yankee Gas drew down the full amount of the LOC. On November 12, 2002, MGT filed suit against Yankee Gas in Meriden Superior Court, claiming that Yankee Gas breached the agreement with MGT (MGT Agreement) and seeking a declaratory ruling from the court that Yankee Gas wrongfully drew down the $16 million LOC. In April 2003, Yankee Gas filed its answer to MGT's complaint and asserted several counterclaims to recover its losses arising out of MGT's termination of the MGT Agreement.

Yankee Gas has filed an amended answer and counterclaim and an application for a prejudgment remedy (PJR) seeking to attach sufficient assets to secure a judgment on Yankee Gas' counterclaims and a preliminary injunction seeking to enjoin a sale of MGT's assets, including the MGT project itself. Hearings were held on Yankee Gas' applications and the court ordered the parties to participate in mediation, which was held on September 21, 2004. The mediation was unsuccessful and on October 7, 2004, the court denied Yankee Gas' application for a PJR and preliminary injunction. Expert witness discovery is ongoing. Trial is expected to begin in May 2005.

C. Congestion Charges

On August 5, 2002, CL&P withheld the past due congestion charges from its payment to NRG pursuant to contractual provisions allowing the withholding of disputed sums. CL&P continued to withhold congestion charges from its monthly payments to NRG, through March 1, 2003. On November 28, 2001, CL&P filed a complaint against NRG in Connecticut Superior Court alleging breach of contract arising from the failure of NRG to pay socialized congestion charges. The case was removed to U.S. District Court for the District of Connecticut. NRG filed a counterclaim seeking recovery of all amounts CL&P has withheld. Discovery is complete and CL&P's motion for summary judgment is pending. No trial date is currently scheduled.

For additional information on NRG-related matters, see Item 1, "Business - Rates - Connecticut Retail Rates."

7. Hawkins, Delafield & Wood (Hawkins) v. NU, NUSCO and CL&P

On December 12, 2002, Hawkins, a New York law firm sued by the Connecticut Resources Recovery Authority (CRRA) as a result of the Enron bankruptcy brought an apportionment complaint against a number of former Enron officers, directors and outside accountants. In addition to the Enron defendants, Hawkins also named as defendants in its complaint NU, NUSCO and CL&P. Hawkins asserts in its complaint that in the event it is found liable to CRRA, then the apportionment defendants, including NU, NUSCO and CL&P, are responsible for some or all of the $220 million claimed as damages.

The case is proceeding along three broad tracks: (a) an attempt by various defendants to persuade the Multi-District Litigation (MDL) Judicial Panel to transfer the case to the United States District Court for the Southern District of Texas; (b) an attempt to consolidate this case with a case now pending, which itself is subject to a conditional order of the MDL Judicial Panel transferring it to the Southern District of Texas; and (c) an attempt to remand this case to Connecticut's state court. No further action in this case is anticipated until the MDL Judicial Panel rules, as the United States District Court judge has stayed all proceedings pending such ruling. The NU defendants had not yet responded to the apportionment complaint at the time the proceedings were stayed.

8. Environmental Litigation

On September 25, 2002, NUSCO, among other defendants, was sued by the Joseph A. Schiavone Corporation (Schiavone) under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (Superfund) for the costs associated with the investigation and remediation of a commercial property owned by Schiavone in North Haven, Connecticut. Schiavone alleges that from 1968 through 1978, NUSCO sold transformers containing PCBs to a company named H. Kasden & Sons, a co-defendant, which owned the property before Schiavone and operated a scrap yard at the site. The property is currently involved in an EPA and CDEP monitored investigation and remediation of PCB contamination and related costs are estimated at approximately $4 million. On June 6, 2003, CL&P was added as a defendant.

On December 13, 2004, the U.S. Supreme Court ruled, in an unrelated case, *Cooper Industries Inc. v. Aviall Services Inc.*, that contribution actions under Section 113(f)(1) of Superfund required a prior governmental civil action against the party seeking contribution. This development directly impacted plaintiff's claim against NUSCO/CL&P, since plaintiff had not been subject to a prior governmental civil action. As a direct result, a scheduled January 6, 2005 mediation was cancelled, discovery was suspended, and a Stipulation of Dismissal was filed on January 19, 2005. NUSCO and CL&P are evaluating their options for resolving their dispute with plaintiff in the wake of these events.

9. CYAPC Decommissioning Dispute

A. Bechtel Power Corporation Litigation

On June 13, 2003, CYAPC gave notice of the termination of its contract with Bechtel for the decommissioning of the Connecticut Yankee nuclear power plant, due to Bechtel's history of incomplete and untimely performance and refusal to perform the remaining decommissioning work.

Bechtel has filed a complaint against CYAPC in Connecticut Superior Court. Bechtel's complaint asserts claims for breach of contract, negligent misrepresentation, commercial impracticability, breach of CYAPC's duty of good faith and fair dealing, wrongful termination, and violation of the Connecticut Unfair Trade Practices Act (CUTPA). On August 22, 2003, CYAPC filed its answer and counterclaims, including counts for breach of contract, negligent misrepresentation and breach of duty of good faith and fair dealing. Discovery is ongoing and a trial has been scheduled for May 2006.

On June 18, 2004, Bechtel requested the court to grant a prejudgment remedy in the amount of $93.5 million by garnishing CYAPC's assets, the CYAPC shareholders contributions to the decommissioning trust, and proceeds of DOE litigation.

On October 27, 2004, Bechtel and CYAPC entered into an agreement under which Bechtel relinquished its right to seek garnishment of the decommissioning trusts and related payments, in return for the potential attachment of CYAPC's real property, and an amount totaling $41.7 million (representing shareholder equity) that the sponsors would pay into a separate escrow account through June 30, 2007. CYAPC has continued to contest the attachability of these remaining assets, and the court has not yet ruled on that issue.

On December 3, 2004, Bechtel filed an offer of judgment to settle its claims for a payment of $20 million by CYAPC, conditioned on CYAPC's withdrawal of its counterclaim, which offer was rejected by CYAPC. On February 22, 2005, CYAPC filed an offer of judgment to settle its counterclaims for a payment of $65 million by Bechtel, conditioned on Bechtel's withdrawal of its claims. Bechtel has 60 days to accept or reject the offer. If the offers are rejected, and one of the parties subsequently wins the case in an amount equal to or greater than its offer, the court will add 12 percent annual interest on that award, computed from the date of the party's claim, which is June 23, 2003 in the case of Bechtel's claim, and August 22, 2003 in the case of CYAPC's counterclaim.

B. FERC Proceeding

On July 1, 2004, CYAPC filed with the FERC to increase its decommissioning collections from $16.7 million per year (in 2000 dollars) to $93 million per year (in 2003 dollars) for the six-year period beginning January 1, 2005. The 2003 estimate projects an increase of $395.6 million in 2003 dollars and a total cost to complete decommissioning of $831.3 million in 2003 dollars. The increases largely reflect increased costs of security and insurance, the continuing cost of storing spent nuclear fuel that the DOE has failed to remove, the additional costs to CYAPC for it to manage the decommissioning activities that were Bechtel's responsibilities and declining financial markets.

On August 30, 2004, the FERC issued an order accepting the CYAPC rate filing, suspending collections for five months and establishing hearing procedures. Bechtel was allowed to intervene in the FERC case. The FERC also denied the DPUC/OCC's petition for declaratory order, which had requested that the FERC determine that CYAPC's wholesale purchasers (its utility owners) were responsible for all decommissioning costs, including imprudent costs, but could only pass through to retail ratepayers prudent costs. The FERC held that, under the Federal Power Act, its responsibility was to determine just and reasonable wholesale rates, and not determine retail rates.

On September 29, 2004, the DPUC/OCC sought rehearing of the FERC's August 30 denial of their petition. The rehearing again asks the FERC to enforce the CYAPC owners/purchasers' obligation to pay all decommissioning costs, whether prudent or imprudent. Bechtel also sought clarification of the August 30 order.

A schedule for the FERC trial on the reasonableness of the decommissioning rates has been set by the administrative law judge, with hearings commencing in June 2005 and an initial decision by September 30, 2005.

On October 29, 2004, the FERC issued an order granting for further consideration the requests of DPUC/OCC and Bechtel to rehear FERC's denial of the declaratory petition. The FERC did not set a date by which it would rule on the requests, and it is likely that an order won't be issued until the conclusion of the case. On November 22, 2004, CYAPC filed additional testimony to respond to DPUC/OCC's claims that the Bechtel contract was imprudently managed.

On February 22, 2005, the DPUC and Bechtel each filed testimony with the FERC. The DPUC argues that CYAPC's imprudent management of the decommissioning project while Bechtel was the contractor resulted in schedule delays and cost increases, and recommends a disallowance in the range of about $225 to $234 million. Bechtel claims that it was impossible for it to fulfill its contract obligations, that CYAPC was not justified in terminating its contract and that CYAPC's approach to the remaining decommissioning work is faulty.

Discovery is ongoing and a trial has been tentatively scheduled for 2006. Management cannot predict the outcome of this litigation or its impact on NU.

NU's electric operating subsidiaries collectively own 49.0 percent of CYAPC, as follows: CL&P - 34.5 percent, PSNH - 5.0 percent and WMECO - 9.5 percent.

10. Enron Bankruptcy Claim

On March 31, 2004, CL&P was served with two state court complaints from CRRA (one suit is on behalf of CRRA, the other on behalf of the directors of CRRA) claiming that CL&P either negligently or fraudulently allowed CRRA and its directors to become involved with Enron (collectively, the CRRA Lawsuits). Damages in excess of $200 million are claimed. CL&P has answered the complaints denying all material allegations and is preparing a motion for summary judgment.

On October 14, 2004, CRRA, the Connecticut Attorney General (AG) and CL&P entered into a Settlement Agreement, which resolves all open issues, claims and litigation between CRRA and CL&P arising out of the agreements entered into by the parties on or about December 22, 2000 (the December 22, 2000 Agreements), including the CRRA Lawsuits. If the Settlement Agreement is approved by the Bankruptcy Court, it would also resolve all pending claims between CL&P and Enron arising out of the December 22, 2000 Agreements, except for CL&P's pending claim against Enron Power Marketing Inc. (EPMI) for damages resulting from its rejection of the December 22, 2000 Electricity Purchase Agreement between EPMI and CL&P (rejection damages claim). CL&P's rejection damages claim currently seeks $42.9 million from EPMI.

On December 1, 2004, the DPUC approved the Settlement Agreement, and OCC has waived (in writing) its right to appeal the DPUC's December 1 decision. The settlement was approved by the Bankruptcy Court at a hearing on January 20, 2005 and no appeal was timely filed from the Bankruptcy Court's January 20 decision. Therefore, the settlement became effective on February 1, 2005 and CRRA withdrew with prejudice the remaining CRRA lawsuits on February 7, 2005.

11. Northern Wood Power Project

In August 2003, PSNH sought the approval of the NHPUC to modify one of its older 50 MW coal-fired generating stations, Unit 5 at Schiller Station in Portsmouth (Northern Wood Power Project), to a technologically advanced fluidized bed boiler capable of burning wood, with the plan to burn locally sourced low-grade wood fuel. This project would qualify Schiller Unit 5 to receive revenues from the sale of renewable energy certificates necessary to fulfill renewable portfolio standard requirements in Connecticut and Massachusetts. In May 2004, the NHPUC approved the Northern Wood Power Project and a risk/reward cost-recovery mechanism jointly offered by PSNH, the New Hampshire Governor's Office of Energy and Planning, the New Hampshire Office of Consumer Advocate, and the New Hampshire Timberland Owners' Association. The NHPUC's orders approving this Northern Wood Power Project were appealed to the New Hampshire Supreme Court by four existing wood-fired generating plants located in that state. In their December 2004 Supreme Court brief, the appellant wood-plants claim that there was not sufficient record evidence to demonstrate that the project is in the public interest of PSNH's retail customers; that the NHPUC's orders were administratively deficient; and, that the NHPUC was without authority to approve the risk/reward cost-recovery mechanism. Reply briefs were filed by PSNH, the New Hampshire Attorney General's Office and the Office of Consumer Advocate in January 2005. The New Hampshire Supreme Court heard oral argument on February 16, 2005, and a decision is expected by the end of April 2005.

12. Connecticut MGP Cost Recovery

By letter dated August 5, 2004, Yankee Gas and CL&P (NU Companies) demanded contribution from UGI Utilities, Inc. (UGI) for past and future remediation costs related to MGP operations on thirteen sites currently or formerly owned by the NU Companies in a number of different locations throughout the State of Connecticut. The NU Companies allege that UGI controlled operations of the plants at various times throughout the period 1883 to 1941. According to the NU Companies' demand letter, investigation and remedial costs at the sites to date total approximately $10 million and complete remediation costs for all sites could total $182 million. The NU Companies

are seeking a fair and equitable contribution for these costs from UGI. UGI is reviewing the information provided by the NU Companies and is investigating the claim.

13. Other Legal Proceedings

The following sections of Item 1, "Business" discuss additional legal proceedings: See "Risk Factors" for general information on several significant risks; "Regulated Electric Operations," and "Regulated Gas Operations" for information about various state restructuring and rate proceedings, civil lawsuits related thereto, the implementation of SMD, and information about proceedings relating to power, transmission and pricing issues; "Competitive System Businesses" for information on issues relating to the operation of the merchant energy business, the provision of energy services and related matters; "Nuclear Activities" for information related to high-level and low-level radioactive waste disposal and decommissioning matters; and "Other Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality, toxic substances and hazardous waste, EMF, licensing of hydroelectric projects, and other matters.

Item 4. Submission Of Matters To a Vote of Security Holders

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

Part II

Item 5. Market for The Registrants' Common Equity and Related Stockholder Matters

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

Year	Quarter	High	Low
2004	First	$ 20.10	$ 18.35
	Second	19.50	17.70
	Third	19.49	18.50
	Fourth	20.03	17.30
2003	First	$ 16.06	$ 13.38
	Second	16.77	13.98
	Third	18.28	15.76
	Fourth	20.17	18.12

There were no purchases made by or on behalf of NU or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of common stock during the fourth quarter of the year ended December 31, 2004.

As of January 31, 2005, there were 56,356 common shareholders of record of NU. As of the same date, there were a total of 129,207,462 common shares issued, including 2,584,415 unallocated Employee Stock Ownership Plan (ESOP) shares held in the ESOP trust.

On January 31, 2005 the NU Board of Trustees approved the payment of a 16.25 cent per share dividend, payable on March 31, 2005, to shareholders of record as of March 1, 2005.

On January 12, 2004, the NU Board of Trustees approved the payment of a 15 cent per share dividend, payable on March 31, 2004, to shareholders of record as of March 1, 2004.

On April 13, 2004, the NU Board of Trustees approved the payment of a 15 cent per share dividend, payable on June 30, 2004, to shareholders of record as of June 1, 2004.

On May 10, 2004, the NU Board of Trustees approved the payment of a 16.25 cent per share dividend, payable on September 30, 2004, to shareholders of record as of September 1, 2004.

On October 12, 2004, the NU Board of Trustees approved the payment of a 16.25 cent per share dividend, payable on December 30, 2004, to shareholders of record as of December 1, 2004.

On January 13, 2003, the NU Board of Trustees approved the payment of a 13.75 cent per share dividend, payable on March 31, 2003, to shareholders of record as of March 1, 2003.

On April 8, 2003, the NU Board of Trustees approved the payment of a 13.75 cent per share dividend, payable on June 30, 2003, to shareholders of record as of June 1, 2003.

On May 13, 2003, the NU Board of Trustees approved the payment of a 15 cent per share dividend, payable on September 30, 2003, to shareholders of record as of September 1, 2003.

On October 14, 2003, the NU Board of Trustees approved the payment of a 15 cent per share dividend, payable on December, 2003, to shareholders of record as of December 1, 2003.

Information with respect to dividend restrictions for NU and its subsidiaries is contained in Item 1. Business under the caption "Financing Program - Financing Limitations" and in Note A to the "Consolidated Statements of Shareholders' Equity" within NU's 2004 Annual Report to Shareholders, which information is incorporated herein by reference.

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

During 2004 and 2003, CL&P approved and paid $47.1 million and $60.1 million of common stock dividends to NU.

During 2004 and 2003, PSNH approved and paid $27.2 million and $16.8 million of common stock dividends, respectively, to NU.

During 2004 and 2003, WMECO approved and paid approximately $6.5 million and $22 million of common stock dividends, respectively, to NU.

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

Item 6. Selected Financial Data

NU. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within NU's 2004 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within CL&P's 2004 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within PSNH's 2004 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Selected Consolidated Financial Data" contained within WMECO's 2004 Annual Report, which information is incorporated herein by reference.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

NU. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within NU's 2004 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within CL&P's 2004 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within PSNH's 2004 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Management's Discussion and Analysis and Results of Operations" contained within WMECO's 2004 Annual Report, which information is incorporated herein by reference.

Item 7a. Quantitative and Qualitative Disclosures about Market Risk

Market Risk Information

Select Energy utilizes the sensitivity analysis methodology to disclose quantitative information for its commodity price risks. Sensitivity analysis provides a presentation of the potential loss of future earnings, fair values or cash flows from market risk-sensitive instruments over a selected time period due to one or more hypothetical changes in commodity prices, or other similar price changes. Under sensitivity analysis, the fair value of the portfolio is a function of the underlying commodity, contract prices and market prices represented by each derivative commodity contract. For swaps, forward contracts and options, fair value reflects management's best estimates considering over-the-counter quotations, time value and volatility factors of the underlying commitments. Exchange- traded futures and options are recorded at fair value based on closing exchange prices.

NU Enterprises - Wholesale and Retail Marketing Portfolio: When conducting sensitivity analyses of the change in the fair value of Select Energy's electricity, natural gas and oil on the wholesale and retail marketing portfolio, which would result from a hypothetical change in the future market price of electricity, natural gas and oil, the fair values of the contracts are determined from models that take into consideration estimated future market prices of electricity, natural gas and oil, the volatility of the market prices in each period, as well as the time value factors of the underlying commitments. In most instances, market prices and volatility are determined from quoted prices on the futures exchange.

Select Energy has determined a hypothetical change in the fair value for its wholesale and retail marketing portfolio, which includes cash flow hedges and electricity, natural gas and oil contracts, assuming a 10 percent change in forward market prices. At December 31, 2004, a 10 percent change in market price would have resulted in an increase in fair value of $25.6 million or a decrease in fair value of $23.6 million.

The impact of a change in electricity, natural gas and oil prices on Select Energy's wholesale and retail marketing portfolio at December 31, 2004, is not necessarily representative of the results that will be realized when these contracts are physically delivered.

NU Enterprises - Trading Contracts: At December 31, 2004, Select Energy has calculated the market price resulting from a 10 percent change in forward market prices. That 10 percent change would result in approximately a $1.0 million increase or decrease in the fair value of the Select Energy trading portfolio. In the normal course of business, Select Energy also faces risks that are either non-financial or non-quantifiable. These risks principally include credit risk, which is not reflected in this sensitivity analysis

Other Risk Management Activities

Interest Rate Risk Management: NU manages its interest rate risk exposure in accordance with its written policies and procedures by maintaining a mix of fixed and variable rate debt. At December 31, 2004, approximately 86 percent (76 percent including the debt subject to the fixed-to-floating interest rate swap in variable rate debt) of NU's long-term debt, including fees and interest due for spent nuclear fuel disposal costs, is at a fixed interest rate. The remaining long-term debt is variable-rate and is subject to interest rate risk that could result in earnings volatility. Assuming a one percentage point increase in NU's variable interest rates, including the rate on debt subject to the fixed-to-floating interest rate swap, annual interest expense would have increased by $3.9 million. At December 31, 2004, NU parent maintained a fixed-to-floating interest rate swap to manage the interest rate risk associated with its $263 million of fixed-rate debt.

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

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

NU tracks and re-balances the risk in its portfolio in accordance with fair value and other risk management methodologies that utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

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

At December 31, 2004 and December 31, 2003, Select Energy maintained collateral balances from counterparties of $57.7 million and $46.5 million, respectively. These amounts are included in both cash and cash equivalents and other current liabilities on the accompanying consolidated balance sheets. Select Energy also has collateral balances deposited with counterparties of $46.3 million and $17 million at December 31, 2004 and December 31, 2003, respectively.

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

Additional quantitative and qualitative disclosures about market risk are set forth in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," to the consolidated financial statements herein.

Item 8. Financial Statements and Supplementary Data

NU. Reference is made to information under the headings "Independent Auditors' Report," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Shareholders' Equity," "Consolidated Statements of Cash Flows," "Consolidated Statements of Capitalization," "Notes to Consolidated Financial Statements," and "Consolidated Statements of Quarterly Financial Data" contained within NU's 2004 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the headings "Independent Auditors' Report," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within CL&P's 2004 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the headings "Independent Auditors' Report," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within PSNH's 2004 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the headings "Independent Auditors' Report," "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Statements of Common Stockholder's Equity," "Consolidated Statements of Cash Flows," "Notes to Consolidated Financial Statements," and "Consolidated Quarterly Financial Data" contained within WMECO's 2004 Annual Report, which information is incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

No events that would be described in response to this item have occurred with respect to NU, CL&P, PSNH or WMECO.

Item 9a. Controls and Procedures

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of NU and subsidiaries and of other sections of this annual report. These financial statements, which were audited by Deloitte & Touche LLP, have been prepared in conformity with accounting principles generally accepted in the United States of America using estimates and judgments, where required, and giving consideration to materiality.

Additionally, management is responsible for establishing and maintaining adequate internal controls over financial reporting. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, NU conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal controls over financial reporting was ineffective as of December 31, 2004. Management identified a material weakness due to deficiencies in both the design and operating effectiveness of internal controls associated with the application of derivative accounting rules to certain wholesale natural gas contracts entered into by the wholesale marketing portion of NU Enterprises' merchant energy segment. NU filed a Form 8-K on January 26, 2005 to provide notice of the restatement of June 30, 2004 and September 30, 2004 reports on Form 10-Q due to this accounting error. Restatements amounted to an increase in net income of $1.1 million for the quarter ended June 30, 2004 and a decrease in net income of $47 million for the quarter ended September 30, 2004. Numerous account balances were affected by these material misstatements, primarily fuel, purchased and net interchange power, income tax expense, derivative assets, derivative liabilities, retained earnings, and accumulated other comprehensive income.

Accounting for derivative contracts is complex and requires a significant amount of judgment and interpretation of the rules. During the second and third quarters of 2004, management accounted for certain wholesale natural gas contracts using the accrual method of accounting. Using this method, changes in the fair value of the derivative contracts did not impact net income currently. As a result of further analysis performed through January 2005, management concluded that an error had been made in interpreting the derivative accounting rules. This misinterpretation led to a misapplication of the derivative accounting rules. These wholesale natural gas contracts should have been recorded at fair value with changes in fair value reflected currently in net income. The restatements discussed above were required in order to apply fair value accounting to these contracts. The material weakness occurred due to deficiencies in both the design and operating effectiveness of the internal control environment.

Management identified and is strengthening the effectiveness and design of internal controls related to this matter. During the first quarter of 2005, management is enhancing the effectiveness of internal controls by requiring additional documentation for each wholesale derivative transaction accounted for on an accrual basis. Management is also enhancing the design of internal controls as

follows. Accounting management will review and approve the accounting for all material transactions requiring accounting judgments. Accounting reporting relationships will be enhanced by having business unit controllers report to the corporate controller for accounting and financial reporting matters.

These control enhancements are being implemented in the first quarter of 2005. As a result, material misstatements in account balances and related disclosures associated with this material weakness are not expected in the future. However, until these controls or control enhancements are concluded to be operating effectively, management cannot determine if the material weakness described above will be eliminated.

This material weakness was discussed with the Audit Committee of the Board of Trustees and Deloitte & Touche LLP, our independent registered public accounting firm. Deloitte & Touche LLP, has issued an attestation report on management's assessment of internal controls over financial reporting.

NU undertook, in a separate evaluation, of the design and operation of their disclosure controls and procedures to determine whether they are effective in ensuring that the disclosure of required information is made timely and in accordance with the Exchange Act and the rules and forms of the SEC. This evaluation was made under the supervision and with the participation of management, including NU's principal executive officer and principal financial officer, as of the end of the period covered by this Annual Report on Form 10-K. The principal executive officer and principal financial officer have concluded, based on their review, that NU's disclosure controls and procedures are ineffective, solely related to the material weakness described above, to ensure that information required to be disclosed by the companies in reports that it files under the Exchange Act i) is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and ii) is accumulated and communicated to management including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

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

There have been no significant changes in internal controls over financial reporting during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect internal controls over financial reporting.

Item 9b. Other Information

No information is required to be disclosed under Item 9b at December 31, 2004, as this information has been previously disclosed in applicable reports on Form 8-K during the fourth quarter of 2004.

PART III

Item 10. Directors and Executive Officers of The Registrants

The information in Item 10 is provided as of March 1, 2005 except where otherwise indicated.

NU.

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information contained in the sections "Proxy Statement - Election of Trustees," "Board Committees and Responsibilities," "Selection of Trustees," and "Section 16(a) Beneficial Ownership Reporting Compliance," of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2005, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

Name	Positions Held
Gregory B. Butler (1)	SVP, SEC, GC
Lawrence E. De Simone (2)	P
John H. Forsgren (3)	EVP, CFO, VC, T
Cheryl W. Grisé (1)	P
David R. McHale (4)	SVP, CFO
Leon J. Olivier (5)	P
Charles W. Shivery (1)	CHB, P, CEO, T

CL&P

Name	Positions Held
David H. Boguslawski (7)	D, VP
Gregory B. Butler (1)	OTH
John H. Forsgren (3)	EVP, CFO
Cheryl W. Grisé (1)	CEO, D
David R. McHale (4)	SVP, CFO
Raymond P. Necci (6)	P, COO, D
Leon J. Olivier (5)	OTH, D
Charles W. Shivery (1)	OTH

PSNH

Name	Positions Held
David H. Boguslawski (7)	D, VP
Gregory B. Butler (1)	OTH
John H. Forsgren (3)	EVP, CFO, D
Cheryl W. Grisé (1)	CEO, D
Gary A. Long (1)	P, COO, D
David R. McHale (4)	SVP, CFO, D
Leon J. Olivier (5)	OTH, D
Charles W. Shivery (1)	OTH

WMECO.

Name	Positions Held
David H. Boguslawski (7)	D, VP
Gregory B. Butler (1)	OTH
John H. Forsgren (3)	EVP, CFO, D
Cheryl W. Grisé (1)	CEO, D
Kerry J. Kuhlman (8)	P, D
David R. McHale (4)	SVP, CFO, D
Leon J. Olivier (5)	OTH, D
Rodney O. Powell (1)	P, COO, D
Charles W. Shivery (1)	OTH

(1) Executive Officer.
(2) Became an executive officer of NU upon election as President-Competitive Group effective October 25, 2004.
(3) Retired as of the end of 2004.
(4) Became an executive officer upon election as Senior Vice President and Chief Financial Officer effective January 1, 2005.
(5) Became an executive officer upon election as President-Transmission Group of NU effective January 17, 2005. Elected Director of WMECO & PSNH on January 17, 2005.
(6) Became an executive officer of CL&P upon election as President and Chief Operating Officer, effective January 17, 2005. Also elected a Director of CL&P, effective January 17, 2005.
(7) Resigned as Director, effective January 16, 2005.
(8) President and Director through December 31, 2004.

Key:

CEO	-	Chief Executive Officer
CFO	-	Chief Financial Officer
CHB	-	Chairman of the Board
COO	-	Chief Operating Officer
D	-	Director
EVP	-	Executive Vice President
GC	-	General Counsel
OTH	-	Executive Officer of Registrant because of policy-making function for NU System
P	-	President
SEC	-	Secretary
SVP	-	Senior Vice President
T	-	Trustee
VP	-	Vice President
VC	-	Vice Chairman

Name	Age	Business Experience During Past 5 Years
David H. Boguslawski	50	Vice President – Transmission Strategy and Operations since January 17, 2005; previously Vice President - Transmission Business of CL&P, PSNH and WMECO from May 1, 2001 to January 16, 2005 and a Director of CL&P, PSNH and WMECO from June 30, 1999 to January 16, 2005; previously Vice President - Energy Delivery of CL&P, PSNH and WMECO from September 1996 to May 2001.
Gregory B. Butler	47	Senior Vice President, Secretary and General Counsel of NU since August 31, 2003 and a Director of Northeast Utilities Foundation, Inc. since December 1, 2002; previously Vice President, Secretary and General Counsel of NU from May 1, 2001 through August 30, 2003; Vice President - Governmental Affairs of NUSCO from January 1997 to May 2001.
Lawrence E. De Simone	57	President-Competitive Group of NU and President of NU Enterprises, Inc., since October 25, 2004 and President of Select Energy, Inc, since February 1, 2005; previously Executive Vice President - Regulated Business and Services of PPL Corporation from January 1, 2004 to August 31, 2004; Executive Vice President - Supply of PPL Corporation from October 2001 to December 31, 2003; and President of PPL EnergyPlus from November 1, 1998 to September 30, 2001.
John H. Forsgren (*)	58	Retired as of the end of 2004; previously Vice Chairman of NU from May 1, 2001 to December 31, 2004; Executive Vice President and Chief Financial Officer of NU from February 1, 1996 to December 31, 2004; Executive Vice President and Chief Financial Officer of CL&P, PSNH, and WMECO from February 27, 2003 to December 31, 2004 and from February 1996 to June 1999; Director of WMECO from June 10, 1996 to December 31, 2004 and of PSNH from August 5, 1996 to December 31, 2004 and a Director of Northeast Utilities Foundation, Inc. from September 23, 1998 to December 31, 2004; Director of CL&P from June 1996 to June 1999.
Cheryl W. Grisé (**)	52	President – Utility Group of NU since May 2001, Chief Executive Officer of CL&P, PSNH and WMECO since September 10, 2002, a Director of CL&P since May 1, 2001, PSNH since May 14, 2001 and WMECO since June 2001, and a Director of Northeast Utilities Foundation, Inc. since September 23, 1998; previously President of CL&P from May 2001 to September 2001, Senior Vice President, Secretary and General Counsel of NU from July 1998 to May 2001, Senior Vice President, Secretary and General Counsel of CL&P and PSNH and Senior Vice President, Secretary, Assistant Clerk and General Counsel of WMECO from July 1998 to June 1999 and Senior Vice President, Secretary and General Counsel of NGC from January 1999 to June 1999; previously Director of CL&P and WMECO (January 1994 through November 1997) and PSNH (February 1995 through November 1997); Senior Vice President and Chief Administrative Officer of CL&P and PSNH, and Senior Vice President of WMECO from 1995 to 1998.
Kerry J. Kuhlman	54	President and Chief Operating Officer and a Director of WMECO from April 1999 through December 31, 2004; previously Vice President-Customer Operations of WMECO from October 1998 to April 1999; Vice President-Central Region of CL&P from August 1997 to October 1998; and Vice President-Eastern Region of CL&P from July 1994 to August 1997.
Gary A. Long (***)	53	President and Chief Operating Officer and a Director of PSNH since July 1, 2000; previously Senior Vice President - PSNH of PSNH from February 2000 through June 2000 and Vice President - Customer Service and Economic Development of PSNH from January 1994 to February 2000.
David R. McHale	44	Senior Vice President and Chief Financial Officer of NU, CL&P, WMECO and PSNH since January 1, 2005 and a Director of WMECO and PSNH since January 1, 2005; previously Vice President and Treasurer of NU, WMECO and PSNH since July 1998.

Raymond P. Necci	53	President and Chief Operating Officer and a Director of CL&P since January 1, 2005. Previously Vice President - Utility Group Services of NUSCO from January 1, 2002 to January 16, 2005; Vice President - Nuclear Operations of Dominion Nuclear Connecticut from March 31, 2001 to December 31, 2001; and Vice President - Nuclear Technical Services of Northeast Nuclear Energy Company from December 15, 1999 to March 31, 2001.
Leon J. Olivier	56	President - Transmission Group of NU and a Director of WMECO and PSNH since January 17, 2005 and a Director of CL&P since September 2001. Previously, President and Chief Operating Officer of CL&P from September 2001 to January 2005; previously Senior Vice President of Entergy Nuclear Corp. from April 2001 to September 2001; Senior Vice President and Chief Nuclear Officer of Northeast Nuclear Energy Company from October 1998 to May 2001.
Rodney O. Powell	52	President and a Director of WMECO since January 1, 2005. Previously Vice President - Customer Relations of CL&P from January 1, 2002 to December 31, 2004; Vice President - Central Region of CL&P from October 14, 1998 to January 1, 2002; and a Director of CL&P from June 30, 1999 to September 10, 2001.
Charles W. Shivery (****)	59	Chairman of the Board, President and Chief Executive Officer of NU since March 29, 2004; Previously, President (interim) of NU from January 1, 2004 to March 29, 2004 and a Director of Northeast Utilities Foundation since March 3, 2004; previously President - Competitive Group of NU and President and Chief Executive Officer of NU Enterprises, Inc., from June 2002 through December 31, 2003; Co-President of Constellation Energy Group, Inc. from October 2000 to February 2002; President and Chief Executive Officer of Constellation Power Source Holdings, Inc., from July 2000 to February 2002; Chief Executive Officer and President of Constellation Enterprises, Inc. from 1998 to February 2002; and Chairman of the Board, President and Chief Executive Officer of Constellation Power Source, Inc., from 1997 to February 2002.

(*) Mr. Forsgren is a Director of NEON Communications, Inc. and CuraGen Corporation.
(**) Mrs. Grisé is a Director of MetLife, Inc. and Dana Corporation.
(***) Mr. Long is a Director of Citizens Bank-NH.
(****) Mr. Shivery is a Director of Energy Insurance Mutual, the Connecticut Business & Industry Association and Connecticut Children's Hospital.

There are no family relationships between any director or executive officer and any other director or executive officer of NU, CL&P, PSNH or WMECO.

NU, CL&P, PSNH, WMECO

Each of the registrants has adopted a Code of Ethics for Senior Financial Officers (Chief Executive Officer, Chief Financial Officer and Controller). The Code of Ethics has been posted on Northeast Utilities' web site and is available at http://www.nu.com/investors/corporate_gov/default.asp on the Internet. Information pertaining to amendments and waivers from the Code of Ethics will be posted at this site.

Printed copies of the Code of Ethics are also available to any shareholder without charge upon written request mailed to:

Mr. Gregory B. Butler, Senior Vice President,
Secretary and General Counsel
Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06414

Item 11. Executive Compensation

NU

Incorporated herein by reference is the information contained in the sections "Executive Compensation," "Long-Term Incentive Plans -Awards in Last Fiscal Year," "Pension Benefits," "Trustee Compensation," "Employment Contracts and Termination of Employment and Change in Control Arrangements," "Compensation Committee Report on Executive Compensation" and "Share Performance Chart" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2005, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

CL&P, PSNH, WMECO

SUMMARY COMPENSATION TABLE

The following tables present the cash and non-cash compensation received by the Chief Executive Officer and the next four highest paid executive officers of CL&P, PSNH, and WMECO in accordance with rules of the Securities and Exchange Commission (SEC):

		Annual Compensation			Long-Term Compensation Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($) (Note 1)	Restricted Stock Award(s) ($) (Note 2)	Securities Underlying Options/Stock Appreciation Rights (#)	Long-Term Incentive Program Payouts ($)	All Other Compensation ($) (Note 3)
Charles W. Shivery	2004	799,380	200,000	3,754	866,244	-	-	43,150
Chairman of the	2003	554,616	674,000	8,946	220,004	-	-	16,639
Board, President	2002	306,731	200,000	224,594	-	29,204	-	7,615
and Chief Executive Officer of NU (Note 5)								
John H. Forsgren	2004	589,616	-	8,700	444,595	-	-	214,284
Vice Chairman of	2003	574,615	1,086,175	17,384	427,495	-	-	187,574
NU, Executive Vice	2002	556,154	165,000	-	-	54,400	-	179,674
President and Chief Financial Officer of NU, PSNH and WMECO (Note 4)								
Cheryl W. Grisé	2004	505,539	234,949	5,000	387,494	-	-	229,321
President - Utility	2003	451,538	581,513	13,216	324,994	-	-	184,587
Group of NU and	2002	409,231	280,000	-	-	39,600	-	180,523
Chief Executive Officer of CL&P, PSNH and WMECO								
Gregory B. Butler	2004	304,615	75,316	760	250,003	-		12,785
Senior Vice	2003	244,615	232,200	4,473	109,995	-	-	6,000
President, Secretary	2002	206,154	70,000	-	-	13,200	-	6,000
and General Counsel of NU and NUSCO								
Leon J. Olivier	2004	330,693	143,521	107,993	81,696	-	-	12,523
President and Chief	2003	317,100	275,000	3,192	78,505	-	-	18,343
Operating Officer	2002	303,908	138,000	-	-	9,900	-	9,117
of CL&P (Note 6) (CL&P Table Only)								
Gary A. Long	2004	193,077	79,308	-	66,509	-	-	7,947
President and Chief	2003	185,154	140,000	2,.643	65,002	-	-	5,555
Operating Officer	2002	178,154	70,000	-	-	8,100	-	5,345
of PSNH (PSNH Table Only)								
Kerry J. Kuhlman	2004	187,000	63,879	-	64,704	-	-	7,682
President and Chief	2003	180,015	125,000	2,542	62,499	-	-	5,400
Operating Officer	2002	173,093	62,000	-	-	7,900	-	5,193
of WMECO (Note 7) (WMECO Table Only)								

Notes:

(1) "Other Annual Compensation" for Mr. Shivery includes $144,000 of relocation expenses in 2002, per his employment agreement. "Other Annual Compensation" for Mr. Olivier includes $105,966 of supplemental pension payments payable under his previous employment agreement with Northeast Nuclear Energy Company, an affiliate of CL&P. "Other Annual Compensation" for other officers includes miscellaneous items such as reimbursement for financial planning fees.

(2) Restricted shares listed in the Table are valued as of the date of grant. The aggregate restricted share holdings by the individuals named in the table were, at December 31, 2004, 252,761 common shares, with an aggregate value of $4,764,545. The aggregate restricted share holdings by each of the individuals named in the table and the value thereof, at December 31, 2004, were 67,667 common shares ($1,275,711) for Mr. Shivery; 81,495 common shares ($1,536,181) for Mr. Forsgren; 61,926 common shares ($1,167,305) for Mrs. Grisé; 19,289 common shares ($363,598) for Mr. Butler; 8,560 common shares ($161,356) for Mr. Olivier; 7,027 common shares ($132,459) for Mr. Long and 6,797 common shares ($128,123) for Mrs. Kuhlman. Each of the individuals were awarded restricted share units as long term incentive compensation during 2004, which vest over four years, with 50% payable at vesting and 50% payable 4 years after vesting; dividends on restricted share units are reinvested and additional shares added as a result of reinvestment are vested and paid on the same schedule. In addition, Mr. Shivery was awarded 25,000 restricted shares in 2004 upon his appointment as Chairman, President and CEO; these shares vest over 4 years and dividends are paid out during the vesting period. In 2003, certain individuals were awarded restricted shares as long term compensation which vest over four years; dividends on these restricted shares are paid out during the vesting period. Payment of 50% of the 2003 annual incentive payout for Mr. Shivery, Mr. Forsgren and Mrs. Grisé was made in restricted share units which vest over three years and on which dividends are reinvested during the vesting period. Payment of 50 percent of the 2001 and 2002 annual bonuses of each of Mr. Forsgren and Mrs. Grisé was made on February 25, 2002 and February 25, 2003, respectively, in the form of restricted shares vesting one-third on each of the next three anniversaries of these payments; dividends on these restricted shares granted in 2003 are paid out during the vesting period.

(3) "All Other Compensation" for 2004 consists of employer matching contributions under the Northeast Utilities Service Company 401k Plan, generally available to all eligible employees ($6,150 for each named officer other than Mr. Forsgren - $0, Mr. Long - $5,792 and Mrs. Kuhlman - $5,610), matching contributions under the Deferred Compensation Plan for Executives (Mr. Shivery - $17,831, Mrs. Grisé - $9,016, Mr. Butler - $2,988 and Mr. Olivier - $3,771) and dividends on restricted stock (Mr. Shivery - $19,169, Mr. Forsgren - $14,172, Mrs. Grisé - $10,774, Mr. Butler - $3,647, Mr. Olivier - $2,603. Mr. Long - $2,155 and Mrs. Kuhlman - $2,072). For Mr. Forsgren and Mrs. Grisé, it also includes vested deferred compensation paid out in 2004 of $200,112 and $203,381, respectively (See Employment Contracts and Termination of Employment and Change in Control Arrangements, below).

(4) Retired December 31, 2004.

(5) Served as interim President effective January 1, 2004 and elected Chairman of the Board, President and Chief Executive Officer on March 29, 2004.

(6) Mr. Olivier served as President of CL&P through January 17, 2005.

(7) Mrs. Kuhlman served as President of WMECO through December 31, 2004.

Aggregated Options/SAR Exercises in Last Fiscal Year and FY-End Option/SAR Values

Name	Shares With Respect to Which Options Were Exercised #)	Value Realized ($)	Number of Securities Underlying Unexercised Options/SARs at Fiscal Year End (#)		Value of Unexercised In-the-Money Options/SARs at Fiscal Year End ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Charles W. Shivery	-	-	19,349	9,675	-	-
John H. Forsgren	-	-	134,266	18,134	9,792	4,896
Cheryl W. Grisé	-	-	158,027	13,201	126,513	3,564
Gregory J. Butler	-	-	24,400	4,400	6,089	1,188
Leon J. Olivier (CL&P)	-	-	16,599	3,301	1,782	891
Gary A. Long (PSNH)	-	-	25,349	2,701	26,409	729
Kerry J. Kuhlman (WMECO)	-	-	26,230	2,634	28,596	711

LONG-TERM INCENTIVE PLANS – AWARDS IN LAST FISCAL YEAR

Grants of three-year performance units were made during 2004 under the Northeast Utilities Incentive Plan to the Company's officers. Payments will be made in cash following the close of the performance period. Threshold, target, and maximum payouts will be determined based on net income over the performance period. In the event of termination due to retirement, death, or disability, grants are prorated based on time in the performance period and their value shall be determined based on performance through the end of the performance period. In the event of a Change of Control, as defined, grants are prorated based on time in the performance period, their value shall be set at target, and their value shall be paid immediately. In the event of a Termination Upon a Change of Control, as defined, grants are fully vested, their value shall be set at target, and their value shall be paid immediately. Grants to the executive officers named in the Summary Compensation Table were as follows:

			Estimated Future Payouts Under Non-stock Price-Based Plans		
(a)	(b)	(c)	(d)	(e)	(f)
Name	Number of Shares, Units or Other Rights (#)	Performance or Other Period Until Maturation or Payout	Threshold ($)	Target ($)	Maximum ($)
Charles W. Shivery	4,000	1/1/2004-12/31/2006	160,000	400,000	560,000
John H. Forsgren	4,446	1/1/2004-12/31/2006	177,840	444,600	622,440
Cheryl W. Grisé	3,875	1/1/2004-12/31/2006	155,000	387,500	542,500
Gregory B. Butler	2,500	1/1/2004-12/31/2006	100,000	250,000	350,000
Leon J. Olivier (CL&P)	818	1/1/2004-12/31/2006	32,720	81,800	114,520
Gary A. Long (PSNH)	665	1/1/2004-12/31/2006	26,600	66,500	93,100
Kerry J. Kuhlman (WMECO)	648	1/1/2004-12/31/2006	25,920	64,800	90,720

PENSION BENEFITS

The tables on the following pages show the estimated annual retirement benefits payable to an executive officer of CL&P, PSNH or WMECO upon retirement, assuming that retirement occurs at age 65 and that the officer is at that time not only eligible for a pension benefit under the Northeast Utilities Service Company Retirement Plan (the Retirement Plan) but also eligible for either the make-whole benefit or the make-whole benefit plus the target benefit under the Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies (the Supplemental Plan). The Supplemental Plan is a non-qualified pension plan providing supplemental retirement income to system officers. The make-whole benefit under the Supplemental Plan, available to all officers, makes up for benefits lost through application of certain tax code limitations on the benefits that may be provided under the Retirement Plan, and includes as "compensation" awards under the executive incentive plans and deferred compensation (as earned). The target benefit further supplements these benefits and is available to officers at the Senior Vice President level and higher who are selected by the Board of Trustees to participate in the target benefit and who remain in the employ of Northeast Utilities companies until at least age 60 (unless the Board of Trustees sets an earlier age).

Messrs. Shivery and Butler and Mrs. Grisé are currently eligible for a make-whole plus a target benefit and Mr. Forsgren, having retired at the end of 2004, is currently receiving such benefit. Messrs. Olivier and Long and Mrs. Kuhlman are eligible for the make-whole benefit but not the target benefit.

Mr. Shivery's employment agreement provides for a special retirement benefit, following completion of five years of service with the Company (2007), consisting of the excess over benefits otherwise payable from the Retirement Plan and the Supplemental Plan needed to give him the equivalent of fully-vested benefits under the Retirement Plan and the Supplemental Plan calculated by adding three additional years to his actual service and utilizing an early commencement reduction factor of 2 percent per year for each year younger than age 65 at commencement, if better than the factors then in use under the Retirement Plan.

Mr. Forsgren's employment agreement provides for supplemental pension benefits based on crediting additional service for the make-whole plus target benefit under the Supplemental Plan. Based on his age and service at retirement, Mr. Forsgren is eligible for a make-whole plus target benefit based on crediting 11.9 extra years of service, unreduced for early commencement. Mr. Forsgren's employment agreement also provides for payments equal to 25 percent of final average compensation (not to exceed 170 percent of highest average base compensation received in any 36 month period) for up to 15 years following retirement, reduced by four percentage points for each year that his age is less than 65 years at retirement. Because Mr. Forsgren retired at the end of 2004 at the age of 58 years and 4 months, the amount of supplemental 15-year annuity benefit provided will equal 18.3% of his final average compensation, which includes an average incentive of 70% of base pay. Also, as a result of his retirement, Mr. Forsgren's 2003 restricted shares issued under the Long-Term Incentive Program were vested on a pro rata basis, so that 6,398 restricted shares with a value of $120,602 as of December 31, 2004, became immediately vested.

The terms of Mr. Olivier's employment provide for certain supplemental pension benefits in lieu of a make-whole benefit if certain eligibility requirements are met, in order to provide a benefit similar to that provided by his previous employer. If Mr. Olivier remains in continuous employment with the Company until September 10, 2011 (or earlier with the Company's permission), he will be eligible for a special benefit, subject to reduction for termination prior to age 65, of three percent of Final Average Compensation for each of his first 15 years of service since September 10, 2001 plus one percent of Final Average Compensation for each of the second 15 years of service. Alternatively, if he does not voluntarily terminate his employment with the Company prior to his 60th birthday, or upon earlier termination upon a Change of Control, as defined in the Special Severance Program, he may receive upon retirement a lump sum payment of $2,050,000 in lieu of the make-whole benefit and the benefit described in the preceding sentence. These supplemental pension benefits will be offset by the value of any benefits he receives from the Retirement Plan.

ANNUAL BENEFIT FOR OFFICERS ELIGIBLE FOR MAKE-WHOLE BENEFIT

Final Average Compensation	Years of Credited Service				
	15	20	25	30	35
$200,000	$43,174	$57,565	$71,957	$86,591	$101,226
$250,000	$54,424	$72,565	$90,707	$109,091	$127,476
$300,000	$65,674	$87,565	$109,457	$131,591	$153,726
$350,000	$76,924	$102,565	$128,207	$154,091	$179,976
$400,000	$88,174	$117,565	$146,957	$176,591	$206,226
$450,000	$99,424	$132,565	$165,707	$199,091	$232,476
$500,000	$110,674	$147,565	$184,457	$221,591	$258,726
$600,000	$133,174	$177,565	$221,957	$266,591	$311,226
$700,000	$155,674	$207,565	$259,457	$311,591	$363,726
$800,000	$178,174	$237,565	$296,957	$356,591	$416,226
$900,000	$200,674	$267,565	$334,457	$401,591	$468,726
$1,000,000	$223,174	$297,565	$371,957	$446,591	$521,226
$1,100,000	$245,674	$327,565	$409,457	$491,591	$573,726
$1,200,000	$268,174	$357,565	$446,957	$536,591	$626,226
$1,300,000	$290,674	$387,565	$484,457	$581,591	$678,726
$1,400,000	$313,174	$417,565	$521,957	$626,591	$731,226
$1,500,000	$335,674	$447,565	$559,457	$671,591	$783,726

ANNUAL BENEFIT FOR OFFICERS ELIGIBLE FOR
TARGET PLUS MAKE WHOLE BENEFIT

Final Average Compensation	Years of Credited Service				
	15	20	25	30	35
$ 200,000	$ 72,000	$ 96,000	$ 120,000	$ 120,000	$ 120,000
250,000	90,000	120,000	150,000	150,000	150,000
300,000	108,000	144,000	180,000	180,000	180,000
350,000	126,000	168,000	210,000	210,000	210,000
400,000	144,000	192,000	240,000	240,000	240,000
450,000	162,000	216,000	270,000	270,000	270,000
500,000	180,000	240,000	300,000	300,000	300,000
600,000	216,000	288,000	360,000	360,000	360,000
700,000	252,000	336,000	420,000	420,000	420,000
800,000	288,000	384,000	480,000	480,000	480,000
900,000	324,000	432,000	540,000	540,000	540,000
1,000,000	360,000	480,000	600,000	600,000	600,000
1,100,000	396,000	528,000	660,000	660,000	660,000
1,200,000	432,000	576,000	720,000	720,000	720,000
1,300,000	468,000	624,000	780,000	780,000	780,000
1,400,000	504,000	672,000	840,000	840,000	840,000
1,500,000	540,000	720,000	900,000	900,000	900,000
1,600,000	576,000	768,000	960,000	960,000	960,000
1,700,000	612,000	816,000	1,020,000	1,020,000	1,020,000

The benefits presented in the tables above are based on a straight life annuity beginning at age 65 and do not take into account any reduction for joint and survivorship annuity payments. Final average compensation for purposes of calculating the target benefit is the highest average annual compensation of the participant during any 36 consecutive months compensation was earned. Final average compensation for purposes of calculating the make-whole benefit is the highest average annual compensation of the participant during any 60 consecutive months compensation was earned. Compensation for these benefits includes the annual salary and bonus shown in the Summary Compensation Table and, for the make-whole benefit for officers hired before November 1, 2001, and for the target benefit for officers who were hired before November 1, 2001 and eligible for the target benefit prior to October 2003, an amount that represents the annual value of long-term incentive compensation. Compensation for purposes of these benefits does not include employer matching contributions under the 401k Plan. In the event that an officer's employment terminates because of disability, the retirement benefits shown above would be offset by the amount of any disability benefits payable to the recipient that are attributable to contributions made by Northeast Utilities and its subsidiaries under long-term disability plans and policies.

The compensation covered by the Supplemental Plan in 2004 for Mr. Shivery, Mr. Forsgren, Mrs. Grisé, Mr. Butler, Mr. Olivier, Mr. Long, and Mrs. Kuhlman was $999,380, $861,803, $877,038, $379,931, $516,741, $295,236 and $274,097, respectively.

As of December 31, 2004, the executive officers named in the Summary Compensation Table had attained the following years of credited service for purposes of the Supplemental Plan: Mr. Shivery – 2, Mr. Forsgren – 8, Mrs. Grisé – 24, Mr. Butler - 8, Mr. Olivier - 5, Mr. Long - 29, and Mrs. Kuhlman - 23. Mr. Forsgren had 20 years of service for purposes of his supplemental pension benefit.

EMPLOYMENT CONTRACTS AND TERMINATION OF EMPLOYMENT ARRANGEMENTS

NUSCO has entered into employment agreements or arrangements with Messrs. Shivery, Butler, Forsgren and Olivier and Mrs. Grisé; Mr. Olivier and each of the other named executive officers participate in the Special Severance Program for Officers of Northeast Utilities System Companies. The agreements and the Special Severance Program are also binding on Northeast Utilities and, except for Mr. Shivery's agreement, on certain majority-owned subsidiaries of Northeast Utilities.

The agreements with Messrs. Shivery, Forsgren and Butler and Mrs. Grisé obligate the officer to perform such duties as may be directed by the NUSCO Board of Directors or the Northeast Utilities Board of Trustees, protect the Company's confidential information, refrain, while employed by the Company and for a period of time thereafter, from competing with the Company in a specified geographic area, and provide that the officer's base salary will not be reduced below certain levels without the consent of the officer. These agreements also provide that the officer will participate in specified benefits under the Supplemental Executive Retirement Plan or other supplemental retirement programs (see Pension Benefits, above) and/or in certain executive incentive programs at specified incentive opportunity levels, for a specified employment term and for automatic one-year extensions of the employment term unless at least six months' notice of non-renewal is given by either party. The employment term may also be ended by the Company for "cause," as defined, at any time (in which case no supplemental retirement benefit, if any, shall be due), or by the officer on thirty days' prior written notice for any reason. Absent "cause," the Company may remove the officer from his or her position on sixty days' prior written notice, but in the event the officer is so removed and signs a release of all claims against the Company, the officer will receive two years' base salary and annual incentive payments, specified employee welfare and pension benefits, and vesting of specified long-term incentive compensation.

Under the terms of these agreements and the Special Severance Program, upon any termination of employment following a change of control, as defined, between (a) the earlier of the date shareholders approve a change of control transaction or a change of control transaction occurs and (b) the earlier of the date, if any, on which the Board of Trustees abandons the transaction or the date two years following the change of control, if the officer signs a release of all claims against the Company, the officer will be entitled to certain payments including a multiple (not to exceed three) of annual base salary, annual incentive payments, specified employee welfare and pension benefits, and vesting of stock appreciation rights, options and restricted stock. Certain of the change of control provisions may be modified by the Board of Trustees prior to a change of control, on at least two years' notice to the affected officer(s).

Besides the terms described above, Mr. Shivery's employment agreement provides for a specified initial salary, cash, and stock options upon employment, a special incentive program and special retirement benefits, and Mr. Forsgren's employment agreement provides for special retirement benefits. See Pension Benefits, above, for further description of these provisions. The agreements of Mr. Forsgren and Mrs. Grisé were supplemented during 2001 to provide for special deferred compensation of $520,000 and $500,000, respectively, which payments were vested and paid in even installments (adjusted to reflect investment performance) on June 28, 2002, 2003 and 2004.

A letter agreement reflecting the terms of employment of Mr. Olivier provide for specified initial salary, restricted shares, and stock options, retirement and other benefits upon employment.

The descriptions of the various agreements set forth above are for purpose of disclosure in accordance with the proxy and other disclosure rules of the SEC and shall not be controlling on any party; the actual terms of the agreements themselves determine the rights and obligations of the parties.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

NU.

Incorporated herein by reference is the information contained in the sections "Common Stock Ownership of Certain Beneficial Owners," "Common Stock Ownership of Management," and "Securities Authorized for Issuance Under Equity Compensation Plans" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2005, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

CL&P, PSNH, and WMECO.

NU owns 100% of the outstanding common stock of registrants CL&P, PSNH, and WMECO. The following table sets forth, as of March 1, 2005, (except for Mr. Forsgren's beneficial ownership, which is given as of December 31, 2004, his last day as an Executive Officer of these companies) the beneficial ownership of the equity securities of NU by (i) the Chief Executive Officer of each of CL&P, PSNH and WMECO and the Executive Officers of CL&P, PSNH, and WMECO listed on the Summary Compensation Table in Item 11 and (ii) all of the current Executive Officers and directors of each of CL&P, PSNH and WMECO, as a group. No equity securities of CL&P, PSNH, or WMECO are owned by the Directors and Executive Officers of CL&P, PSNH, and WMECO. Unless otherwise noted, each Director and Executive Officer of CL&P, PSNH, and WMECO has sole voting and investment power with respect to the listed shares.

Title of Class	Name		Amount of Nature of Beneficial Ownership	Percent of Class
NU Common	Gregory B. Butler	(1)	44,957	(2)
NU Common	John H. Forsgren	(3)	164,226	(2)
NU Common	Cheryl W. Grisé	(4)	214,743	(2)
NU Common	Kerry J. Kuhlman (WMECO)	(5)	40,104	(2)
NU Common	Gary A. Long (PSNH)	(6)	38,595	(2)
NU Common	Leon J. Olivier (CL&P)	(7)	26,397	(2)
NU Common	Charles W. Shivery	(8)	63,413	(2)

Amount beneficially owned by Directors and Executive Officers as a group:

Company	Number of Persons	Amount and Nature of Beneficial Ownership	Percent of Outstanding
CL&P	7	571,846	(2)
PSNH	8	578,543	(2)
WMECO	7	603,257	(2)

Notes:

(1) Includes 29,800 shares that could be acquired by Mr. Butler pursuant to currently exercisable options and 3,890 shares as to which Mr. Butler has sole voting and no dispositive power.

(2) As of March 1, 2004, the Directors and Executive Officers of CL&P, PSNH, or WMECO individually and as a group, owned less than one percent of the shares outstanding.

(3) Includes 134,266 shares that could have been acquired by Mr. Forsgren as of December 31, 2004 pursuant to then currently exercisable options and 28,343 shares as of December 31, 2004 as to which Mr. Forsgren had sole voting and no dispositive power.

(4) Includes 171,228 shares that could be acquired by Mrs. Grisé pursuant to currently exercisable options and 14,779 shares as to which Mrs. Grisé has sole voting and no dispositive power, and 265 shares held by Mrs. Grisé's husband as custodian for her children, with whom she shares voting and dispositive power.

(5) Includes 28,864 shares that could be acquired by Mrs. Kuhlman pursuant to currently exercisable options and 2,210 shares as to which Mrs. Kuhlman has sole voting and no dispositive power.

(6) Includes 28,050 shares that could be acquired by Mr. Long pursuant to currently exercisable options and 2,299 shares as to which Mr. Long has sole voting and no dispositive power.

(7) Includes 19,900 shares that could be acquired by Mr. Olivier pursuant to currently exercisable options and 2,776 shares as to which Mr. Olivier has sole voting and no dispositive power.

(8) Includes 19,349 shares that could be acquired by Mr. Shivery pursuant to currently exercisable options and 26,530 shares as to which Mr. Shivery has sole voting and no dispositive power.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth the number of Common Shares of Northeast Utilities issuable under the equity compensation plans of the Northeast Utilities System, as well as their weighted exercise price, in accordance with the rules of the Securities and Exchange Commission:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise Price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	2,054,937	$18.596	See Note 1
Equity compensation plans not approved by security holders	0	0	None
Total	2,054,937	$18.596	See Note 1

Notes to table:

1. Under the Northeast Utilities Incentive Plan, 6,301,994 shares were available for issuance as of December 31, 2004. In addition, an amount equal to one percent of the outstanding shares as of the end of each year becomes available for issuance under the Incentive Plan the following year. Under the Northeast Utilities Employee Share Purchase Plan II, 6,723,969 additional shares are available for issuance. Each such plan expires in 2008.

Item 13. Certain Relationships and Related Transactions

Incorporated herein by reference is the information contained in the section "Certain Relationships and Related Transactions" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2005, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

Item 14. Principal Accountant Fees and Services

NU

Incorporated herein by reference is the information contained in the sections "Pre-Approval of Services Provided by Principal Auditors" and "Fees Paid to Principal Auditor" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, to be dated March 31, 2005, which will be filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934.

CL&P, WMECO, PSNH

None of CL&P, WMECO and PSNH are subject to the audit committee requirements of the Securities and Exchange Commission, the national securities exchanges or the national securities associations. CL&P, WMECO and PSNH obtain audit services from the independent auditor engaged by the Audit Committee of NU's Board of Trustees. The NU Audit Committee has established policies and procedures regarding the pre-approval of services provided by the principal auditors. Those policies and procedures delegate pre-approval

of services to the NU Audit Committee Chair and/or Vice Chair provided that such offices are held by NU Trustees who are "independent" within the meaning of the Sarbanes-Oxley Act of 2002 (SOX) and that all such pre-approvals are presented to the Audit Committee at the next regularly scheduled meeting of the Committee. The following relates to fees and services for the entire Northeast Utilities System, including CL&P, WMECO, and PSNH:

Fees Paid to Principal Auditor

The Company's principal auditor was paid fees aggregating $2,930,455 and $ 1,735,113 for the years ended December 31, 2004 and 2003, respectively, comprised of the following:

1. Audit Fees

The aggregate fees billed to NU and its subsidiaries by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu and their respective affiliates (collectively, the "Deloitte Entities") for audit services rendered for the years ended December 31, 2004 and 2003 totaled $2,679,300 and $1,441,700, respectively. The audit fees were incurred for audits of the annual consolidated financial statements of NU and its subsidiaries, reviews of financial statements included in quarterly reports on Form 10-Q of NU and its subsidiaries, comfort letters, consents and other costs related to registration statements and financings. The 2004 fees also included an audit of internal controls over financial reporting as of December 31, 2004.

2 Audit Related Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for audit related services rendered for the years ended December 31, 2004 and 2003 totaled $174,950 and $150,200, respectively, primarily related to the examination of management's assertions of CL&P's, PSNH's and WMECO's securitization subsidiaries and the Company's 401k Plan.

3. Tax Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for tax services for the years ended December 31, 2004 and 2003 totaled $54,965 and $47,500, respectively. These services related solely to reviews of tax returns. There were no services related to tax advice or tax planning.

4. All Other Fees

The aggregate fees billed to NU and its subsidiaries by the Deloitte Entities for the years ended December 31, 2004 and 2003 for services other than the services described above totaled $21,240 and $95,713, respectively, primarily related to tax return software licensing and training classes provided by the Deloitte Entities. Included in 2003 "all other fees" are $16,620 (1% of total fees) of services where pre-approval was not required, as such services were de minimis.

The NU Audit Committee has considered whether the provision by the Deloitte Entities of the non-audit services described above was allowed under Rule 2-01(c)(4) of Regulation S-X and was compatible with maintaining auditor independence and has concluded that the Deloitte Entities were and are independent of the Company in all respects.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements:

The Reports the of Independent Registered Public Accounting Firm and financial statements of CL&P, PSNH and WMECO are hereby incorporated by reference and made a part of this report (see "Item 8. Financial Statements and Supplementary Data").

Report of Independent Registered Public Accounting Firm	S-1

2. Schedules:

Financial Statement Schedules for NU (Parent), NU and Subsidiaries, CL&P and Subsidiaries, PSNH and Subsidiaries, and WMECO and Subsidiary are listed in the Index to Financial Statements Schedules	S-2
3. Exhibits Index	E-1

NORTHEAST UTILITIES

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHEAST UTILITIES
(Registrant)

Date: March 16, 2005

By /s/ Charles W. Shivery
Charles W. Shivery
Chairman of the Board,
President and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 16, 2005	Chairman of the Board, President and Chief Executive Officer, and a Trustee (Principal Executive Officer)	/s/ Charles W. Shivery Charles W. Shivery
March 16, 2005	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ David R. McHale David R. McHale
March 16, 2005	Vice President - Accounting and Controller	/s/ John P. Stack John P. Stack
March 16 , 2005	Trustee	/s/ Richard H. Booth Richard H. Booth
March 16, 2005	Trustee	/s/ Cotton M. Cleveland Cotton M. Cleveland
March 16, 2005	Trustee	/s/ Sanford Cloud, Jr. Sanford Cloud, Jr.
March 16, 2005	Trustee	/s/ James F. Cordes James F. Cordes
March 16, 2005	Trustee	/s/ E. Gail de Planque E. Gail de Planque
March 16, 2005	Trustee	/s/ John G. Graham John G. Graham
March 16, 2005	Trustee	/s/ Elizabeth T. Kennan Elizabeth T. Kennan
March 16, 2005	Trustee	/s/ Robert E. Patricelli Robert E. Patricelli
March 16, 2005	Trustee	/s/ John F. Swope John F. Swope

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

Date: March 16, 2005

By /s/ Cheryl W. Grisé
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 16, 2005	Chief Executive Officer and a Director (Principal Executive Officer)	/s/ Cheryl W. Grisé Cheryl W. Grisé
March 16, 2005	President and Chief Operating Officer and a Director	/s/ Raymond P. Necci Raymond P. Necci
March 16, 2005	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ David R. McHale David R. McHale
March 16, 2005	Vice President - Accounting and Controller	/s/ John P. Stack John P. Stack
March 16, 2005	Director	/s/ Leon J. Olivier Leon J. Olivier

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
(Registrant)

Date: March 16, 2005

By /s/ Cheryl W. Grisé
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 16, 2005	Chief Executive Officer and a Director (Principal Executive Officer)	/s/ Cheryl W. Grisé Cheryl W. Grisé
March 16, 2005	President and Chief Operating Officer and a Director	/s/ Gary A. Long Gary A. Long
March 16, 2005	Senior Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	/s/ David R. McHale David R. McHale
March 16, 2005	Vice President - Accounting and Controller	/s/ John P. Stack John P. Stack
March 16, 2005	Director	/s/ Leon J. Olivier Leon J. Olivier

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
(Registrant)

Date: March 16, 2005

By /s/ Cheryl W. Grisé
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 16, 2005	Chief Executive Officer and a Director (Principal Executive Officer)	/s/ Cheryl W. Grisé Cheryl W. Grisé
March 16, 2005	President and Chief Operating Officer and a Director	/s/ Rodney O. Powell Rodney O. Powell
March 16, 2005	Senior Vice President and Chief Financial Officer and a Director (Principal Financial Officer)	/s/ David R. McHale David R. McHale
March 16, 2005	Vice President - Accounting and Controller	/s/ John P. Stack John P. Stack
March 16, 2005	Director	/s/ Leon J. Olivier Leon J. Olivier

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities and the Boards of Directors of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company:

We have audited the consolidated financial statements of Northeast Utilities and subsidiaries (the "Company"), The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH") and Western Massachusetts Electric Company ("WMECO") (collectively "the Companies") as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated March 16, 2005; such consolidated financial statements and reports are included in Northeast Utilities' 2004 Annual Report to Shareholders and in CL&P's, PSNH's and WMECO's 2004 Annual Reports, all of which are incorporated herein by reference. Our report on the consolidated financial statements of Northeast Utilities expresses an unqualified opinion and includes explanatory paragraphs with respect to the Company's 2003 adoption of Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities* and the Company's restatement of the consolidated balance sheet as of December 31, 2003 and the related consolidated statement of cash flows for the year then ended. Our report on management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 expresses an unqualified opinion on management's assessment and an adverse opinion on the effectiveness of the Company's internal control over financial reporting because of a material weakness.

Our audits also included the consolidated financial statement schedules of the Company, CL&P, PSNH and WMECO, listed in Item 15. These consolidated financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
March 16, 2005

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II.	Valuation and Qualifying Accounts and Reserves for 2004, 2003, and 2002:	
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All other schedules of the companies' for which provision is made in the applicable regulations of the SEC are not required under the related instructions or are not applicable, and therefore have been omitted.

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AT DECEMBER 31, 2004 AND 2003
(Thousands of Dollars)

	2004	2003
ASSETS		
Current Assets:		
Cash	$ 244	$ -
Notes receivable from affiliated companies	210,600	259,600
Notes and accounts receivable	1,129	3,116
Accounts receivable from affiliated companies	126	1,973
Taxes receivable	6,291	2,314
Derivative assets - current	91	-
Prepayments	115	313
	218,596	267,316
Deferred Debits and Other Assets:		
Investments in subsidiary companies, at equity	2,637,567	2,544,819
Other	12,997	14,565
	2,650,564	2,559,384
Total Assets	$ 2,869,160	$ 2,826,700
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 100,000	$ 65,000
Long-term debt - current portion	26,000	24,000
Accounts payable	7	1,834
Accounts payable to affiliated companies	1,015	25
Accrued interest	5,790	6,048
Other	327	346
	133,139	97,253
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	3,525	4,261
Derivative liabilities - long-term	-	3,576
Other	1,933	1,375
	5,458	9,212
Capitalization:		
Long-Term Debt	433,852	456,115
Common shares, $5 par value - authorized 225,000,000 shares; 151,230,981 shares issued and 129,034,442 shares outstanding in 2004 and 150,398,403 shares issued and 127,695,999 outstanding in 2003	756,155	751,992
Capital surplus, paid in	1,116,106	1,108,924
Deferred contribution plan - employee stock ownership plan	(60,547)	(73,694)
Retained earnings	845,343	808,932
Accumulated other comprehensive (loss)/income	(1,220)	25,991
Treasury stock, 19,580,065 shares in 2004 and 19,518,023 outstanding in 2003	(359,126)	(358,025)
Common Shareholders' Equity	2,296,711	2,264,120
Total Capitalization	2,730,563	2,720,235
Total Liabilities and Capitalization	$ 2,869,160	$ 2,826,700

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF INCOME
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002
(Thousands of Dollars, Except Share Information)

	2004	2003	2002
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	8,417	7,720	12,787
Operating Loss	(8,417)	(7,720)	(12,787)
Interest Expense	24,868	22,186	30,630
Other Income:			
Equity in earnings of subsidiaries	131,127	123,647	158,191
Gain related to sale of nuclear plants	-	-	14,255
Other, net	13,538	11,041	13,002
Other Income, Net	144,665	134,688	185,448
Income Before Income Tax Benefit	111,380	104,782	142,031
Income Tax Benefit	(5,208)	(11,629)	(10,078)
Earnings for Common Shares	$ 116,588	$ 116,411	$ 152,109
Basic and Fully Diluted Earnings Per Common Share	$ 0.91	$ 0.91	$ 1.18
Basic Common Shares Outstanding (weighted average)	128,245,860	127,114,743	129,150,549
Fully Diluted Common Shares Outstanding (weighted average)	128,396,076	127,240,724	129,341,360

SCHEDULE I

NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
AT DECEMBER 31, 2004, 2003 AND 2002
(Thousands of Dollars)

	2004	2003	2002
Operating Activities:			
Net income	$ 116,588	$ 116,411	$ 152,109
Adjustments to reconcile to net cash flows (used in)/provided by operating activities:			
Equity in earnings of subsidiary companies	(131,127)	(123,647)	(158,191)
Deferred income taxes	(811)	(411)	(565)
Other sources of cash	15,253	15,286	16,504
Other uses of cash	(1,101)	(8,492)	(5,011)
Changes in current assets and liabilities:			
Receivables, net	3,834	(1,918)	19,097
Other current assets (excludes cash)	(3,779)	(2,554)	1,020
Accounts payable	(837)	(716)	(24,197)
Accrued taxes	-	(2,460)	2,211
Other current liabilities	(24,936)	13,764	51,132
Net cash flows (used in)/provided by operating activities	(26,916)	5,263	54,109
Investing Activities:			
Investment in subsidiaries	(47,467)	(213,191)	102,019
Cash dividends received from subsidiary companies	85,846	114,921	126,154
Other investment activities	573	3,782	1,595
Net cash flows provided by/(used in) investing activities	38,952	(94,488)	229,768
Financing Activities:			
Issuance of common shares	10,937	13,654	7,458
Repurchase of common shares	-	(20,537)	(57,800)
Increase in short-term debt	35,000	16,000	9,000
Issuance of long-term debt	-	150,000	263,000
Reacquisitions and retirements of long-term debt	(24,000)	(23,000)	(286,000)
NU Money Pool borrowing/(lending)	49,000	29,500	(164,300)
Cash dividends on common shares	(80,177)	(73,090)	(67,793)
			-
Other financing activities	(2,552)	(3,927)	
Net cash flows (used in)/provided by financing activities	(11,792)	88,600	(296,435)
Net increase/(decrease) in cash	244	(625)	(12,558)
Cash - beginning of year	-	625	13,183
Cash - end of year	$ 244	$ -	$ 625
Supplemental Cash Flow Information:			
Cash paid/(refunded) during the year for:			
Interest, net of amounts capitalized	$ 6,048	$ 21,496	$ 25,213
Income taxes	$ 535	$ (16,818)	$ (10,677)

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2004
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions- describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 40,846	$ 19,062	$ -	$ 34,583	(a)	$ 25,325
Reserves not applied against assets:						
Operating reserves	$ 68,658	$ 22,574	$ -	$ 19,466	(b)	$ 71,766

(a) Amounts written off, net of recoveries and other adjustments.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2003
(Thousands of Dollars)

Column A	*Column B*	*Column C*		*Column D*	*Column E*
		Additions			
		(1)	(2)		
Description	**Balance at beginning of period**	**Charged to costs and expenses**	**Charged to other accounts - describe**	**Deductions- describe**	**Balance at end of period**
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 15,425	$ 23,229	$ 17,205 (a)	$ 15,013 (b)	$ 40,846
Reserves not applied against assets:					
Operating reserves	$ 67,127	$ 17,688	$ -	$ 16,157 (c)	$ 68,658

(a) Amount relates to regulatory assets recorded in conjunction with the bankruptcy of NRG and certain of its subsidiaries and to uncollectible amounts reserved for related to capital projects and New Hampshire's low-income assistance program.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Northeast Utilities and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2002
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions- describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 16,353	$ 16,590	$ -	$ 17,518	(a)	$ 15,425
Reserves not applied against assets:						
Operating reserves	$ 69,085	$ 18,959	$ -	$ 20,.917	(b)	$ 67,127

(a) Amounts written off, net of recoveries.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2004
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions- describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 21,790	$ 1,440	$ -	$ 21,220	(a)	$ 2,010
Reserves not applied against assets:						
Operating reserves	$ 21,364	$ 10,201	$ -	$ 4,160	(b)	$ 27,405

(a) Amounts written off, net of recoveries and other adjustments.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2003
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions-describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 525	$ 5,164	$ 16,924	(a) $ 823	(b)	$ 21,790
Reserves not applied against assets:						
Operating reserves	$ 18,241	$ 9,712	$ -	$ 6,589	(c)	$ 21,364

(a) Amount relates to regulatory assets recorded in conjunction with the bankruptcy of NRG and certain of its subsidiaries and to uncollectible amounts reserved for related to capital projects.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

The Connecticut Light and Power Company and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2002
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions-describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 525	$ 398	$ -	$ 398	(a)	$ 525
Reserves not applied against assets:						
Operating reserves	$ 11,387	$ 13,755	$ -	$ 6,901	(b)	$ 18,241

(a) Amounts written off, net of recoveries.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2004
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions- describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 1,590	$ 2,742	$ 110 (a)	$ 2,457 (b)	$ 1,764
Reserves not applied against assets:					
Operating reserves	$ 13,568	$ 5,066	$ -	$ 7,173 (c)	$ 11,461

(a) Amount relates to regulatory assets recorded in conjunction with uncollectible amounts reserved for related to capital projects and New Hampshire's low-income assistance program.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2003
(Thousands of Dollars)

Column A	Column B	Column C			Column D		Column E
		Additions					
		(1)	(2)				
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe		Deductions- describe		Balance at end of period
Reserves deducted from assets to which they apply:							
Reserves for uncollectible accounts	$ 1,990	$ 1,379	$ 102	(a)	$ 1,881	(b)	$ 1,590
Reserves not applied against assets:							
Operating reserves	$ 14,089	$ 2,585	$ -		$ 3,106	(c)	$ 13,568

(a) Amount relates to regulatory assets recorded in conjunction with uncollectible amounts reserved for related to New Hampshire's low-income assistance program.

(b) Amounts written off, net of recoveries.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

Public Service Company of New Hampshire and Subsidiaries
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2002
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions- describe	Balance at end of period
Reserves deducted from assets to which they apply:					
Reserves for uncollectible accounts	$ 1,736	$ 1,840	$ -	$ 1,586 (a)	$ 1,990
Reserves not applied against assets:					
Operating reserves	$ 13,842	$ 3,088	$ -	$ 2,841 (b)	$ 14,089

(a) Amounts written off, net of recoveries.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2004
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions-describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 2,551	$ 4,245	$ -	$ 4,233	(a)	$ 2,563
Reserves not applied against assets:						
Operating reserves	$ 2,971	$ 1,126	$ -	$ 1,742	(b)	$ 2,355

(a) Amounts written off, net of recoveries.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, inventory reserves and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2003
(Thousands of Dollars)

Column A	Column B	Column C			Column D		Column E
		Additions					
		(1)	(2)				
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe		Deductions- describe		Balance at end of period
Reserves deducted from assets to which they apply:							
Reserves for uncollectible accounts	$ 1,958	$ 4,107	$ 179	(a)	$ 3,693	(b)	$ 2,551
Reserves not applied against assets:							
Operating reserves	$ 2,855	$ 1,501	$ -		$ 1,385	(c)	$ 2,971

(a) Amount relates to uncollectible amounts reserved for related to capital projects.

(b) Amounts written off, net of receivables.

(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

Schedule II

Western Massachusetts Electric Company and Subsidiary
Valuation and Qualifying Accounts and Reserves
Year Ended December 31, 2002
(Thousands of Dollars)

Column A	Column B	Column C		Column D		Column E
		Additions				
		(1)	(2)			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts - describe	Deductions-describe		Balance at end of period
Reserves deducted from assets to which they apply:						
Reserves for uncollectible accounts	$ 2,028	$ 2,755	$ -	$ 2,825	(a)	$ 1,958
Reserves not applied against assets:						
Operating reserves	$ 7,506	$ 1,598	$ -	$ 6,249	(b)	$ 2,855

(a) Amounts written off, net of recoveries.

(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

EXHIBIT INDEX

Each document described below is incorporated by reference to the files identified, unless designated with a (*), which exhibits are filed herewith.

Exhibit Number	Description
2	Plan of acquisition, reorganization, arrangement, liquidation or succession
	(A) NU
	2.1 Amended and Restated Agreement and Plan of Merger (Exhibit 1 to NU Form 8-K dated December 2, 1999, File No. 1-5324).
3	Articles of Incorporation and By-Laws
	(A) Northeast Utilities
	3.1 Declaration of Trust of NU, as amended through May 13, 2003. (Exhibit 4.1 to NU Form S-8 filed June 11, 2003, File No. 333-106008).
	(B) The Connecticut Light and Power Company
	3.1 Certificate of Incorporation of CL&P, restated to March 22, 1994. (Exhibit 3.2.1, 1993 NU Form 10-K, File No. 1-5324)
	3.1.2 Certificate of Amendment to Certificate of Incorporation of CL&P, dated December 26, 1996. (Exhibit 3.2.2, 1996 NU Form 10-K, File No. 1-5324)
	3.1.3 Certificate of Amendment to Certificate of Incorporation of CL&P, dated April 27, 1998. (Exhibit 3.2.3, 1998 NU Form 10-K, File No. 1-5324)
	3.2 By-laws of CL&P, as amended to January 1, 1997. (Exhibit 3.2.3, 1996 NU Form 10-K, File No. 1-5324)
	(C) Public Service Company of New Hampshire
	3.1 Articles of Incorporation, as amended to May 16, 1991. (Exhibit 3.3.1, 1993 NU Form 10-K, File No. 1-5324)
	3.2 By-laws of PSNH, as amended to November 1, 1993. (Exhibit 3.3.2, 1993 NU Form 10-K, File No. 1-5324)
	(D) Western Massachusetts Electric Company
	3.1 Articles of Organization of WMECO, restated to February 23, 1995. (Exhibit 3.4.1, 1994 NU Form 10-K, File No. 1-5324)
	3.2 By-laws of WMECO, as amended to April 1, 1999. (Exhibit 3.1, NU Form 10-Q for the Quarter Ended June 30, 1999, File No. 1-5324)
	3.1.2 By-laws of WMECO, as further amended to May 1, 2000. (Exhibit 3.1, NU Form 10-Q for the Quarter Ended June 30, 2000, File No. 1-5324)
4	Instruments defining the rights of security holders, including indentures
	(A) Northeast Utilities
	4.1 Indenture dated as of December 1, 1991 between Northeast Utilities and IBJ Schroder Bank & Trust Company, with respect to the issuance of Debt Securities. (Exhibit 4.1.1, 1991 NU Form 10-K, File No. 1-5324)

4.1.1 First Supplemental Indenture dated as of December 1, 1991 between Northeast Utilities and IBJ Schroder Bank & Trust Company, with respect to the issuance of Series A Notes. (Exhibit 4.1.2, 1991 NU Form 10-K, File No. 1-5324)

4.1.2 Second Supplemental Indenture dated as of March 1, 1992 between Northeast Utilities and IBJ Schroder Bank & Trust Company with respect to the issuance of 8.38% Amortizing Notes. (Exhibit 4.1.3, 1992 NU Form 10-K, File No. 1-5324)

4.2 Rights Agreement dated as of February 23, 1999, between Northeast Utilities and Northeast Utilities Service Company, as Rights Agent. (Exhibit 1 to NU's Registration Statement on Form 8-A, filed on April 12, 1999, File No. 001-05324).

4.2.1 Amendment to Rights Agreement. (Exhibit 3 to NU Form 8-K dated October 13, 1999, File No. 1-5324).

4.2.2 Second Amendment to Rights Agreement. (Exhibit B-3 to NU 35-CERT, dated February 1, 2002, File No. 070-09463).

4.3 Indenture dated as of April 1, 2002, between NU and the Bank of New York as Trustee. (Exhibit A-3 to NU 35-CERT filed April 9, 2002, File No. 70-9535)

4.3.1 First Supplemental Indenture dated as of April 1, 2002, between NU and the Bank of New York as Trustee, relating to $263M of Senior Notes, Series A, due 2012. (Exhibit A-4 to NU 35-CERT filed April 9, 2002, File No. 70-9535)

4.3.2 Second Supplemental Indenture dated as of June 1, 2003, between NU and the Bank of New York as Trustee, relating to $150M of Senior Notes, Series B, due 2008. (Exhibit A-1.3 to NU 35-CERT filed June 6, 2003, File No. 70-10051)

4.4 Credit Agreement among Northeast Utilities, the Banks Named Therein, Union Bank of California, N.A. as Administrative Agent and JPMorgan Chase Bank, dated as of November 8, 2004. (Exhibit B-8 to NU 35-CERT filed November 17, 2004, File No. 70-9755)

(B) The Connecticut Light and Power Company

4.1 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921. (Composite including all twenty-four amendments to May 1, 1967.) (Exhibit 4.1.1, 1989 NU Form 10-K, File No. 1-5324)

4.1.1 Supplemental Indenture to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of June 1, 1994. (Exhibit 4.2.15, 1994 NU Form 10-K, File No. 1-5324)

4.1.2 Supplemental Indentures to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of October 1, 1994. (Exhibit 4.2.16, 1994 NU Form 10-K, File No. 1-5324)

4.1.3 Series A Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee, dated as of September 1, 2004 (Exhibit 99.2 to CL&P Form 8-K filed September 22, 2004, File No. 0-00404).

4.1.4 Form of Composite Indenture of Mortgage, as proposed to be amended and restated (included as Schedule C to the Series A Supplemental Indenture) dated as of May 1, 1921, as amended and supplemented (Exhibit 99.4 to CL&P Form 8-K filed September 22, 2004, File No. 0-00404).

4.1.5 Series B Supplemental Indenture between CL&P and Deutsche Bank Trust Company Americas, as Trustee dated as of September 1, 2004 (Exhibit 99.5 to CL&P Form 8-K filed September 22, 2004, File No. 0-00404).

4.2 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1986 Series) dated as of December 1, 1986. (Exhibit C.1.47, 1986 NU Form U5S, File No. 30-246)

4.3 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1988 Series) dated as of October 1, 1988. (Exhibit C.1.55, 1988 NU Form U5S, File No. 30-246)

4.4 Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire, CL&P and the Trustee (Pollution Control Bonds, 1992 Series A) dated as of December 1, 1992. (Exhibit C.2.33, 1992 NU Form U5S, File No. 30-246)

4.5 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.21, 1993 NU Form 10-K, File No. 1-5324)

4.6 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series B, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.22, 1993 NU Form 10-K, File No. 1-5324)

4.7 Amended and Restated Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Revenue Bond - 1996A Series) dated as of May 1, 1996 and Amended and Restated as of January 1, 1997. (Exhibit 4.2.24, 1996 NU Form 10-K, File No. 1-5324)

4.8 Amended and Restated Indenture of Trust between Connecticut Development Authority and the Trustee (CL&P Pollution Control Revenue Bond-1996A Series), dated as of May 1, 1996 and Amended and Restated as of January 1, 1997. (Exhibit 4.2.24.1, 1996 NU Form 10-K, File No. 1-5324)

4.9 Standby Bond Purchase Agreement among CL&P, Bank of New York as Purchasing Agent and the Banks Named therein, dated October 24, 2000. (Exhibit 4.2.24.2 of 2000 NU Form 10-K, File No. 1-5324)

4.9.1 Amendment No. 2 to the Standby Bond Purchase Agreement dated as of September 9, 2002, among CL&P, The Bank of New York, and the Participating Banks referred to therein. (Exhibit 4.2.7.4, NU Form 10-Q for the Quarter Ended September 30, 2002, File No. 1-5324)

4.10 AMBAC Municipal Bond Insurance Policy issued by the Connecticut Development Authority (CL&P Pollution Control Revenue Bond-1996A Series), effective January 23, 1997.(Exhibit 4.2.24.3, 1996 NU Form 10-K, File No. 1-5324)

4.11 Compensation and Multiannual Mode Agreement among the Connecticut Development Authority and BNY Capital Markets, Inc. dated September 23, 2003 (Exhibit 4.2.7.5, NU Form 10-Q for the Quarter Ended September 30, 2003, File No. 1-5324)

4.12 Amended and Restated Receivables Purchase and Sale Agreement dated as of March 30, 2001). (Exhibit 4.2.8, 2002 NU Form 10-K, File No. 1-5324)

4.12.1 Amendment No. 2 to the Purchase and Sale Agreement dated as of July 10, 2002 (Exhibit 4.2.24.2, 2002 NU Form 10-K, File No. 1-5324)

4.12.2 Amendment No. 3 to the Amended and Restated Receivables Purchase and Sales Agreement dated as of July 9, 2003 (Exhibit 4.2.8.2, NU Form 10-Q for the Quarter Ended September 30, 2003, File No. 1-5324)

4.13 Purchase and Contribution Agreement dated as of September 30, 1997 (Exhibit 10.49.1, 1997 NU Form 10-K, File No. 1-5324)

4.13.1 Amendment No. 2 to the Purchase and Contribution Agreement dated as of March 30, 2001 (Exhibit 4.2.9 of 2002 NU Form 10-K, File No. 1-5324)

4.14 Credit Agreement among WMECO, CL&P, PSNH, Yankee Gas, the Banks Named Therein and Citicorp USA, Inc. as Administrative Agent, dated as of November 8, 2004. (Exhibit B-8 to NU 35-CERT filed November 17, 2004, File No. 70-9755).

(C) Public Service Company of New Hampshire

4.1 First Mortgage Indenture dated as of August 15, 1978 between PSNH and First Fidelity Bank, National Association, New Jersey, now First Union National Bank, Trustee, (Composite including all amendments to May 16, 1991). (Exhibit 4.4.1, 1992 NU Form 10-K, File No. 1-5324)

4.1.1 Tenth Supplemental Indenture dated as of May 1, 1991 between PSNH and First Fidelity Bank, National Association, now First Union National Bank. (Exhibit 4.1, PSNH Form 8-K dated February 10, 1992, File No. 1-6392)

4.1.2 Twelfth Supplemental Indenture dated as of December 1, 2001 between PSNH and First Union National Bank. (Exhibit 4.3.1.2, 2001 NU Form 10-K, File No. 1-5324)

4.1.3 Thirteenth Supplemental Indenture, dated as of July 1, 2004, between PSNH and Wachovia Bank, National Association, successor to First Union National Bank, as successor to First Fidelity Bank, National Association, as Trustee (Exhibit 99.2 to PSNH Form 8-K filed October 5, 2004, File No. 1-6392).

4.2 Series D (Tax Exempt Refunding) Amended and Restated PCRB Loan and Trust Agreement dated as of April 1, 1999. (Exhibit 4.3.6, 1999 NU Form 10-K, File No. 1-5324)

4.3 Series E (Tax Exempt Refunding) Amended & Restated PCRB Loan and Trust Agreement dated as of April 1, 1999. (Exhibit 4.3.7, 1999 NU Form 10-K, File No. 1-5324)

4.4 Series A Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001. (Exhibit 4.3.4, 2001 NU Form 10-K, File No. 1-5324)

4.5 Series B Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001. (Exhibit 4.3.5, 2001 NU Form 10-K, File No. 1-5324)

4.6 Series C Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire and PSNH and State Street Bank and Trust Company, as Trustee (Tax Exempt Pollution Control Bonds) dated as of October 1, 2001. (Exhibit 4.3.6, 2001 NU Form 10-K, File No. 1-5324)

4.7 Credit Agreement among WMECO, CL&P, PSNH, Yankee Gas, the Banks Named Therein and Citicorp USA, Inc. as Administrative Agent, dated as of November 8, 2004. (Exhibit B-8 to NU 35-CERT filed November 17, 2004, File No. 70-9755).

(D) Western Massachusetts Electric Company

4.1 Loan Agreement between Connecticut Development Authority and WMECO, (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.4.13, 1993 NU Form 10-K, File No. 1-5324)

4.2 Indenture between WMECO and the Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.2, WMECO Form 8-K filed October 8, 2003, File No. 0-7624)

4.2.1 First Supplemental Indenture between WMECO and the Bank of New York, as Trustee, dated as of September 1, 2003 (Exhibit 99.3, WMECO Form 8-K filed October 8, 2003, File No. 0-7624)

4.2.2 Second Supplemental Indenture dated as of September 1, 2004, between WMECO and Morgan Stanley & Co. (Exhibit 4.1 to WMECO Form 8-K filed September 27, 2004, File No. 0-7624).

4.3 Credit Agreement among WMECO, CL&P, PSNH, Yankee Gas, the Banks Named Therein and Citicorp USA, Inc. as Administrative Agent, dated as of November 8, 2004. (Exhibit B-8 to NU 35-CERT filed November 17, 2004, File No. 70-9755).

10 Material Contracts

(A) NU

10.1 Lease dated as of April 14, 1992 between The Rocky River Realty Company and Northeast Utilities Service Company with respect to the Berlin, Connecticut headquarters. (Exhibit 10.29, 1992 NU Form 10-K, File No. 1-5324)

10.2 Loan Agreement dated as of December 2, 1991, by and between NU and Mellon Bank, N.A., as Trustee, with respect to NU's loan of $175 million to an ESOP Trust. (Exhibit 10.46, 1991 NU Form 10-K, File No. 1-5324)

10.2.1 First Amendment to Loan Agreement dated February 7, 1992. (Exhibit 10.36.1, 1993 NU Form 10-K, File No. 1-5324)

10.2.2 Second Amendment to Loan Agreement dated April 9, 1992. (Exhibit 10.36.3, 1993 NU Form 10-K, File No. 1-5324)

10.3 Loan Agreement dated as of March 19, 1992 by and between NU and Mellon Bank, N.A., as Trustee, with respect to NU's loan of $75 million to the ESOP Trust. (Exhibit 10.49.1, 1992 NU Form 10-K, File No. 1-5324)

10.4 Indenture Mortgage, dated as of October 18, 2001 between NGC and The Bank of New York, as Trustee. (Exhibit 4.1 to NGC Registration Statement on Form S-4 dated December 6, 2001, File No. 333-74636)

10.4.1 First Supplemental Indenture Mortgage, dated as of October 18, 2001 between NGC and The Bank of New York, as Trustee. (Exhibit 4.2 to NGC Registration Statement on Form S-4 dated December 6, 2001, File No. 333-74636)

10.5 Indenture of Mortgage and Deed of Trust dated July 1, 1989 between Yankee Gas Services Company and the Connecticut National Bank, as Trustee (Exhibit 4.7, Yankee Energy System, Inc. ("YES") Form 10-K for the fiscal year ended September 30, 1990, File No. 0-10721)

10.5.1 First Supplemental Indenture of Mortgage and of Trust dated April 1, 1992 between Yankee Gas Services Company and The Connecticut National Bank, as Trustee (YES Registration Statement on Form S-3, dated October 2, 1992 Form 1992 File No. 33-52750).

10.5.2 Second Supplemental Indenture of Mortgage and Deed of Trust dated December 1, 1992 between Yankee Gas Services Company and The Connecticut National Bank, as Trustee (YES Form 10-K for the fiscal year ended September 30, 1992, File No. 0-17605).

10.5.3 Third Supplemental Indenture of Mortgage and Deed of Trust dated June 1, 1995 between Yankee Gas Services Company and Shawmut Bank Connecticut, N.A. (formerly The Connecticut National Bank), as Trustee. (Exhibit 4.14 YES Form 10-K for the fiscal year ended September 30, 1995, File No. 0-10721).

10.5.4 Fourth Supplemental Indenture of Mortgage and Deed of Trust dated April 1, 1997 between Yankee Gas Services Company and Fleet National Bank (formerly The Connecticut National Bank), as Trustee. (Exhibit 4.15 YES Form 10-K for the fiscal year ended September 30, 1997, File No. 0-10721).

10.5.5 Fifth Supplemental Indenture of Mortgage and Deed of Trust dated January 1, 1999 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank) (Exhibit 4.2 YES Form 10-Q for the fiscal quarter ended March 31, 1999, File No. 0-10721).

*10.5.6 Sixth Supplemental Indenture and Deed of Trust dated January 1, 2004 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank)

*10.5.7 Seventh Supplemental Indenture and Deed of Trust dated November 1, 2004 between Yankee Gas Services Company and The Bank of New York, as Successor Trustee to Fleet Bank (formerly The Connecticut National Bank)

(B) NU, CL&P, PSNH and WMECO

10.1 Service Contract dated as of July 1, 1966 between each of NU, CL&P and WMECO and Northeast Utilities Service Company (NUSCO). (Exhibit 10.20, 1993 NU Form 10-K, File No. 1-5324)

10.2 Form of Annual Renewal of Service Contract. (Exhibit 10.20.3, 1993 NU Form 10-K, File No. 1-5324)

10.3 Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of June 1, 1970 with respect to pooling of generation and transmission. (Exhibit 13.32, File No. 2-38177)

10.3.1 Amendment to Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of February 2, 1982 with respect to pooling of generation and transmission. (Exhibit 10.21.1, 1993 NU Form 10-K, File No. 1-5324)

10.3.2 Amendment to Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of January 1, 1984 with respect to pooling of generation and transmission. (Exhibit 10.21.2, 1994 NU Form 10-K, File No. 1-5324)

10.3.3 Second Amendment to Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of June 8, 1999 with respect to pooling of generation and transmission. (Exhibit 10.23.3, 1999 NU Form 10-K, File No. 1-5324)

10.4 Stockholder Agreement dated as of July 1, 1964 among the stockholders of Connecticut Yankee Atomic Power Company (CYAPC). (Exhibit 10.1, 1994 NU Form 10-K, File No. 1-5324)

10.5 Capital Funds Agreement dated as of September 1, 1964 between CYAPC and CL&P, HELCO, PSNH and WMECO. (Exhibit 10.3, 1994 NU Form 10-K, File No. 1-5324)

10.6 Power Purchase Contract dated as of July 1, 1964 between CYAPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 10.2, 1994 NU Form 10-K, File No. 1-5324)

10.7 Additional Power Purchase Contract dated as of April 30, 1984, between CYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.2.1, 1994 NU Form 10-K, File No. 1-5324)

10.8 Supplementary Power Contract dated as of April 1, 1987, between CYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.2.6, 1987 NU Form 10 K, File No. 1-5324)

10.9 Form of 1996 Amendatory Agreement between CYAPC and CL&P dated December 4, 1996. (Exhibit 10 (B) 10.9, 2003 NU Form 10-K, File No. 1-5324)

10.9.1 Form of First Supplemental to the 1996 Amendatory Agreement dated as of February 10, 1997 (Exhibit 10 (B) 10.9.1, 2003 NU Form 10-K, File No. 1-5324)

*10.9.2 2000 Amendatory Agreement dated as of July 28, 2000.

*10.9.3 Amended and Restated Additional Power Contract, dated as of April 30, 1984 and restated as of July 1, 2004.

10.10 Stockholder Agreement dated December 10, 1958 between Yankee Atomic Electric Company (YAEC) and CL&P, HELCO, PSNH and WMECO. (Exhibit 10.4, 1993 NU Form 10-K, File No. 1-5324)

10.11 Amended and Restated Power Purchase Contract dated as of April 1, 1985, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5, 1988 NU Form 10-K, File No. 1-5324.)

10.11.1 Amendment No. 4 to Power Contract, dated May 6, 1988, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.1, 1989 NU Form 10-K, File No. 1-5324)

10.11.2 Amendment No. 5 to Power Contract, dated June 26, 1989, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.2, 1989 NU Form 10-K, File No. 1-5324)

10.11.3 Amendment No. 6 to Power Contract, dated July 1, 1989, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.3, 1989 NU Form 10-K, File No. 1-5324)

10.11.4 Amendment No. 7 to Power Contract, dated February 1, 1992, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.4, 1993 NU Form 10-K, File No. 1-5324)

10.11.5 Form of Amendment No. 8 to Power Contract, dated June 1, 2003, between YAEC and each of CL&P, PSNH and WMECO (Exhibit 10 (B) 10.11.5, 2003 NU Form 10-K, File No. 1-5324)

10.12 Stockholder Agreement dated as of May 20, 1968 among stockholders of MYAPC. (Exhibit 10.6, 1997 NU Form 10-K, File No. 1-5324)

10.13 Capital Funds Agreement dated as of May 20, 1968 between MYAPC and CL&P, PSNH, HELCO and WMECO. (Exhibit 10.8, 1997 NU Form 10-K, File No. 1-5324)

10.13.1 Amendment No. 1 to Capital Funds Agreement, dated as of August 1, 1985, between MYAPC, CL&P, PSNH and WMECO. (Exhibit No. 10.8.1, 1994 NU Form 10-K, File No. 1-5324)

10.14 Power Purchase Contract dated as of May 20, 1968 between MYAPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 10.7, 1997 Form 10-K, File No. 1-5324)

10.14.1 Amendment No. 1 to Power Contract dated as of March 1, 1983 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.1, 1993 NU Form 10-K, File No. 1-5324)

10.14.2 Amendment No. 2 to Power Contract dated as of January 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.2, 1993 NU Form 10-K, File No. 1-5324)

10.14.3 Amendment No. 3 to Power Contract dated as of October 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit No. 10.7.3, 1994 NU Form 10-K, File No. 1-5324)

10.14.4 Additional Power Contract dated as of February 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.4, 1993 NU Form 10-K, File No. 1-5324)

10.15 Sharing Agreement between CL&P, WMECO, HP&E, HWP and PSNH dated as of June 1, 1992. (Exhibit 10.17, 1992 NU Form 10-K, File No. 1-5324)

10.16 Agreements among New England Utilities with respect to the Hydro-Quebec interconnection projects. (Exhibits 10(u) and 10(v); 10(w), 10(x), and 10(y), 1990 and 1988, respectively, Form 10-K of New England Electric System, File No. 1-3446.)

10.17 NU Incentive Plan, effective as of January 1, 1998. (Exhibit 10.35.1, 1998 NU Form 10-K, File No. 1-5324)

10.17.1 Amendment to NU Incentive Plan, effective as of February 23, 1999. (Exhibit 10.35.1.1, 1998 NU Form 10-K, File No. 1-5324)

10.18 Supplemental Executive Retirement Plan for Officers of NU System Companies, Amended and Restated effective as of January 1, 1992. (Exhibit 10.45.1, NU Form 10-Q for the Quarter Ended June 30, 1992, File No. 1-5324)

10.18.1 Amendment 1 to Supplemental Executive Retirement Plan, effective as of August 1, 1993.(Exhibit 10.35.1, 1993 NU Form 10-K, File No. 1-5324)

10.18.2 Amendment 2 to Supplemental Executive Retirement Plan, effective as of January 1, 1994.(Exhibit 10.35.2, 1993 NU Form 10-K, File No. 1-5324)

10.18.3 Amendment 3 to Supplemental Executive Retirement Plan, effective as of January 1, 1996.(Exhibit 10.36.3, 1995 NU Form 10-K, File No. 1-5324)

10.18.4 Amendment 4 to Supplemental Executive Retirement Plan, effective as of February 26, 2002. (Exhibit 10.35.4, 2001 NU Form 10-K, File No. 1-5324)

10.18.5 Amendment 5 to Supplemental Executive Retirement Plan, effective as of November 1, 2001. (Exhibit 10.35.5, 2001 NU Form 10-K, File No. 1-5324)

10.18.6 Amendment 6 to Supplemental Executive Retirement Plan, effective as of December 9, 2003 (Exhibit 10 (B) 10.18.6, 2003 NU Form 10-K, File No. 1-5324).

*10.18.7 Amendment 7 to Supplemental Executive Retirement Plan, effective as of February 1, 2005.

10.19 Trust under Supplemental Executive Retirement Plan dated May 2, 1994. (Exhibit 10.33, 2002 NU Form 10-K, File No. 1-5324)

10.19.1 First Amendment to Trust, effective as of December 10, 2002 (Exhibit 10 (B) 10.19.1, 2003 NU Form 10-K, File No. 1-5324).

10.20 Special Severance Program for Officers of NU System Companies, as adopted on July 15, 1998. (Exhibit 10.37, 1998 NU Form 10-K, File No. 1-5324)

10.20.1 Amendment to Special Severance Program, effective as of February 23, 1999. (Exhibit 10.37.1, 1998 NU Form 10-K, File No. 1-5324)

10.20.2 Amendment to Special Severance Program, effective as of September 14, 1999. (Exhibit 10.3, NU Form 10-Q for the Quarter Ended September 30, 1999, File No. 1-5324)

10.21 Consulting Agreement with Bruce M. Kenyon, dated as of December 21, 2002. (Exhibit 10.41.5, 2002 NU Form 10-K, File No. 1-5324)

10.22 Employment Agreement with Cheryl W. Grisé. (Exhibit 10.44, 1998 NU Form 10-K, File No. 1-5324)

10.22.1 Amendment to Grisé Employment Agreement, dated as of January 13, 1998. (Exhibit 10.44.1, 1998 NU Form 10-K, File No. 1-5324)

10.22.2 Amendment to Grisé Employment Agreement, dated as of February 23, 1999. (Exhibit 10.44.2, 1998 NU Form 10-K, File No. 1-5324)

10.22.3 Amendment to Grisé Employment Agreement, dated as of September 14, 1999. (Exhibit 10.5, NU Form 10-Q for the Quarter Ended September 30, 1999, File No. 1-5324)

10.22.4 Amendment to Grisé Employment Agreement dated as of September 19, 2001. (Exhibit 10.46.5 to NU Form 10-Q for the Quarter Ended September 30, 2001, File No. 1-5324).

10.22.5 Supplemental Compensation Arrangement with Cheryl W. Grisé, dated as of September 17, 2001. (Exhibit 10.46.4 to NU Form 10-Q for Quarter Ended September 30, 2001, File No. 1-5324)

10.23 Employment Agreement with Cheryl W. Grisé, dated as of April 1, 2003 (Exhibit 10.45.6 to NU Form 10-Q for Quarter Ended March 31, 2003, File No. 1-5324)

10.24 Employment Agreement with Charles W. Shivery, dated as of June 1, 2002. (Exhibit 10.64 to NU Form 10-Q for the Quarter Ended June 30, 2002, File No. 1-5324)

10.24.1 Arrangement with Charles W. Shivery with respect to interim compensation, effective as of January 1, 2004 (Exhibit 10.30.1 to NU Form 10-Q for the Quarter Ended March 31, 2004, File No. 1-5324)

10.25 Employment Agreement with Gregory B. Butler, dated as of October 1, 2003 (Exhibit 10 (B) 10.31, 2003 NU Form 10-K, File No. 1-5324).

10.26 Northeast Utilities Deferred Compensation Plan for Trustees, amended and restated effective January 1, 2004 (Exhibit 10.32 to NU Form 10-Q for the Quarter Ended March 31, 2004, File No. 1-5324).

10.27 Northeast Utilities Deferred Compensation Plan for Executives, amended and restated effective January 1, 2004 (Exhibit 10.33 to NU Form 10-Q for the Quarter Ended March 31, 2004, File No. 1-5324).

*10.28 Employment Agreement of Lawrence E. DeSimone, dated as of October 25, 2004.

*10.29 Transmission Operating Agreement dated as of February 1, 2005 between the Initial Participating Transmission Owners, Additional Participating Transmission Owners and ISO New England, Inc.

(C) NU and CL&P

10.1 CL&P Transition Property Purchase and Sale Agreement dated as of March 30, 2001. (Exhibit 10.55, 2001 CL&P Form 10-K, File No. 0-11419)

10.2 CL&P Transition Property Servicing Agreement dated as of March 30, 2001. (Exhibit 10.56, 2001 NU Form 10-K, File No. 1-5324)

10.3 Description of terms of employment of Leon J. Olivier (Exhibit 10 (C) 10.3, 2003 NU Form 10-K, File No. 1-5324).

(D) NU and PSNH

10.1 Revised and Conformed Agreement to Settle PSNH Restructuring, dated August 2, 1999, conformed June 23 and executed on September 22, 2000. (Exhibit 10.15.1, 2001 NU Form 10-K, File No. 1-5324)

10.2 PSNH Purchase and Sale Agreement with PSNH Funding LLC dated as of April 25, 2001. (Exhibit 10.57, 2001 NU Form 10-K, File No. 1-5324)

10.3 PSNH Servicing Agreement with PSNH Funding LLC dated as of April 25, 2001. (Exhibit 10.58, 2001 NU Form 10-K, File No. 1-5324)

10.4 PSNH Purchase and Sale Agreement with PSNH Funding LLC2 dated as of January 30, 2002. (Exhibit 10.59 2001 NU Form 10-K, File No. 1-5324)

10.5 PSNH Servicing Agreement with PSNH Funding LLC2 dated as of January 30, 2002. (Exhibit 10.60, 2001 NU Form 10-K, File No. 1-5324)

10.6 Service Contract dated as of June 5, 1992 between PSNH and NUSCO. (Exhibit 10.12.4, 1992 NU Form 10-K, File No. 1-5324)

(E) NU and WMECO

10.1 Lease and Agreement, dated as of December 15, 1988, by and between WMECO and Bank of New England, N.A., with BNE Realty Leasing Corporation of North Carolina. (Exhibit 10.63, 1988 NU Form 10-K, File No. 1-5324.)

10.2 WMECO Transition Property Purchase and Sale Agreement dated as of May 17, 2001. (Exhibit 10.61, 2001 NU Form 10-K, File No. 1-5324)

10.3 WMECO Transition Property Servicing Agreement dated as of May 17, 2001. (Exhibit 10.62, 2001 NU Form 10-K, File No. 1-5324)

*12 Ratio of Earnings to Fixed Charges

*13 Annual Report to Security Holders (Each of the Annual Reports is filed only with the Form 10-K of that respective registrant.)

13.1 Annual Report of CL&P.

13.2 Annual Report of WMECO.

13.3 Annual Report of PSNH.

*21 Subsidiaries of the Registrant

*23 Consent of Independent Registered Public Accounting Firm

*31 Rule 13a – 14(a)/15d – 14(a) Certifications

(a) Northeast Utilities

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of NU required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(b) The Connecticut Light and Power Company

Certification of Cheryl W. Grisé, Chief Executive Officer of CL&P required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(c) Public Service Company of New Hampshire

Certification of Cheryl W. Grisé, Chief Executive Officer of PSNH required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(d) Western Massachusetts Electric Company

Certification of Cheryl W. Grisé, Chief Executive Officer of WMECO required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

*31.1 Rule 13a – 14(a)/15d – 14(a) Certifications

(a) Northeast Utilities

Certification of David R. McHale, Senior Vice President and Chief Financial Officer of NU required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(b) The Connecticut Light and Power Company

Certification of David R. McHale, Senior Vice President and Chief Financial Officer of CL&P required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(c) Public Service Company of New Hampshire

Certification of David R. McHale, Senior Vice President and Chief Financial Officer of PSNH required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(d) Western Massachusetts Electric Company

Certification of David R. McHale, Senior Vice President and Chief Financial Officer of WMECO required by Rule 13a – 14(a)/15d – 14(a) of the Securities Exchange Act of 1934, as amended, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

*32 Section 1350 Certificates

(a) Northeast Utilities

Certification of Charles W. Shivery, Chairman, President and Chief Executive Officer of Northeast Utilities, and David R. McHale, Senior Vice President and Chief Financial Officer of Northeast Utilities, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(b) The Connecticut Light and Power Company

Certification of Cheryl W. Grisé, Chief Executive Officer of CL&P, and David R. McHale, Senior Vice President and Chief Financial Officer of CL&P, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(c) Public Service Company of New Hampshire

Certification of Cheryl W. Grisé, Chief Executive Officer of PSNH, and David R. McHale, Senior Vice President and Chief Financial Officer of CL&P, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

(d) Western Massachusetts Electric Company

Certification of Cheryl W. Grisé, Chief Executive Officer of WMECO, and David R. McHale, Senior Vice President and Chief Financial Officer of CL&P, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, dated March 16, 2005

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles W. Shivery, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Northeast Utilities (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Charles W. Shivery and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of The Connecticut Light and Power Company (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Public Service Company of New Hampshire (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Western Massachusetts Electric Company (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

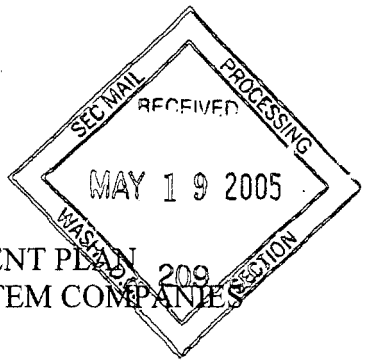
/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 10.18.7



AMENDMENT NO. 7 TO
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
FOR OFFICERS OF NORTHEAST UTILITIES SYSTEM COMPANIES

The Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies, as amended, is further amended, effective February 1, 2005, as follows:

A. Article V of the Plan is amended to read in its entirety as follows:

V. Target Benefit

If a Participant's employment as an NU system employee terminates on or after such Participant's attainment of age 60 (or earlier, if the Board so provides pursuant to Article X) and such Participant is then entitled to receive a vested benefit under the Retirement Plan, such Participant shall be entitled to receive a benefit from the Employer under this Article having a value equal to the excess, if any, of (a) over (b), where:

1. In the case of a Participant whose participation in the Plan with respect to the Target Benefit is effective before February 1, 2005:

(a) equals a lifetime benefit in an annual amount equal to 60 percent of the Participant's Final Average Compensation multiplied by the ratio of the Participant's Credited Service at the date his or her Credited Service ends to twenty-five years (such ratio not to exceed one), which benefit shall be reduced, if payment of the Target Benefit shall commence prior to the Participant's attainment of age 65, in accordance with the factors set forth in the Retirement Plan applicable to retirement benefits of employees retiring on an early retirement date, Credited Service and age to be determined for purposes of this subsection (a) after taking into account any additions to age and/or Credited Service pursuant to any retirement incentive program; and

(b) equals the sum of (i)(A) the annual benefit payable to the Participant under the Retirement Plan plus (B) the annual Make-Whole Benefit payable to the Participant pursuant to Article IV of this Plan, both such annual benefits expressed in the normal form of benefit applicable to the Participant pursuant to the terms of the Retirement Plan (whether or not such benefit is actually paid in such form) commencing at the same time as benefits hereunder, plus (ii) the annual benefit that would be payable to the Participant if any severance benefit payable to the Participant under a severance pay plan or arrangement of the Employer, including an individual agreement between the Employer and the Participant unless the terms of such agreement specifically provide otherwise, were payable in the normal form of benefit applicable to the Participant pursuant to the terms of the Retirement Plan (using the mortality factors prescribed by the Pension Benefit Guaranty Corporation and the interest rate set forth in the

definition of "Actuarial Equivalent" in the Retirement Plan for lump sum distributions) commencing at the same time as benefits hereunder;

2. In the case of a Participant whose participation in the Plan with respect to the Target Benefit is effective on or after February 1, 2005:

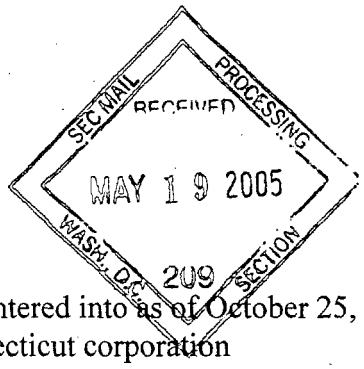
(a) equals a lifetime benefit in an annual amount equal to 50 percent of the Participant's Final Average Compensation multiplied by the ratio of the Participant's Credited Service at the date his or her Credited Service ends to twenty-five years (such ratio not to exceed one), which benefit shall be reduced, if payment of the Target Benefit shall commence prior to the Participant's attainment of age 65, in accordance with the factors set forth in the Retirement Plan applicable to retirement benefits of employees retiring on an early retirement date, Credited Service and age to be determined for purposes of this subsection (a) after taking into account any additions to age and/or Credited Service pursuant to any retirement incentive program;

(b) equals the sum of (i)(A) the annual benefit payable to the Participant under the Retirement Plan plus (B) the annual Make-Whole Benefit payable to the Participant pursuant to Article IV of this Plan, both such annual benefits expressed in the normal form of benefit applicable to the Participant pursuant to the terms of the Retirement Plan (whether or not such benefit is actually paid in such form) commencing at the same time as benefits hereunder, plus (ii) the annual benefit that would be payable to the Participant if any severance benefit payable to the Participant under a severance pay plan or arrangement of the Employer, including an individual agreement between the Employer and the Participant unless the terms of such agreement specifically provide otherwise, were payable in the normal form of benefit applicable to the Participant pursuant to the terms of the Retirement Plan (using the mortality factors prescribed by the Pension Benefit Guaranty Corporation and the interest rate set forth in the definition of "Actuarial Equivalent" in the Retirement Plan for lump sum distributions) commencing at the same time as benefits hereunder;

and the eligible spouse, if any, of such Participant shall be entitled to receive a continuation of such benefit to the extent provided in Article VII.

Notwithstanding the foregoing, if a Participant's employment as an NU system employee terminates on account of his or her Disability, such Participant's Target Benefit hereunder shall be reduced by the annual amount of benefits payable to the Participant under all long term disability plans and policies of the Employer that are attributable to contributions made by the Employer.

Exhibit 10.28



EMPLOYMENT AGREEMENT

THIS EMPLOYMENT AGREEMENT (the "Agreement") entered into as of October 25, 2004, by and between Northeast Utilities Service Company, a Connecticut corporation ("NUSCO"), with its principal office in Berlin, Connecticut, and Lawrence E. De Simone, a resident of Allentown, Pennsylvania ("Executive").

WHEREAS, the parties intend that Executive be employed as President – Competitive Group of Northeast Utilities ("NU") and hold senior executive positions with certain of the subsidiaries of NU (NU and the Affiliates, as such term is defined in Section 6.1(a), of NU being referred to collectively herein as the "Company"), and both parties desire to enter into an agreement to reflect Executive's expected contribution to the Company's business in Executive's capacities and to provide for Executive's employment by the Company, upon the terms and conditions set forth herein.

NOW, THEREFORE, the parties hereto, intending to be legally bound, hereby agree as follows:

1. **Employment**. The Company hereby agrees to employ Executive, and Executive hereby accepts such employment and agrees to perform Executive's duties and responsibilities, in accordance with the terms, conditions and provisions hereinafter set forth.

1.1. **Employment Term**. The term of Executive's employment under this Agreement shall commence as of October 25, 2004 (the "Effective Date") and shall continue until December 31, 2006, unless sooner terminated in accordance with Section 5 or Section 6 hereof, and shall automatically renew for periods of one year unless one party gives written notice to the other, at least six months prior to December 31, 2006 or at least six months prior to the end of any one-year renewal period, that the Agreement shall not be further extended. The period commencing as of the Effective Date and ending on the date on which the term of Executive's employment under the Agreement shall terminate is hereinafter referred to as the "Employment Term".

1.2. **Duties and Responsibilities**. Executive shall serve as President - Competitive Group of NU and in such other senior positions, if any, as directed by the Company's Board of Directors (the "Board") or the Board of Trustees (the "Trustees") of NU that provide Executive with duties and compensation that are substantially equivalent to Executive's current position in terms of duties and responsibilities. During the Employment Term, Executive shall perform all duties and accept all responsibilities incident to such positions as may be assigned to Executive by the Board.

1.3. **Extent of Service**. During the Employment Term, Executive agrees to use Executive's best efforts to carry out Executive's duties and responsibilities under Section 1.2 hereof and, consistent with the other provisions of this Agreement, to devote substantially all Executive's business time, attention and energy thereto. Except as provided in Section 3 hereof,

the foregoing shall not be construed as preventing Executive from making minority investments in other businesses or enterprises provided that Executive agrees not to become engaged in any other business activity which, in the reasonable judgment of the Board, is likely to interfere with Executive's ability to discharge Executive's duties and responsibilities to the Company.

1.4. **Base Salary**. For all the services rendered by Executive hereunder, NUSCO shall pay Executive a base annual salary of $475,000 ("Base Salary"), commencing on the Effective Date, payable in installments at such times as NUSCO customarily pays its other senior level executives (but in any event no less often than monthly). Executive's Base Salary shall be reviewed annually for appropriate adjustment (but shall not be reduced below that in effect on the Effective Date without Executive's written consent) by the Trustees pursuant to its normal salary review policies for senior level executives.

1.5. **Retirement and Benefit Coverages**. During the Employment Term, Executive shall be entitled to participate in all (a) employee pension and retirement plans and programs ("Retirement Plans") and (b) welfare benefit plans and programs ("Benefit Coverages"), in each case made available to the Company's senior level executives as a group or to its employees generally, as such Retirement Plans or Benefit Coverages may be in effect from time to time, including, without limitation, the Company's Supplemental Executive Retirement Plan for Officers (the "Supplemental Plan"), as to the Target Benefit, which Executive will be eligible to receive when he reaches age 60 and has five years of service with the Company.

1.6. **Reimbursement of Expenses; Vacation**. Executive shall be provided with reimbursement of expenses related to Executive's employment by NUSCO on a basis no less favorable than that which may be authorized from time to time for senior level executives as a group. In addition, Executive will be provided a lump sum payment as soon as reasonably practicable after the Effective Date, grossed-up for taxes, to cover expected costs of commissions related to sale of Executive's current home, packing and moving from Executive's current home to Connecticut, temporary living and storage of household goods, and travel between Executive's current home and Connecticut, if applicable. Executive shall also be entitled to one week of vacation in 2004 and five weeks of vacation annually thereafter and holidays in accordance with the Company's normal personnel policies for senior level executives.

1.7. **Short-Term Incentive Compensation**. Executive shall be entitled to participate in any short-term incentive compensation programs established by the Company for its senior level executives generally, depending upon achievement of certain annual individual or business performance objectives specified and approved by the Trustees (or a Committee thereof) in its sole discretion; provided, however, that Executive's "target opportunity" and "maximum opportunity" under any such program shall be at least 65% and 130% respectively of Executive's Base Salary, except that the Trustees may change these "target opportunity" and "maximum opportunity" percentages as part of a general revision of executive compensation which also applies to other senior level executives of the Company. Executive's short-term incentive compensation, either in shares of NU or cash, as applicable from time to time, shall be paid to Executive, subject to the Trustees' reasonable discretion, not later than such payments are made

to the Company's senior level executives generally. For 2004, Executive's minimum award will be at target, prorated for Executive's time in the position during 2004.

1.8. **Long-Term Incentive Compensation**. Executive shall also be entitled to participate in any long-term incentive compensation programs established by the Company for its senior level executives generally, depending upon achievement of certain business performance objectives specified and approved by the Trustees (or a Committee thereof) in its sole discretion; provided, however, that Executive's "target opportunity" and "maximum opportunity" under any such program shall be at least 150% and 300% respectively of Executive's Base Salary, except that the Trustees may change these "target opportunity" and "maximum opportunity" percentages as part of a general revision of executive compensation which also applies to other senior level executives of the Company. Executive's long-term incentive compensation, either in shares of NU, restricted stock units, options or cash, as applicable from time to time, shall be paid to Executive, subject to the Trustees' reasonable discretion, in the first quarter of 2005 and thereafter not later than such payments are made to the Company's senior level executives generally.

1.9 **Tax Preparation/Financial Planning:** Beginning in 2005, Executive will be eligible for the Senior Officers' financial planning and tax preparation benefit: reimbursement of up to $1,500 each year for professional tax return preparation and an additional $4,000 every two years for financial planning services through professionals of Executive's choice.

1.10 **Other Benefits:** Executive will be eligible to participate in the Flexible Benefits Program on Executive's first day of employment, including medical/dental coverage, life insurance, accidental death and dismemberment insurance, long-term disability insurance, expense reimbursement accounts, and qualified retirement programs including a 401(k) program, pension plan, retiree life insurance and retiree health to the extent offered to other employees of the Company. Executive will also be eligible to participate in the Deferred Compensation Program for Officers, the Employee Share Purchase Program (after one year), and the supplemental officer physical examination program.

2. **Confidential Information**. Executive recognizes and acknowledges that by reason of Executive's employment by and service to the Company before, during and, if applicable, after the Employment Term Executive has had and will continue to have access to certain confidential and proprietary information relating to the business of the Company, which may include, but is not limited to, trade secrets, trade "know-how", customer information, supplier information, cost and pricing information, marketing and sales techniques, strategies and programs, computer programs and software and financial information (collectively referred to as "Confidential Information"). Executive acknowledges that such Confidential Information is a valuable and unique asset of the Company and Executive covenants that Executive will not, unless expressly authorized in writing by the Board, at any time during the course of Executive's employment use any Confidential Information or divulge or disclose any Confidential Information to any person, firm or corporation except in connection with the performance of Executive's duties for the Company and in a manner consistent with the Company's policies regarding Confidential Information. Executive also covenants that at any time after the termination of such

employment, directly or indirectly, Executive will not use any Confidential Information or divulge or disclose any Confidential Information to any person, firm or corporation, unless such information is in the public domain through no fault of Executive or except when required to do so by a court of law, by any governmental agency having supervisory authority over the business of the Company or by any administrative or legislative body (including a committee thereof) with apparent jurisdiction to order Executive to divulge, disclose or make accessible such information, in which case Executive will inform NUSCO in writing promptly of such required disclosure, but in any event at least two business days prior to disclosure. All written Confidential Information (including, without limitation, in any computer or other electronic format) which comes into Executive's possession during the course of Executive's employment shall remain the property of the Company. Except as required in the performance of Executive's duties for the Company, or unless expressly authorized in writing by the Board, Executive shall not remove any written Confidential Information from the Company's premises, except in connection with the performance of Executive's duties for the Company and in a manner consistent with the Company's policies regarding Confidential Information. Upon termination of Executive's employment, Executive agrees immediately to return to the Company all written Confidential Information in Executive's possession

3. **Non-Competition; Non-Solicitation.**

(a) During Executive's employment by the Company and for a period of two years after Executive's termination of employment for any reason, within the Company's "service area," as defined below, Executive will not, except with the prior written consent of the Board, directly or indirectly, own, manage, operate, join, control, finance or participate in the ownership, management, operation, control or financing of, or be connected as an officer, director, employee, partner, principal, agent, representative, consultant or otherwise with, or use or permit Executive's name to be used in connection with, any business or enterprise which is engaged in any business that is competitive with any business or enterprise in which the Company is engaged ("Competitive Company"). For the purposes of this Section, "Service Area" shall mean the geographic area within the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, or any other state in which the Company, in the aggregate, generates 25% or more of its revenues in the fiscal year of NU in which Executive's termination of employment occurs. Further, for the purposes of this Section, "Competitive Company" shall mean Consolidated Edison, Inc., Energy East Corporation, Hydro-Quebec, KeySpan Energy, National Grid USA, NSTAR, or The United Illuminating Company, their assigns or successors, or any other company which in the future engages in competition with the regulated business of the Company in the Service Area. Executive acknowledges that the listed service area is the area in which the Company presently does business.

(b) The foregoing restrictions shall not be construed to prohibit the ownership by Executive of less than five percent (5%) of any class of securities of any corporation which is engaged in any of the foregoing businesses having a class of securities registered pursuant to the Securities Exchange Act of 1934 (the "Exchange Act"), provided that such ownership represents a passive investment and that neither Executive nor any group of persons including Executive in any way, either directly or indirectly, manages or exercises control of any such corporation,

guarantees any of its financial obligations, otherwise takes any part in its business, other than exercising Executive's rights as a shareholder, or seeks to do any of the foregoing.

(c) Executive further covenants and agrees that during Executive's employment by the Company and for the period of two years thereafter, Executive will not, directly or indirectly, (i) solicit, divert, take away, or attempt to solicit, divert or take away, any of the Company's "Principal Customers," defined for the purposes hereof to include any customer of the Company, from which $100,000 or more of annual gross revenues are derived at such time, or (ii) encourage any Principal Customer to reduce its patronage of the Company.

(d) Executive further covenants and agrees that during Executive's employment by the Company and for the period of two years thereafter, Executive will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring of, any person who was a managerial or higher level employee of the Company at any time during the term of Executive's employment by the Company by any employer other than the Company for any position as an employee, independent contractor, consultant or otherwise. The foregoing covenant of Executive shall not apply to any person after 12 months have elapsed subsequent to the date on which such person's employment by the Company has terminated.

(e) Nothing in this Section 3 shall be construed to prohibit Executive, if Executive is a lawyer, from being connected as a partner, principal, shareholder, associate, counsel or otherwise with another lawyer or a law firm which performs services for clients engaged in any business or enterprise that is competitive with any business or enterprise in which the Company is engaged, provided that Executive is not personally involved, directly or indirectly, in performing services for any such clients during the period specified in Section 3(a) and provided further that such lawyer or law firm takes reasonable precautions to screen Executive from participating for the period specified in Section 3(a) in the representation of any such clients. The parties agree that any such personal performance of services by Executive for any such clients during such period would create an unreasonable risk of violation by Executive of the provisions of Section 2 of this Agreement, and Executive agrees (and the Company may elect) to notify in writing any lawyer or law firm with which Executive may be connected during the period specified in Section 3(a) of Executive's Agreement as set forth herein. The parties further agree that, in addition to the nondisclosure obligations of Section 2 of this Agreement, Executive remains subject to all ethical obligations relating to confidentiality of information to the extent that Executive acted as a lawyer for the Company, but Executive's knowledge of such confidential information shall not be imputed to such other lawyer or law firm with which Executive subsequently may become connected. Executive agrees to notify the Company in writing in advance of the precautions to be taken by such lawyer or law firm to screen Executive from any representation of such competing client of such lawyer or law firm.

4. **Equitable Relief.**

(a) Executive acknowledges and agrees that the restrictions contained in Sections 2 and 3 are reasonable and necessary to protect and preserve the legitimate interests, properties, goodwill and business of the Company, that NUSCO would not have entered into this

Agreement in the absence of such restrictions and that irreparable injury will be suffered by the Company should Executive breach any of the provisions of those Sections. Executive represents and acknowledges that (i) Executive has been advised by NUSCO to consult Executive's own legal counsel in respect of this Agreement, and (ii) that Executive has had full opportunity, prior to execution of this Agreement, to review thoroughly this Agreement with Executive's counsel.

(b) Executive further acknowledges and agrees that a breach of any of the restrictions in Sections 2 and 3 cannot be adequately compensated by monetary damages. Executive agrees that the Company shall be entitled to preliminary and permanent injunctive relief, without the necessity of proving actual damages, as well as an equitable accounting of all earnings, profits and other benefits arising from any violation of Sections 2 or 3 hereof, which rights shall be cumulative and in addition to any other rights or remedies to which the Company may be entitled. In the event that any of the provisions of Sections 2 or 3 hereof should ever be adjudicated to exceed the time, geographic, service, or other limitations permitted by applicable law in any jurisdiction, it is the intention of the parties that the provision shall be amended to the extent of the maximum time, geographic, service, or other limitations permitted by applicable law, that such amendment shall apply only within the jurisdiction of the court that made such adjudication and that the provision otherwise be enforced to the maximum extent permitted by law.

(c) If Executive breaches any of Executive's obligations under Sections 2 or 3 hereof, and such breach constitutes "Cause," as defined in Section 5.3 hereof, or would constitute Cause if it had occurred during the Employment Term, the Company shall thereafter have no Target Benefit obligation pursuant to the Supplemental Plan, but shall remain obligated for the Make-Whole Benefit under the Supplemental Plan, but only to the extent not modified by the terms of this Agreement, and compensation and other benefits provided in any plans, policies or practices then applicable to Executive in accordance with the terms thereof.

(d) Executive irrevocably and unconditionally (i) agrees that any suit, action or other legal proceeding arising out of Sections 2 or 3 hereof, including without limitation, any action commenced by the Company for preliminary and permanent injunctive relief and other equitable relief, may be brought in the United States District Court for the District of Connecticut, or if such court does not have jurisdiction or will not accept jurisdiction, in any court of general jurisdiction in Hartford, Connecticut, (ii) consents to the non-exclusive jurisdiction of any such court in any such suit, action or proceeding, and (iii) waives any objection which Executive may have to the laying of venue of any such suit, action or proceeding in any such court. Executive also irrevocably and unconditionally consents to the service of any process, pleadings, notices or other papers in a manner permitted by the notice provisions of Section 10 hereof.

(e) Executive agrees that for a period of five years following the termination of Executive's employment by the Company Executive will provide, and that at all times after the date hereof the Company may similarly provide, a copy of Sections 2 and 3 hereof to any business or enterprise (i) which Executive may directly or indirectly own, manage, operate, finance, join, control or participate in the ownership, management, operation, financing, or

control of, or (ii) with which Executive may be connected as an officer, director, employee, partner, principal, agent, representative, consultant or otherwise, or in connection with which Executive may use or permit Executive's name to be used; provided, however, that this provision shall not apply in respect of Section 3 hereof after expiration of the time periods set forth therein.

5. **Termination**. The Employment Term shall terminate upon the occurrence of any one of the following events:

5.1 **Disability**. NUSCO may terminate the Employment Term if Executive is unable substantially to perform Executive's duties and responsibilities hereunder to the full extent required by the Board by reason of illness, injury or incapacity for six consecutive months, or for more than six months in the aggregate during any period of twelve calendar months; provided, however, that NUSCO shall continue to pay Executive's Base Salary until NUSCO acts to terminate the Employment Term. In addition, Executive shall be entitled to receive (i) any amounts earned, accrued or owing but not yet paid under Section 1 above and (ii) any other benefits in accordance with the terms of any applicable plans and programs of the Company. Otherwise, the Company shall have no further liability or obligation to Executive for compensation under this Agreement. Executive agrees, in the event of a dispute under this Section 5.1, to submit to a physical examination by a licensed physician selected by the Board.

5.2. **Death**. The Employment Term shall terminate in the event of Executive's death. In such event, NUSCO shall pay to Executive's executors, legal representatives or administrators, as applicable, an amount equal to the installment of Executive's Base Salary set forth in Section 1.4 hereof for the month in which Executive dies. In addition, Executive's estate shall be entitled to receive (i) any other amounts earned, accrued or owing but not yet paid under Section 1 above and (ii) any other benefits in accordance with the terms of any applicable plans and programs of the Company. Otherwise, the Company shall have no further liability or obligation under this Agreement to Executive's executors, legal representatives, administrators, heirs or assigns or any other person claiming under or through Executive.

5.3. **Cause**. NUSCO may terminate the Employment Term, at any time, for "cause" upon written notice, in which event all payments under this Agreement shall cease, except for Base Salary to the extent already accrued, and no Target Benefit shall be due under the Supplemental Plan, but Executive shall remain entitled to the Make-Whole Benefit under the Supplemental Plan, but only to the extent not modified by the terms of this Agreement, and any other benefits in accordance with the terms of any applicable plans and programs of the Company. For purposes of this Agreement, Executive's employment may be terminated for "cause" if (i) Executive is convicted of a felony, (ii) in the reasonable determination of the Board, Executive has (x) committed an act of fraud, embezzlement, or theft in connection with Executive's duties in the course of Executive's employment with the Company, (y) caused intentional, wrongful damage to the property of the Company or intentionally and wrongfully disclosed Confidential Information, or (z) engaged in gross misconduct or gross negligence in the course of Executive's employment with the Company or (iii) Executive materially breached Executive's obligations under this Agreement and shall not have remedied such breach within 30 days after receiving written notice from the Board specifying the details thereof. For purposes of

this Agreement, an act or omission on the part of Executive shall be deemed "intentional" only if it was not due primarily to an error in judgment or negligence and was done by Executive not in good faith and without reasonable belief that the act or omission was in the best interest of the Company.

5.4. **Termination Without Cause and Non-Renewal.**

(a) NUSCO may remove Executive, at any time, without cause from the position in which Executive is employed hereunder (in which case the Employment Term shall be deemed to have ended) upon not less than 60 days' prior written notice to Executive; provided, however, that, in the event that such notice is given, Executive shall be under no obligation to render any additional services to the Company and, subject to the provisions of Section 3 hereof, shall be allowed to seek other employment, and provided, further, that the Employment Term (and NUSCO's obligation to pay Base Salary) shall immediately end in the event Executive commences other employment prior to the end of the 60 day notice period. Upon any such removal or if NUSCO informs Executive that the Agreement will not be renewed after December 31, 2006 or at the end of any subsequent renewal period, or if Executive's responsibilities are significantly reduced as the result of the sale or other disposition of NUEI and unrelated to a Change of Control of Northeast Utilities, as set forth in Section 6 below, and Executive elects to terminate his employment upon the sale or other disposition of NUEI ("Constructive Termination"), Executive shall be entitled to receive, as liquidated damages for the failure of the Company to continue to employ Executive, only the amount due to Executive under the Company's then current severance pay plan for employees. No other payments or benefits shall be due under this Agreement to Executive, but Executive shall be entitled to any other benefits in accordance with the terms of any applicable plans and programs of the Company. Notwithstanding anything in this Agreement to the contrary, on or after Executive attains age 65, no action by the Company shall be treated as a removal from employment or non-renewal if on the effective date of such action Executive satisfies all of the requirements for the executive or high policy-making exception to applicable provisions of state and federal age discrimination legislation.

(b) Notwithstanding the provisions of Section 5.4(a) (other than the last sentence), in the event that Executive executes a written release upon such removal, non-renewal, or Constructive Termination, substantially in the form attached hereto as Annex 1, (the "Release"), of any and all claims against the Company and all related parties with respect to all matters arising out of Executive's employment by the Company (other than any entitlements under the terms of this Agreement or under any other plans or programs of the Company in which Executive participated and under which Executive has accrued a benefit), or the termination thereof, Executive shall be entitled to receive, in lieu of the payment described in subsection (a) hereof, which Executive agrees to waive,

(i) as liquidated damages for the failure of the Company to continue to employ Executive, a single cash payment, within 30 days after the effective date of the removal or non-renewal, equal to one times Executive's Base Compensation, as defined in Section 6.1(a)

below, which shall not constitute a "severance benefit" to Executive for purposes of the Target Benefit under the Supplemental Plan;

(ii) for a period of two years following the end of the Employment Term, Executive and Executive's spouse and dependents shall be eligible for a continuation of those Benefit Coverages, as in effect at the time of such termination or removal, and as the same may be changed from time to time, as if Executive had been continued in employment during said period or to receive cash in lieu of such benefits or premiums, as applicable, where such Benefit Coverages may not be continued (or where such continuation would adversely affect the tax status of the plan pursuant to which the Benefit Coverage is provided) under applicable law or regulations;

(iii) any other amounts earned, accrued or owing but not yet paid under Section 1 above;

(iv) any other benefits in accordance with the terms of any applicable plans and programs of the Company and a payment equal to any unused vacation;

(v) as additional consideration for the non-competition and non-solicitation covenant contained in Section 3, a single cash payment, within 30 days after the effective date of the removal or non-renewal, equal to Executive's Base Compensation, as defined in Section 6.1(a) below, which shall not constitute a "severance benefit" to Executive for purposes of the Target Benefit under the Supplemental Plan;

(vi) Under the Supplemental Plan, Executive shall be entitled to receive a Target Benefit and a Make-Whole Benefit commencing on the first day of any month following Executive's Termination, whether or not Executive has then satisfied the requirements for early, normal or deferred retirement under, or is then entitled to receive a vested benefit under, the Company's Retirement Plan, using the Termination Date as the "date of retirement" contemplated by Section IV(b) of the Supplemental Plan; Executive's years of service with the Company through the 24th month following the Termination Date shall be taken into account in determining the amount of the Target Benefit and the Make-Whole Benefit and 24 months shall be added to Executive's age for purposes of determining the reduction in such Benefits, if any, to reflect early commencement, utilizing the early commencement factor for Executive's age and years of service, each as so modified, set forth in the Company's Retirement Plan as in effect on the Termination Date or, if there is no such factor for Executive's age as so modified as of the Termination Date, a full actuarial reduction for Executive's age as so modified, as determined by the enrolled actuary for the Retirement Plan; and

5.5. **Voluntary Termination**. Executive may voluntarily terminate the Employment Term upon 30 days' prior written notice for any reason. In such event, after the effective date of such termination, no further payments shall be due under this Agreement except that Executive shall be entitled to any benefits due in accordance with the terms of any applicable plan and programs of the Company.

6. **Payments Upon a Change in Control.**

6.1. **Definitions**. For all purposes of this Section 6, the following terms shall have the meanings specified in this Section 6.1 unless the context otherwise clearly requires:

(a) "Affiliate" shall mean an "affiliate" as defined in Rule 12b-2 of the General Rules and Regulations under the Exchange Act.

(b) "Base Compensation" shall mean, for a calendar year, Executive's annualized Base Salary as would be reported for federal income tax purposes on Form W-2 for such calendar year, together with any and all salary reduction authorized amounts under any of the Company's benefit plans or programs for such calendar year, and all short-term incentive compensation at the target level to be paid to Executive in all employee capacities with the Company attributable to such calendar year and taxable in the following calendar year. "Base Compensation" shall be the higher of (i) Base Compensation for the calendar year in which occurs the Change of Control or, if no Change of Control occurs, the calendar year in which occurs the involuntary termination; or (ii) Base Compensation for the full calendar year immediately prior thereto. "Base Compensation" shall not include the value of any stock options, restricted shares, performance units, or other elements of Long-Term Incentive Compensation or any exercise thereunder.

(c) "Change of Control" shall mean the happening of any of the following:

(i) When any "person," as such term is used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), other than the Company, its Affiliates, or any Company or NU employee benefit plan (including any trustee of such plan acting as trustee), is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of NU representing more than 20% of the combined voting power of either (i) the then outstanding common shares of NU (the "Outstanding Common Shares") or (ii) the then outstanding voting securities of NU entitled to vote generally in the election of directors (the "Voting Securities"); or

(ii) Individuals who, as of the beginning of any twenty-four month period, constitute the Trustees (the "Incumbent Trustees") cease for any reason to constitute at least a majority of the Trustees or cease to be able to exercise the powers of the majority of the Trustees, provided that any individual becoming a trustee subsequent to the beginning of such period whose election or nomination for election by NU's shareholders was approved by a vote of at least a majority of the trustees then comprising the Incumbent Trustees shall be considered as though such individual were a member of the Incumbent Trustees, but excluding, for this purpose, any such individual whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of the Trustees of NU (as such terms are used in Rule 14a-11 of Regulation 14A promulgated under the Exchange Act); or

(iii) Consummation by NU of a reorganization, merger or consolidation (a "Business Combination"), in each case, with respect to which all or substantially all of the

individuals and entities who were the respective beneficial owners of the Outstanding Common Shares and Voting Securities immediately prior to such Business Combination do not, following consummation of all transactions intended to constitute part of such Business Combination, beneficially own, directly or indirectly, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation, business trust or other entity resulting from or being the surviving entity in such Business Combination in substantially the same proportion as their ownership immediately prior to such Business Combination of the Outstanding Common Shares and Voting Securities, as the case may be; or

(iv) Consummation of a complete liquidation or dissolution of NU or sale or other disposition of all or substantially all of the assets of NU other than to a corporation, business trust or other entity with respect to which, following consummation of all transactions intended to constitute part of such sale or disposition, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, is then owned beneficially, directly or indirectly, by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Common Shares and Voting Securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the Outstanding Common Shares and Voting Securities, as the case may be, immediately prior to such sale or disposition.

(d) "Termination Date" shall mean the date of receipt of a Notice of Termination of this Agreement or any later date specified therein.

(e) "Termination of Employment" shall mean the termination of Executive's actual employment relationship with the Company, including a failure to renew the Agreement after December 31, 2006 or at the end of any subsequent renewal period, in either case occasioned by the Company's action.

(f) "Termination upon a Change of Control" shall mean a Termination of Employment during the period beginning on the earlier of (a) approval by the shareholders of NU of a Change of Control or (b) consummation of a Change of Control and, in either case, ending on the second anniversary of the consummation of the transaction that constitutes the Change of Control (or if such period started on shareholder approval and after such shareholder approval the Trustees abandon the transaction, on the date the Trustees abandoned the transaction) either:

(i) initiated by the Company for any reason other than Executive's (w) disability, as described in Section 5.1 hereof, (x) death, (y) retirement on or after attaining age 65, or (z) "cause," as defined in Section 5.3 hereof, or

(ii) initiated by Executive (A) upon any failure of the Company materially to comply with and satisfy any of the terms of this Agreement, including any significant reduction by the Company of the authority, duties or responsibilities of Executive, any

reduction of Executive's compensation or benefits as in effect immediately prior to the Change of Control, or the assignment to Executive of duties which are materially inconsistent with the duties of Executive's position as defined in Section 1.2 above, or (B) if Executive is transferred, without Executive's written consent, to a location that is more than 50 miles from Executive's principal place of business immediately preceding such approval or consummation; provided, that the imposition on Executive following a Change of Control of a limitation of Executive's scope of authority such that Executive's responsibilities relate primarily to a company or companies whose common equity is not publicly held shall be considered a "significant reduction by the Company of the authority, duties or responsibilities of Executive" for the purposes hereof.

Notwithstanding the foregoing, for purposes of this definition: (i) a Termination of Employment which occurs prior to consummation of a Change of Control shall not constitute a Termination upon a Change of Control, as determined above, unless it is specifically approved by the Trustees in their sole discretion; and (ii) a Termination initiated by Executive prior to consummation of a Change of Control shall not constitute a Termination upon a Change of Control if the failure, reduction, assignment or transfer is determined by the Trustees to be unrelated to the impending Change of Control.

6.2. **Notice of Termination**. Any Termination upon a Change of Control shall be communicated by a Notice of Termination to the other party hereto given in accordance with Section 10 hereof. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific termination provision in this Agreement relied upon, (ii) briefly summarizes the facts and circumstances deemed to provide a basis for a Termination of Employment and the applicable provision hereof, and (iii) if the Termination Date is other than the date of receipt of such notice, specifies the Termination Date (which date shall not be more than 15 days after the giving of such notice).

6.3. **Payments upon Termination**. Subject to the provisions of Sections 6.6 and 6.7 hereof, in the event of Executive's Termination upon a Change of Control, the Company agrees (a) in the event Executive executes the Release required by Section 5.4(b), to pay to Executive, in a single cash payment, within thirty days after the Termination Date, two multiplied by Executive's Base Compensation and, in addition, all amounts, benefits and Benefit Coverages described in Section 5.4(b)(ii), (iii), (iv) and (v), provided that in (ii) Benefit Coverages shall continue for three years instead of two, or (b) in the event Executive fails or refuses to execute the Release required by Section 5.4(b), to pay to Executive, in a single cash payment, within thirty days after the Termination Date, the amount due under Section 5.4(a) above and, in addition, all other amounts and benefits described in Section 5.4(a).

6.4. **Supplemental Plan, Stock Option, Retiree Health Benefits, and Grants**. Subject to the provisions of Sections 6.6 and 6.7 hereof, in the event of Executive's Termination upon a Change of Control, and the execution of the Release required by Section 5.4(b):

(a) Under the Supplemental Plan, Executive shall be entitled to a Target Benefit commencing as provided below, whether or not Executive has then satisfied the requirements for early, normal or deferred retirement under, or is then entitled to receive a vested benefit under the

Company's Retirement Plan or has attained age 60, using the Termination Date as the "date of retirement" contemplated by Section IV(b) of the Supplemental Plan. There shall be an actuarial reduction in the event the Target Benefit commences prior to age 65, if at the Termination Date Executive's attained age and service for retirement benefit calculations do not total at least 85 years. The actuarial reduction shall be 2% for each year younger than age 65 to age 60, if applicable, 3% for each year younger than age 60 to age 55 and 4% for each year younger than 55, unless actuarial reduction factors more favorable to Executive are adopted in the Retirement Plan, in which case those factors shall apply. Executive's years of service with the Company through the 36th month following the Termination Date shall be taken into account in determining the amount of the Target Benefit and 36 months shall be added to Executive's age for purposes of determining Executive's eligibility for such Benefits and the actuarial reduction under the Plan as modified herein. Executive shall determine the form of payment in which the Target Benefit shall be paid, in accordance with the terms of the Supplemental Plan or may elect to receive a single sum payment equal to the then actuarial present value (computed using the 1983 GAM (50%/Male/50%/Female) Mortality Table and at an interest rate equal to the discount rate used in the Retirement Plan's previous year's FASB 87 accounting) of the amount of the Target Benefit as determined in accordance with the first three sentences of this subsection (a). Payment shall commence or be made within 30 days after the Termination Date or on any date thereafter, as specified by Executive in a written election. Such election may be made at any time and amended at any time but any election or amendment, other than one made within 30 days of the Effective Date, shall be ineffective if made within six months prior to the Termination Date. In the absence of any election or determination provided for herein, the terms of the Supplemental Plan shall govern the form and time of payment.

(b) Executive's age and years of service with the Company through the 36th month following the Termination Date shall be taken into account in determining Executive's eligibility for benefits, but not cost-sharing, under the Company's retiree health plan. For the purpose of determining such eligibility, a Termination upon a Change of Control shall be considered to be an involuntary termination.

(c) Unless the Compensation Committee of the Northeast Utilities Board of Trustees is comprised of the same members as those on the Committee immediately before the Change of Control and determines otherwise, (i) all stock option grants previously granted to Executive, to the extent not already vested prior to such occurrence, shall be fully vested and immediately exercisable as if Executive had satisfied all requirements as to exercise, including the right of exercise, where appropriate, within 36 months of such occurrence and, if the Change of Control results in the Voting Securities of NU ceasing to be traded on a national securities exchange or though the national market system of the National Association of Securities Dealers Inc., the value of a share of stock on the day the option is exercised shall be deemed to be the closing price on the day such Voting Securities cease trading; and (ii) if NU is not the surviving corporation (or survives only as a subsidiary of another corporation), those portions of any such options that have not been exercised shall be assumed by, or replaced with comparable options or rights by, the surviving corporation. Notwithstanding the foregoing, such Committee (if comprised of the same members as those on the Committee immediately before the Change of Control) may require Executive to surrender the remainder of any or all such options, in each

case in exchange for a payment by the Company, in cash or common shares as determined by the Committee, in an amount equal to the amount by which the then fair market value of the common shares subject to such option exceeds the exercise price per share of such option, or, after giving Executive an opportunity to exercise such option, terminate the option at such time as the Committee deems appropriate.

6.5. **Non-Exclusivity of Rights**. Nothing in this Agreement shall prevent or limit Executive's continuing or future participation in or rights under any benefit, bonus, incentive or other plan or program provided by the Company and for which Executive may qualify; provided, however, that if Executive becomes entitled to and receives all of the payments provided for in this Agreement, Executive hereby waives Executive's right to receive payments under any severance plan or similar program applicable to all employees of the Company.

6.6. **Certain Increase in Payments.**

(a) Anything in this Agreement to the contrary notwithstanding, in the event that it shall be determined that any payment or distribution by the Company to or for the benefit of Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (the "Payment"), would constitute an "excess parachute payment" within the meaning of Section 280G of the Internal Revenue Code of 1986, as amended (the "Code"), Executive shall be paid an additional amount (the "Gross-Up Payment") such that the net amount retained by Executive after deduction of any excise tax imposed under Section 4999 of the Code, and any federal, state and local income and employment tax and excise tax imposed upon the Gross-Up Payment shall be equal to the Payment. For purposes of determining the amount of the Gross-Up Payment, Executive shall be deemed to pay federal income tax and employment taxes at the highest marginal rate of federal income and employment taxation in the calendar year in which the Gross-Up Payment is to be made and state and local income taxes at the highest marginal rate of taxation in the state and locality of Executive's residence on the Termination Date, net of the maximum reduction in federal income taxes that may be obtained from the deduction of such state and local taxes.

(b) All determinations to be made under this Section 6 shall be made by the Company's independent public accountant immediately prior to the Change of Control (the "Accounting Firm"), which firm shall provide its determinations and any supporting calculations both to the Company and Executive within 10 days of the Termination Date. Any such determination by the Accounting Firm shall be binding upon the Company and Executive. Within five days after the Accounting Firm's determination, the Company shall pay (or cause to be paid) or distribute (or cause to be distributed) to or for the benefit of Executive such amounts as are then due to Executive under this Agreement.

(c) In the event that upon any audit by the Internal Revenue Service, or by a state or local taxing authority, of the Payment or Gross-Up Payment, a change is finally determined to be required in the amount of taxes paid by Executive, appropriate adjustments shall be made under this Agreement such that the net amount which is payable to Executive after

taking into account the provisions of Section 4999 of the Code shall reflect the intent of the parties as expressed in subsection (a) above, in the manner determined by the Accounting Firm.

(d) All of the fees and expenses of the Accounting Firm in performing the determinations referred to in subsections (b) and (c) above shall be borne solely by the Company. The Company agrees to indemnify and hold harmless the Accounting Firm of and from any and all claims, damages and expenses resulting from or relating to its determinations pursuant to subsections (b) and (c) above, except for claims, damages or expenses resulting from the gross negligence or willful misconduct of the Accounting Firm.

6.7 **Changes to Sections 6.3 and 6.4**. The payments, benefits and other compensation provided under Sections 6.3 and 6.4 may be revised, in the sole discretion of the Board, after the expiration of two years following written notice to Executive of the Board's intention to do so and the changes to be made; provided, however, that no revision may be made that would reduce the payments, benefits and other compensation below those provided under Section 5.4 in the event Executive's employment is terminated without cause or this Agreement is not renewed; and provided, further, that no such notice may be given and no such revision may become effective following a Change of Control. Notice under this Section 6.7 shall not constitute a non-renewal or removal of Executive, nor shall any such actual revision be grounds for a determination that this Agreement is not being renewed or that Executive has been removed, for purposes of Section 5.4.

7. **Survivorship**. The respective rights and obligations of the parties under this Agreement shall survive any termination of Executive's employment to the extent necessary to the intended preservation of such rights and obligations.

8. **Mitigation**. Executive shall not be required to mitigate the amount of any payment or benefit provided for in this Agreement by seeking other employment or otherwise and there shall be no offset against amounts due Executive under this Agreement on account of any remuneration attributable to any subsequent employment that Executive may obtain.

9. **Arbitration; Expenses**. In the event of any dispute under the provisions of this Agreement other than a dispute in which the primary relief sought is an equitable remedy such as an injunction, the parties shall be required to have the dispute, controversy or claim settled by arbitration in the City of Hartford, Connecticut in accordance with National Rules for the Resolution of Employment Disputes then in effect of the American Arbitration Association, before a panel of three arbitrators, two of whom shall be selected by the Company and Executive, respectively, and the third of whom shall be selected by the other two arbitrators. Any award entered by the arbitrators shall be final, binding and nonappealable (except as provided in Section 52-418 of the Connecticut General Statutes) and judgment may be entered thereon by either party in accordance with applicable law in any court of competent jurisdiction. This arbitration provision shall be specifically enforceable. The arbitrators shall have no authority to modify any provision of this Agreement or to award a remedy for a dispute involving this Agreement other than a benefit specifically provided under or by virtue of the Agreement. If Executive prevails on any material issue which is the subject of such arbitration or lawsuit, the Company shall be

responsible for all of the fees of the American Arbitration Association and the arbitrators and any expenses relating to the conduct of the arbitration (including the Company's and Executive's reasonable attorneys' fees and expenses). Otherwise, each party shall be responsible for its own expenses relating to the conduct of the arbitration (including reasonable attorneys' fees and expenses) and shall share the fees of the American Arbitration Association.

10. **Notices.** All notices and other communications required or permitted under this Agreement or necessary or convenient in connection herewith shall be in writing and shall be deemed to have been given when hand delivered or mailed by registered or certified mail, as follows (provided that notice of change of address shall be deemed given only when received):

If to the Company, to:

Northeast Utilities Service Company
P.O. Box 270 Hartford, CT 06141-0270
Attention: Senior Vice President, Secretary and General Counsel

If to Executive, to:

Lawrence E. De Simone
3610 W. Chew Street
Allentown, PA 18104

or to such other names or addresses as the Company or Executive, as the case may be, shall designate by notice to each other person entitled to receive notices in the manner specified in this Section.

11. **Contents of Agreement; Amendment and Assignment.**

(a) This Agreement sets forth the entire understanding between the parties hereto with respect to the subject matter hereof and cannot be changed, modified, extended or terminated except upon written amendment approved by the Board and executed on its behalf by a duly authorized officer and by Executive.

(b) All of the terms and provisions of this Agreement shall be binding upon and inure to the benefit of and be enforceable by the respective heirs, executors, administrators, legal representatives, successors and assigns of the parties hereto, except that the duties and responsibilities of Executive under this Agreement are of a personal nature and shall not be assignable or delegable in whole or in part by Executive. The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation, reorganization or otherwise) to all or substantially all of the business or assets of the Company, by agreement in form and substance satisfactory to Executive, expressly to assume and agree to perform this Agreement in the same manner and to the extent the Company would be required to perform if no such succession had taken place.

12. **Severability**. If any provision of this Agreement or application thereof to anyone or under any circumstances is adjudicated to be invalid or unenforceable in any jurisdiction, such invalidity or unenforceability shall not affect any other provision or application of this Agreement which can be given effect without the invalid or unenforceable provision or application and shall not invalidate or render unenforceable such provision or application in any other jurisdiction. If any provision is held void, invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances.

13. **Remedies Cumulative; No Waiver**. No remedy conferred upon a party by this Agreement is intended to be exclusive of any other remedy, and each and every such remedy shall be cumulative and shall be in addition to any other remedy given under this Agreement or now or hereafter existing at law or in equity. No delay or omission by a party in exercising any right, remedy or power under this Agreement or existing at law or in equity shall be construed as a waiver thereof, and any such right, remedy or power may be exercised by such party from time to time and as often as may be deemed expedient or necessary by such party in its sole discretion.

14. **Beneficiaries/References**. Executive shall be entitled, to the extent permitted under any applicable law, to select and change a beneficiary or beneficiaries to receive any compensation or benefit payable under this Agreement following Executive's death by giving the Company written notice thereof. In the event of Executive's death or a judicial determination of Executive's incompetence, reference in this Agreement to Executive shall be deemed, where appropriate, to refer to Executive's beneficiary, estate or other legal representative.

15. **Miscellaneous**. All section headings used in this Agreement are for convenience only. This Agreement may be executed in counterparts, each of which is an original. It shall not be necessary in making proof of this Agreement or any counterpart hereof to produce or account for any of the other counterparts.

16. **Withholding**. The Company may withhold from any payments under this Agreement all federal, state and local taxes as the Company is required to withhold pursuant to any law or governmental rule or regulation. Executive shall bear all expense of, and be solely responsible for, all federal, state and local taxes due with respect to any payment received under this Agreement.

17. **Governing Law**. This Agreement shall be governed by and interpreted under the laws of the State of Connecticut without giving effect to any conflict of laws provisions.

18. **Adoption by Affiliates; Obligations**. The obligations under this Agreement shall, in the first instance, be paid and satisfied by NUSCO; provided, however, that NUSCO will use its best efforts to cause NU and each unregulated entity in which NU (or its successors or assigns) now or hereafter holds, directly or indirectly, more than a 50 percent voting interest to approve and adopt this Agreement and, by such approval and adoption, to be bound by the terms hereof as though a signatory hereto. If NUSCO shall be dissolved or for any other reason shall fail to pay and satisfy the obligations, each individual such unregulated entity thereafter shall be jointly and

severally liable to pay and satisfy the obligations to Executive. Any provisions of this Agreement to the contrary notwithstanding, this Agreement shall neither apply to, nor be adopted by, The Connecticut Light and Power Company, Yankee Gas Services Company, Western Massachusetts Electric Company or Public Service Company of New Hampshire (collectively the "regulated entities") nor shall the regulated entities be jointly or severally liable to Executive for any obligations hereunder.

19. **Establishment of Trust**. The Company may establish an irrevocable trust fund pursuant to a trust agreement to hold assets to satisfy any of its obligations under this Agreement. Funding of such trust fund shall be subject to the Board's discretion, as set forth in the agreement pursuant to which the fund will be established.

IN WITNESS WHEREOF, the undersigned, intending to be legally bound, have executed this Agreement as of the date first above written.

LAWRENCE E. DE SIMONE	**NORTHEAST UTILITIES SERVICE COMPANY**
/s/ Lawrence E. DeSimone	By /s/ Gregory B. Butler
Date: November 10, 2004	Its Senior VP, Secretary and General Counsel
	Date: November 10, 2004

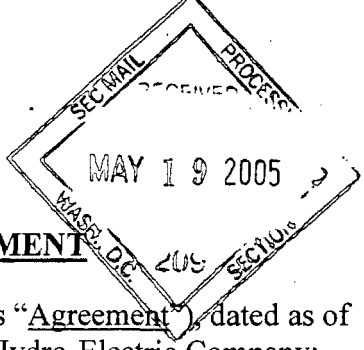


Exhibit 10.29

TRANSMISSION OPERATING AGREEMENT

This Transmission Operating Agreement (this "TOA" or this "Agreement"), dated as of February 1, 2005, is made and entered into by and among Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company; Central Maine Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; Florida Power & Light Company; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company as agent for: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Power and Electric Company; Holyoke Water Power Company; and Public Service Company of New Hampshire; Norwood Municipal Light Department; Town of Reading Municipal Light Department; Taunton Municipal Lighting Plant; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc; and Vermont Electric Power Company, Inc. (herein collectively referred to as the "Initial Participating Transmission Owners"), and the Initial Participating Transmission Owners along with any Additional Participating Transmission Owners (as defined in Section 11.05 of this Agreement), are collectively referred to herein as the "PTOs" and individually each is referred to as a "PTO"), and ISO New England Inc.("ISO"), a Delaware corporation (all PTOs and the ISO are collectively referred to herein as the "Parties").

WHEREAS, each of the PTOs owns and/or operates certain transmission facilities that are interconnected with the transmission facilities of certain other PTOs within the New England Transmission System or otherwise provides transmission service within the New England Transmission System;

WHEREAS, the ISO is a regional transmission organization ("RTO") authorized by the Federal Energy Regulatory Commission ("FERC") to exercise the functions required of RTOs pursuant to FERC's Order No. 2000 ("Order 2000") and FERC's RTO regulations;

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO Open Access Transmission Tariff (the "ISO OATT") of non-discriminatory, open access transmission services over the transmission facilities of the PTOs ("Transmission Service");

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of the PTOs in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of the PTOs, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over the PTOs' transmission facilities;

WHEREAS, in accordance with the terms set forth herein, the PTOs desire for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the PTOs' Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000;

WHEREAS, the PTOs will, among other things, continue to own, physically operate, and maintain their Transmission Facilities and Local Control Centers; and

WHEREAS, each PTO reserves the right to transfer certain rights and obligations to an Independent Transmission Company in accordance with Attachment M to the ISO OATT.

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, each of the PTOs and the ISO agree as follows:

ARTICLE I
DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Agreement;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with and as an integral part of this Agreement to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise

applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Agreement;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any Person (as hereinafter defined) includes such Person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsperson hereof or thereof.

ARTICLE II

TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to any PTO, the transmission facilities over which the ISO shall exercise Operating Authority in accordance with the terms set forth herein shall be:

(a) those facilities of such PTO listed in Schedule 2.01(a) (hereinafter "Category A Facilities"), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of such PTO listed in Schedule 2.01(b) (hereinafter "Category B Facilities"), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

I those transmission facilities of such PTO within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter "Local Area Facilities"), provided that any excluded facilities of such PTO listed on Schedule 4.01(d) shall not be Local Area Facilities.

(d) As to each PTO, the transmission facilities included on any of the lists of the Category A Facilities or the Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, as of the Operations Date may be redesignated on another of these two lists, deleted from such list, or redesignated as a Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and all PTOs shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and the PTO or PTOs owning the transmission facilities; or

(iii) where the operational characteristics of a transmission facility have been materially modified after the Operations Date (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as Category A Facilities, Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities

specifically designated as Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have Category A Facilities connected to the lower voltage side of the transformer; all transformers that require a Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any Category B Facilities and no Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such Category B Facilities.

(iii) Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and a PTO or PTOs owning a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

(f) Collectively, all Category A Facilities, Category B Facilities, and Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(g) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 **New and Acquired Transmission Facilities and Transmission Upgrades.**

(a) Any New Transmission Facility, any Transmission Upgrade, and any Acquired Transmission Facility shall be considered a "Transmission Facility" under this Agreement once it is placed into commercial operation by the applicable PTO(s); shall be designated as a Category A Facility, Category B Facility, or Local Area Facility in accordance with Section 2.01(e) unless otherwise agreed by the ISO and the PTO(s) owning the Transmission Facility; and shall be subject to the Operating Authority of the ISO in accordance with the terms of this Agreement.

(b) The designation of an Acquired Transmission Facility as a Category A, Category B or Local Area Facility shall not require the abrogation or modification of existing contractual arrangements for such Acquired Transmission Facility.

(c) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 **Merchant Facilities.** The terms and conditions under which a PTO, an Affiliate of a PTO, or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this Agreement, it being understood that such entities shall enter into operating agreements relating to their Merchant Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of a PTO, the Affiliate of a PTO, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System.

2.04 **Excluded Assets.** The "Excluded Assets" of a PTO shall consist of those assets and/or facilities of a PTO set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over a PTO's Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of a PTO's Transmission Facilities or any other asset of a PTO. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Any assets, facilities, and/or portions of facilities owned by such PTO that are connected with or associated with those facilities defined as Category A Facilities, Category B Facilities or Local Area Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities of such PTO, (2) arising under any contracts or tariffs of such PTO and relating to services provided prior to the beginning of the Term, (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC, or (4) relating to a Grandfathered Transmission Agreement;

(iii) any rights, ownership, title or interest any PTO may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO's Operating Authority in accordance with practice prior to the Operations Date and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of the PTOs related in any manner to Transmission Facilities unless such PTO agrees to assign or transfer such contracts to the ISO, provided that the PTOs shall exercise their rights and responsibilities under Grandfathered Transmission Agreements in accordance with Section 3.11 and the applicable provisions of this Agreement;

(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for facilities specifically defined as Category A Facilities, Category B Facilities or Local Area Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of the PTO and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage a PTO's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Any assets or facilities of such PTO that are not specifically defined as Category A Facilities, Category B Facilities or Local Area Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by the PTO;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of such PTO and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest any PTO may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of the PTOs unless such PTO agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in each PTO's real property, provided that nothing in this Section 2.04 shall: (a) supersede the rights and obligations of the Parties as set forth in the Control Center Lease or Back-up Control Center Lease or (b) restrict the PTOs from conveying interests in real property in any future written agreement into which the ISO and any PTO or group of PTOs may, in their sole discretion, enter.

2.05 **Connection with Non-Parties.**

(a) On or after the Operations Date, each PTO shall connect its Transmission Facilities with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to a PTO's Transmission Facilities to the extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission facilities shall be subject to the conditions associated with the PTOs' obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit under the Interconnection Standard); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(a)(ii) below, each PTO shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, a PTO shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to such PTO and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Unit to any Transmission Facility of a PTO the Interconnection Agreement shall be a three-party agreement among the PTO, the ISO, and the interconnecting non-Party based on the pro forma Large Generator Interconnection Agreement in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of a PTO, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs, acting jointly in accordance with the Disbursement Agreement among them, may initiate a filing to amend the pro forma Large Generator Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such filing the views of the ISO and the PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the PTOs' position on any financial obligations of the PTOs or the interconnecting non-Party, and any provisions related to physical impacts of the interconnection on the PTOs' Transmission Facilities or other assets. If the PTO, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large Generator Interconnection

Agreement for a Large Generating Unit, or any amendments to such an Interconnection Agreement, then the PTO and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent the PTO, the ISO and such interconnecting non-Party cannot agree to proposed variations from the pro forma Large Generator Interconnection Agreement applicable to a specific Large Generating Unit or cannot otherwise agree to the terms and conditions of the Interconnection Agreement for such Large Generating Unit, or any amendments to such an Interconnection Agreement, then the PTO and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to such PTO's Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of the PTO, and any provisions related to physical impacts of the interconnection on the PTO's Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to the PTO's position on such terms and conditions.

The costs of interconnection facilities shall be allocated in the manner specified in the ISO OATT.

(b) Each PTO shall also connect its Transmission Facilities with the facilities of any entity that is not a Party upon satisfaction of the "Elective Transmission Upgrade" provisions of the ISO OATT, provided that the PTO shall only connect the facilities of such entity (the "Elective Transmission Upgrade Applicant") upon satisfaction of the following conditions:

(i) The Elective Transmission Upgrade Applicant shall enter into an Interconnection Agreement with the affected PTO(s) and, to the extent necessary and appropriate, enter into support agreements with the affected PTO(s), provided that the Elective Transmission Upgrade Applicant may request, upon providing the security, credit assurances, and/or deposits required by the affected PTO, the filing with the Commission by the PTO of unexecuted Interconnection Agreements and support agreements.

(ii) The Elective Transmission Upgrade Applicant shall obtain all necessary legal rights and approvals for the construction and maintenance of the upgrade and shall cooperate with the PTO(s) in obtaining all necessary legal rights and approvals for the construction and maintenance of additions or modifications, if any, required in conjunction with the upgrade.

(iii) The Elective Transmission Upgrade Applicant shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** Each PTO shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such PTO's Transmission Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by the PTO which may have a significant effect on the stability, reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such PTO submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies the PTO in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, the PTO shall be free to proceed. If the ISO notifies the PTO that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, the PTO shall not proceed to implement such plan unless the PTO takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by a PTO through condemnation or otherwise through the power of eminent domain, (i) such PTO shall provide the ISO with written notice of such process, (ii) such PTO shall, at its cost, direct any litigation or proceeding regarding such condemnation or eminent domain matter, (iii) such PTO shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to such PTO without any claim to such award by the ISO.

ARTICLE III
OPERATING AUTHORITY

3.01 **Grant of Operating Authority.**(a) Subject to the terms set forth in this Agreement, including Article III and Article X hereof, effective as of the Operations Date, and with respect to Publicly-Owned PTOs, to the extent permitted by, or in a manner consistent with the laws of any State governing the organization or operation of such Publicly-Owned PTOs, each PTO hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission

Facilities, including provision of Transmission Service over the Transmission Facilities under the ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over such PTOs' Transmission Facilities in accordance with this Agreement.

(b) The grant by the PTOs to the ISO and the assumption by the ISO of Operating Authority over the Transmission Facilities are solely for the purposes of allowing the ISO to fulfill the functions of an RTO as specified herein (including provision of Transmission Service under the ISO OATT) and do not constitute an assumption by the ISO of any liabilities with respect to the Transmission Facilities except as otherwise specifically provided herein (including as provided in Article IX of the Agreement).

(c) Nothing herein or elsewhere contained shall be construed as requiring or effecting a transfer of any PTO's responsibility (or the assumption thereof by the ISO) for the physical control of the Transmission Facilities, including the physical operation, repair, maintenance and replacement of such Transmission Facilities, or as conveying to the ISO: (x) any right, ownership, title or interest in or to a PTO's Transmission Facilities; (y) any right of access to any PTO's real property, except as specified in Section 3.02(i); or (z) any rights or authority with respect to a PTO's Excluded Assets, except as specifically provided herein.

3.02 **Definition of ISO Operating Authority.** Consistent with the provisions of this Agreement, including Section 3.02(a) below, "Operating Authority" shall mean those functions set forth in Sections 3.02, 3.03, and 3.08 and those responsibilities set forth in Section 3.05, and shall not include those rights, responsibilities and functions set forth in Sections 3.06 and 3.07. Subject to the first sentence of this Section 3.02, the ISO shall exercise such Operating Authority in accordance with applicable Operating Procedures as specified in Section 3.02(d) below.

(a) The ISO shall perform the following functions with respect to each PTO's Transmission Facilities, consistent with applicable NERC/NPCC Requirements and other applicable regulatory standards, including (as needed) issuing instructions to, or coordinating with, each PTO's Local Control Center(s):

(i) centrally dispatch generation (and dispatchable and interruptible load) and implement real-time balancing, including meeting NERC control performance criteria;

(ii) determine Operating Limits based on forecasted or real-time system conditions and in accordance with the facility ratings established by the PTOs in collaboration with the ISO pursuant to Section 3.06;

(iii) take such actions as may be necessary to plan and maintain short-term (including real-time) reliability and system security (including curtailment of external transactions in accordance with FERC-accepted or -approved Market Rules and the applicable transmission tariff or transmission agreement);

(iv) consistent with the ISO Information Policy, exchange security information with applicable PTOs, non-PTO transmission operators and other neighboring systems and regional entities; and

(v) provide for an ISO Control Center and an independent Back-up Control Center, as the ISO deems necessary to comply with applicable NERC/NPCC Requirements and any applicable regulatory requirement.

(b) The ISO shall receive, confirm and schedule External Transactions for the New England Transmission System; enter into Coordination Agreements and operating arrangements with the operators of neighboring Control Areas; coordinate system operation and emergency procedures with neighboring Control Areas; and administer each PTO's Interconnection Agreements with neighboring Control Areas and scheduling provisions of the tariff(s) applicable to External Transactions, in accordance with the terms of those agreements and tariffs; provided that as of the Operations Date, the applicable agreements and tariffs shall be set forth in Schedule 3.02(b).

(c) The ISO shall act as the Reliability Authority for the New England Transmission System. The ISO may intercede and direct appropriate near-term operational actions in order to protect reliability, provided that nothing in this Section 3.02(c) shall require any PTO to undertake an action contrary to applicable Law or shall limit the right of each PTO pursuant to Section 3.07 to take any action(s) that it deems necessary to prevent loss of human life, injury to persons and/or damage to property.

(d) The ISO shall utilize the Operating Procedures relating to the exercise of Operating Authority over the Transmission Facilities. The Operating Procedures shall initially consist of the Operating Procedures in existence on the Operations Date (hereinafter "Existing Operating Procedures"). Such Existing Operating Procedures shall consist of those Operating Procedures listed in Schedule 3.02(d). The ISO shall develop any modifications to Operating Procedures (including Existing Operating Procedures) and any new Operating Procedures that it may deem necessary or appropriate: (i) in coordination with those PTOs (or their Local Control Centers, as applicable) whose Transmission Facilities will be operated in accordance with such Operating Procedures so as to ensure that that the PTO's (or Local Control Center's) knowledge of their Transmission Facilities is given due consideration in the development or modification of the transmission-related portions of such Operating Procedures and (ii) in consultation with other stakeholders. The ISO shall have the authority to modify Operating Procedures or develop new Operating Procedures without such coordination or consultation when the ISO does not have sufficient time to undertake such coordination or consultation due to emergent and unanticipated circumstances. In the event that the ISO and the applicable PTO(s) disagree about modifications to the transmission-related portions of Operating Procedures or any new Operating Procedures related to the operation of such PTOs' Transmission Facilities, the affected PTO(s) will have the opportunity to submit the dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Pending such resolution, the ISO shall have the authority, as the system operator with ultimate authority for the real-time operation of the New

England Transmission System, to implement any such new Operating Procedures or modified Operating Procedures. Notwithstanding anything in the foregoing, Operating Procedures related to the establishment of ratings for a PTO's New Transmission Facilities and Acquired Transmission Facilities or related to changes to existing ratings of a PTO's Transmission Facilities (collectively "Rating Procedures") shall be developed and placed into effect pursuant to Section 3.06(a)(v).

To the extent the PTOs will be required to physically operate their Transmission Facilities in accordance with any operational documents in effect as of the Operations Date or as subsequently developed or amended by the ISO (other than the Operating Procedures), the ISO shall develop such operational documents and amendments thereto in coordination with those PTOs (or their Local Control Centers, as applicable) whose Transmission Facilities will be operated in accordance with such documents, provided that stakeholders shall have the right to consult in the development of such documents, subject to any limitations associated with the confidential nature of such documents consistent with confidentiality, that the ISO will have the right to place such operating documents into effect in the event of a dispute concerning such documents, and that the affected PTO(s) shall have the right to submit any such dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Any such coordination between any PTO and the ISO pursuant to this Section 3.04(d) shall be subject to applicable standards of conduct consistent with FERC Order No. 889.

(e) The ISO shall seek agreement with the PTOs, where time limitations do not make it impracticable to do so, on real-time operational decisions affecting the Transmission Facilities not otherwise specified in the Operating Procedures developed in accordance with Section 3.02(d). In the absence of such agreement, or if time limitations do not permit reaching agreement, the ISO shall implement its operational decision. If such ISO decision is disputed, the ISO's position shall control pending resolution of the dispute.

(f) The ISO shall develop, maintain, and, if needed, implement the System Restoration Plan for the New England Transmission System, which shall include the existing PTO Local Restoration Plans. The ISO shall develop any modifications to the System Restoration Plan in consultation with the PTOs and shall incorporate into the System Restoration Plan any modifications developed by each PTO to their PTO Local Restoration Plans, provided that any modifications to the PTO Local Restoration Plans are subject to the ISO's approval in order to coordinate and promote the reliability of the Restoration Plans.

(g) The ISO shall coordinate voltage and reactive dispatch of facilities to the extent normal schedules are unable to be maintained by Local Control Centers.

(h) The ISO shall direct the implementation of emergency procedures, including Load Shedding and voltage reduction, in coordination with the PTO Local Control Centers.

(i) The ISO shall have the authority to perform the following tasks in relation to compliance with current or future PTO responsibilities:

(i) perform all compliance and monitoring responsibilities of the ISO, including the issuance of sanction letters, with respect to existing or successor NERC or NPCC compliance programs associated with standards, criteria and measurements for which the PTOs are responsible and accountable to the ISO. To the extent that the ISO receives a sanction letter from NERC or NPCC that is substantially related to the actions of a PTO, the ISO may issue a sanction letter to such PTO;

(ii) perform all compliance and monitoring responsibilities of the ISO associated with Operating Procedures relating to standards, criteria and measurements that the PTOs are responsible for and accountable to the ISO. Such responsibilities shall include audits of PTOs for compliance with Operating Procedures to the extent the ISO determines such audits are necessary, and the issuance of sanction letters;

(iii) perform periodic audits of each Local Control Center's and PTO's performance of the functions listed in Sections 3.06 (a)(i), (ii), (iv), (vi), (vii), (viii), (ix) and (x) in accordance with applicable Operating Procedures and applicable reliability standards, including audits to monitor compliance of the Local Control Center (and PTO employees interacting with the Local Control Centers) with the ISO Information Policy and applicable standards of conduct consistent with FERC Order No. 889 in performing these functions. Such Local Control Center audits shall generally be conducted no more frequently than once every three years, provided that the ISO shall have the authority to conduct an audit more frequently if it determines that circumstances so require.

All audits conducted pursuant to this Section 3.02(i) shall be conducted by the ISO or by an independent third party, with expenses of the ISO (or the third-party auditor) borne by the ISO and recovered through its administrative tariff. The PTO shall bear its own expenses in complying with the audit. Such audits shall be conducted during normal business or operational hours and with reasonable notice. The general scope of each audit and the general process for conducting the audit will be discussed with the affected PTO in advance. Nothing in this Section 3.02(i) shall imply that a sanction letter shall include any financial or other penalties. Nothing in this Section 3.02(i) shall limit the right of the ISO to separately file proposals at FERC to assess financial or other penalties against any entity or shall limit the right of the PTOs to comment on or protest any such proposals.

(j) In addition to the functions set forth in Sections 3.02(a) - (i), Operating Authority shall also consist of the following functions that the ISO shall perform with respect to each PTO's Category A Facilities; provided, however, that the ISO (in the absence of the PTO's consent) is not authorized to perform such functions with respect to any PTO's Category B Facilities or Local Area Facilities, unless the outages of such facilities reasonably could be expected to result in a violation of reliability criteria:

(i) monitor and control, in accordance with the facility ratings established by the PTOs in collaboration with the ISO pursuant to Section 3.06, on a real-time basis, power flows on the system, voltage and system frequency; and

(ii) coordinate with the Local Control Centers on the settings for dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other similar dynamic equipment that affects power flows, and approve or direct changes to such settings.

(k) If at any time, any Party provides notice to all of the other Parties that it believes NERC and NPCC documents that are not NERC/NPCC Requirements have been modified so as to expand the scope of the functions to be performed by the ISO or the PTOs, the Parties shall consider in good faith changes to this Agreement that will allow the Parties to follow such guidelines; provided, however, that, the Parties shall have no obligation to agree to such changes. If the Parties cannot agree to such changes, the dispute resolution procedures of Section 11.14 shall be utilized. Nothing in this Section 3.02(k) shall be construed to excuse any Party from complying with applicable NERC/NPCC Requirements.

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to all Transmission Service requests and requests to be interconnected to the New England Transmission System under the ISO OATT, including the Local Service Schedules. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests; provided, however, that: (A) the ISO shall consult with a PTO prior to completion of system impact studies and facilities studies in connection with requests that affect such PTO's Transmission Facilities and shall include in any such studies the PTO's reasonable estimates of the costs of upgrades to such PTO's Transmission Facilities needed to implement the conclusions of such studies and the PTO's reasonable anticipated schedule for the construction of such upgrades; (B) nothing in this Agreement shall preclude the ISO from entering into an agreement(s) with a PTO for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies in connection with requests that affect such PTO's Transmission Facilities; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the

interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the PTO's reasonable estimates of the costs of upgrades to such PTO's Transmission Facilities needed to implement the conclusions of such studies and the PTO's reasonable anticipated schedule for the construction of such upgrades; and (D) each PTO shall, upon request by the ISO, conduct any necessary studies related to such PTO's Transmission Facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.09 of this Agreement.

(ii) The ISO shall forward to the appropriate PTO(s) applications for Local Service. The ISO shall review applications for Local Service or requests to be interconnected to the New England Transmission System to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service. The PTO shall be responsible for reviewing and responding to requests for Local Service not having an impact on facilities used for the provision of regional transmission service and for interconnections not having an impact on facilities used for the provision of regional transmission service, and shall perform all system impact studies and facilities studies regarding such requests; provided, however, that the PTO shall consult with the ISO prior to completion of such system impact studies and facilities studies and further provided that the ISO will use reasonable efforts to assist the PTO and interconnecting party in resolving disputes arising regarding the performance of such studies. The PTOs shall provide the ISO with information necessary to evaluate any such dispute in accordance with Section 11.09 of this Agreement, and shall include provisions in each of their study agreements providing for reimbursement of the ISO's costs incurred in these efforts.

(iii) The ISO shall calculate the TTC and ATC for all interties on the New England Transmission System and determine the TTC and ATC calculation methodologies for interties on the New England Transmission System (consistent with applicable NERC/NPCC Requirements and applicable regulatory standards), provided that modifications to calculation methodologies as they exist on the Operations Date shall be developed by the ISO in consultation with the PTOs and other interested stakeholders. To the extent that TTC and ATC on a PTO's Local Network must be calculated in connection with the provision of Local Service, then the PTO shall calculate such TTC and ATC.

(iv) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC, including posting of TTC/ATC for interties on the New England Transmission System; provided, however, that such system shall conform to the requirements for such systems as specified by FERC. The PTOs shall provide updates to PTO-specific Local Service pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to direct any changes to such PTO-specific Local Service pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(v) The ISO shall procure and act as supplier of last resort of Ancillary Services (including arranging for the sale and purchase of emergency capacity and energy with neighboring Control Areas), in accordance with the ISO OATT and FERC-accepted or -approved Market Rules.

(vi) The ISO shall provide regional Transmission Service to Transmission Customers over the Transmission Facilities in accordance with the rates, terms and conditions of the ISO OATT, subject to Section 3.03(c) with respect to Local Service.

(vii) The ISO shall track inadvertent energy and administer inadvertent energy payback/accounting with neighboring Control Areas in accordance with the terms and conditions of the Interconnection Agreements or Coordination Agreements with neighboring Control Areas and applicable tariff provisions.

(viii) The ISO shall make informational filings with the Commission that are required of an RTO, provided that the relevant PTOs shall provide the ISO with all necessary information to make such filings, in such manner as the ISO shall reasonably prescribe and in accordance with Section 11.09 of this Agreement.

(b) Notwithstanding Section 3.03(a), generators requesting to interconnect with the distribution facilities of a PTO or a PTO's distribution company Affiliate and retail load customers shall submit service requests to the applicable distribution company or the PTO, where applicable. The distribution company or, where applicable, the PTO shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests.

(c) Local Service. Each PTO authorizes the ISO to act as its agent in the performance of its Transmission Service and OATT administration duties with regard to Local Service, including all ISO responsibilities with respect to Local Service and Local Area Facilities as set forth in Section 3.03(a) above. Each PTO agrees to perform all tasks and undertake all responsibilities necessary and appropriate to facilitate the provision of Local Service in accordance with its Local Service Schedule. Each PTO shall, in accordance with Section 11.09

of this Agreement, provide the ISO with information and data requested by the ISO to perform its Transmission Service and OATT administration duties with regard to Local Service, Each PTO shall maintain its Local Service Schedules in accordance with FERC regulations governing filed rate schedules, shall provide the ISO with copies of proposed changes to its Local Service Schedules when filed with the FERC, and shall notify the ISO when FERC approves or accepts changes to such Local Service Schedules. Each PTO shall be responsible for sending all invoices for Local Service to Transmission Customers and pursuing collections for outstanding payments due for Local Service. The ISO, by the execution of this Agreement, shall not assume any liability in connection with the provision of Local Service other than the liability which may result from an act or omission of the ISO related to the ISO's rights and responsibilities under this Agreement, including an ISO directive and/or instruction to a Party. Nothing in this Section 3.03(c) shall affect the relative rights and responsibilities of the Parties pursuant to Article IX of this Agreement.

(d) Transmission Service Agreements. The ISO and the applicable PTOs shall enter into all agreements for Transmission Service over the Transmission Facilities that commence on or after the Operations Date; provided that:

(i) A pro forma service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, and the PTOs. After the Operations Date, the ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement ("MPSA") or executed service agreements related to the terms and conditions of regional Transmission Service. After the Operations Date, the PTOs, acting jointly in accordance with the Disbursement Agreement among them, shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) related to the terms and conditions of Local Service. and each PTO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend executed service agreements related to the terms and conditions of Local Service.

(ii) On or after the Operations Date, the ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. Such filings with respect to Local Service will be made by the ISO as agent for the applicable PTO. In the event of any dispute between the ISO or a PTO and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma

service agreement set forth in the ISO OATT and shall include in such filing any statement provided by the affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.

(iii) Notwithstanding the foregoing, the PTOs (or their affiliated distribution companies) shall be solely authorized to enter into service agreements for retail service and service to generators connected at the distribution facility level.

Nothing in this Section 3.03(d) shall limit the ISO's obligations with respect to Grandfathered Transmission Agreements in accordance with Section 3.11 of this Agreement. The PTOs shall submit all required electronic reports with respect to such Grandfathered Transmission Agreements. If and to the extent that FERC regulations require the ISO to submit such electronic reports for the Grandfathered Transmission Agreements, the PTOs shall provide the ISO with assistance in developing and submitting such required reports.

(e) Local Networks. A "Local Network" shall consist of those networks of Transmission Facilities identified on Attachment E of the ISO OATT as of the Operations Date. The Local Networks shall only be changed to reflect the effectuation of a merger, acquisition, or consolidation and reorganization, to add a new PTO from outside of the New England Control Area, or to reflect the withdrawal from the ISO of a PTO.

3.04 **Application Authority.**

(a) Each PTO other than a Publicly-Owned PTO shall have the authority to submit filings under Section 205 of the Federal Power Act, and each Publicly-Owned PTO shall have the authority to the extent permitted by, or in a manner consistent with state law applicable to Publicly-Owned PTOs, to establish and to revise:

(i) the revenue requirements for all Transmission Facilities of such PTO used for the provision of Transmission Service (including Transmission Facilities leased to the PTO or to which the PTO has contractual entitlements);

(ii) any rates or charges for transmission services that are based solely on the revenue requirements of the Transmission Facilities of a single PTO (including Transmission Facilities leased to the PTO or to which the PTO has contractual entitlements) under such PTO's FERC-accepted or -approved Local Service Schedule to the ISO OATT;

(iii) any terms and conditions for Local Network Service or Local Point-to-Point Transmission Service under such PTO's Local Service Schedule to the ISO OATT;

(iv) any rates or charges for the recovery of such PTO's investment in a New Transmission Facility or Transmission Upgrade that enters commercial service after the effective date of the ISO OATT and the construction of which was not required by, or approved in, an ISO System Plan; provided, however, that if the ISO OATT utilizes a formula-type transmission rate, the revenue requirement for such Transmission Facility shall not be rolled into such rate without a FERC order expressly permitting such roll-in;

(v) any terms and conditions for such PTO's or such PTO's affiliated distribution company's retail access plans, whether such terms and conditions are included in the ISO OATT or in any other tariff applicable to that PTO filed with FERC, and including any such terms and conditions in the ISO OATT or in any other tariff applicable to that PTO that protect against bypass of any provision of that PTO's retail access plan;

(vi) any rates or charges for the recovery of such PTO's wholesale or retail stranded costs and any terms and conditions in the ISO OATT or in any other tariff applicable to that PTO filed with FERC that protect against bypass of rates or charges for the recovery of that PTO's wholesale or retail stranded costs;

(vii) any rates or charges, and terms and conditions related thereto, that implement an incentive or performance-based rate proposal made by one or more (but fewer than all) PTOs, applicable only to service provided by such PTO(s) under their Local Service Schedules; and

(viii) subject to the provisions of Section 2.05, any terms and conditions of Interconnection Agreements with any entities connecting with such PTO's Transmission Facilities, provided that such Interconnection Agreements shall not include any operating arrangements and Coordination Agreements that the ISO may enter into with operators of neighboring Control Areas in accordance with Section 3.02(b).

A PTO shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(c). The PTO shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (ii) through (viii), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. The PTO shall consult with interested stakeholders upon request. The PTO shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (ii) through (viii), above, the PTO shall include in any filing a statement that, in the good faith judgment of the PTO, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (ii)

through (viii), above, would have such an inconsistency, it shall so advise the PTO and such PTO and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, the PTO may submit a filing under Section 205, provided that the PTO's filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns. With respect to any PTO whose transmission rates and revenue requirements are not subject to FERC jurisdiction under Section 205 or otherwise, such PTO shall have the right to establish its revenue requirements, and, where applicable, its rates and charges, in accordance with applicable law and submit such revenue requirements, rates and charges to FERC for a determination that inclusion of such revenue requirements, rates and charges in the ISO OATT will yield rates and charges for Transmission Service that satisfy the applicable standard under Section 205.

A PTO shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. The PTO's filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The PTOs, acting jointly in accordance with the Disbursement Agreement among them, shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise:

(i) the rates and charges for Transmission Service pursuant to which the revenue requirements for all Transmission Facilities of the PTOs used for the provision of Transmission Service are recovered; including the design of any rates or charges for: (A) regional Transmission Service on the New England Transmission System involving the use of more than one PTO's Transmission Facilities; (B) Transmission Service between the New England Transmission System and any other transmission system; (C) Transmission Service through the New England Transmission System between other transmission systems; (D) the recovery of any portion of the revenue requirements of the PTOs attributable to the elimination of any rates or charges (e.g., border charges) for any such Transmission Service; (E) the methodology by which the costs of Transmission Upgrades related to generator interconnections are allocated under the ISO OATT and (F) the methodology by which the costs of New Transmission Facilities and Transmission Upgrades are allocated under the ISO OATT.

(ii) the methodology for the recovery and allocation of the line losses on the New England Transmission System, if and to the extent that the calculation of locational marginal prices for energy is not designed to recover such losses; and

(iii) any rates or charges, and terms and conditions related thereto, that implement an incentive or performance-based rate proposal, applicable to the entire New England Transmission System.

The PTOs shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(c). The PTOs shall provide written notification of any proposed filing under this Section 3.04(b) to the ISO and stakeholders, which notification shall include a detailed description of the proposed filing, at least 30 days prior to the filing. The PTOs shall retain the right to modify aspects of any filing authorized by this Section 3.04(b) after they provide written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings. If less than all of the PTOs support the filing, the PTOs will advise the ISO and stakeholders of that fact and the dissenting PTOs shall advise the ISO and stakeholders of their concerns.

The PTOs and the ISO shall make every reasonable effort to agree upon the PTOs' proposed filing under this Section. In the event the PTOs and the ISO are unable to agree on the PTOs' filing under this Section, and the ISO in its good faith judgment concludes that the PTOs' filing will:

(A) be inconsistent with the design of the New England Markets, including the congestion pricing methodology for the ISO region, as accepted or approved by FERC;

(B) have a material adverse effect on the efficiency or competitiveness of the New England Markets, or on the ability of the ISO to provide transmission access on a not unduly discriminatory or preferential basis; or

(C) have a material adverse effect on the reliability of the ISO bulk power system;

then, except as provided in the next sentence, the PTOs' filing will not become effective until such time as FERC issues an order determining the proposal set forth in the filing to be consistent with the standard applicable under Section 205 of the Federal Power Act, and such a filing (including the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns. In the case of a filing described in sub-paragraph (iii), above, the PTOs may request that FERC permit the filing to go into effect on an interim basis, notwithstanding the conclusion of the ISO. If FERC grants the PTOs' request to permit the filing to go into effect on an interim basis, the filing will become effective, subject to refund, on the date specified in FERC's order.

The PTOs shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(b) and when any needed software modifications could reasonably be expected to be implemented. The PTOs' filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(b), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(b) once such software modifications have been implemented.

(c) The ISO shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise:

> (i) any terms and conditions of the ISO Tariff, and any separate ISO tariffs, relating to Transmission Service and/or the New England Markets , provided that: (A) the ISO shall not have the authority to revise such terms and conditions in a manner that would abridge the rights granted to the PTOs in Section 3.04(a) or Section 3.04(b); (B) the ISO shall not have the authority to eliminate Local Network Service or Local Point-to-Point Transmission Service provided under the Local Service Schedules; (C) the ISO shall not file to change the state or federally-accepted or -approved terms and conditions of any PTO's retail access plan or the terms and conditions of any retail access plans of a PTO's affiliated distribution company's (including any such terms and conditions that protect against bypass of any provision of a PTO's retail access plan) or the state or federally-accepted or -approved rates and other mechanisms for the recovery of a PTO's wholesale or retail stranded costs in effect as of the Operations Date; and (D) the ISO shall not have the authority to transfer to any third party the ISO's Section 205 rights to revise the terms and conditions of Transmission Service or the authority to enter into agreements with any group of stakeholders to submit filings under Section 205 of the Federal Power Act to change the terms and conditions of Transmission Service where such proposed changes are not supported by the ISO but are approved by a vote of the stakeholder group.

The ISO shall provide written notification of any proposed filing under this Section 3.04(c) to the PTOs and stakeholders, which notification shall include a detailed description of the proposed filing, at least 30 days prior to the filing. The ISO shall consult with the PTOs and stakeholders and will consider any comments any PTO or stakeholder provides in developing its filing. The ISO shall retain the right to modify aspects of any filing authorized by this Section 3.04(c) after it provides written notification to the PTOs and stakeholders and shall provide notification to the PTOs and stakeholders of any material modification to such filings. In addition, the ISO shall

consult with the PTOs to determine whether the filing will have any adverse impact on any PTO's revenue requirements, or on the ability of any PTO to recover its revenue requirements, or have a material adverse impact on the ability of any PTO to implement an incentive rate plan then in effect. If the affected PTOs conclude in their good faith judgment that the filing will have any of such effects, the ISO and the affected PTOs will make every reasonable effort to resolve the concerns of the affected PTOs. In the event that the affected PTOs' concerns cannot be resolved, the ISO may, nevertheless, make a filing under Section 205 provided that, except as provided in the next sentence, such a filing will not become effective until such time as the Commission issues an order determining the proposal set forth in the filing to be consistent with the standard applicable under Section 205 of the Federal Power Act. The ISO may request that FERC permit a filing authorized by this Section 3.04(c) to go into effect on an interim basis, notwithstanding the conclusion of the affected PTOs, provided that the ISO shall include in such a filing (and the transmittal letter for such a filing) any written statement provided by the affected PTOs setting forth the basis for the affected PTOs' concerns. If FERC grants the ISO's request to permit the filing to go into effect on an interim basis, the filing will become effective, subject to refund, on the date specified in FERC's order. Notwithstanding the foregoing, in Exigent Circumstances , the ISO shall have the unilateral authority, upon written notice to the PTOs, the Participants Committee, and the individual Participants, to submit any filing under Section 205 of the Federal Power Act to modify any provision of the ISO Tariff as authorized in this Section 3.04(c), provided that such filing shall be subject to all conditions set forth in this Section 3.04(c) except for those conditions that would limit the ISO from submitting or implementing such an ISO unilateral filing on an expedited basis or that would require the consultation otherwise specified herein.

(d) Except as explicitly set forth in Section 3.04(e), with respect to certain items listed in Sections 3.04(a) and 3.04(b), the ISO shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(a) or Section 3.04(b). The PTOs shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(c). The ISO reserves its rights to intervene in, comment on or protest any filing made by the PTOs, and to submit proposals for the consideration of the PTOs and the PTOs reserve their rights to intervene in, comment on or protest any filing made by the ISO, and to submit proposals for the consideration of the ISO.

(e) In the event the ISO determines that a change in the design of any provision of the ISO OATT described in Section 3.04(a)(ii), (iii), (iv) or (vii) or 3.04(b) is required because the existing design of any rates or charges for Transmission Service is inconsistent with the design of the New England Markets, and such inconsistency will, if not remedied before relief would be available in a proceeding under Section 206 of the Federal Power Act, either: (i) substantially and adversely affect the efficiency or competitiveness of the New England Markets, or (ii) substantially and adversely affect the reliability of the ISO bulk power system, a senior officer of the ISO shall notify the affected PTO(s) of its determination. Upon receipt of such notification, the affected PTO(s) and the ISO shall diligently work together

to arrive at appropriate changes in the rates to alleviate the conditions that led to this notification being given, while protecting the rights of the affected PTO(s) to fully recover their revenue requirements and the amount of incentive payments associated with FERC-accepted or -approved incentive arrangements for the PTO(s). If the affected PTO(s) and the ISO agree on a solution to this issue, the affected PTO(s) shall make a filing at FERC under Section 205 consistent with such agreement.

If the affected PTO(s) and the ISO cannot agree on a mutually acceptable Section 205 filing to address this issue within a period of thirty (30) days, and the affected PTO(s) do not make a Section 205 filing within the thirty (30) day period, then the ISO shall have the authority to submit a filing under Section 205 of the Federal Power Act as permitted herein. provided that such a Section 205 filing shall not be submitted until the PTOs have an opportunity to meet with representatives of the ISO Board of Directors if requested by any PTO with reasonable notice, and the ISO may, with the approval of FERC, place a replacement for such rate design into effect, while the proceeding on the ISO's filing is pending before FERC, for a period no longer than fifteen (15) months, provided that such filing shall not propose a modification that adversely affects the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements and the amount of incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or that would result in any costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate thereafter becoming unrecoverable under either a federal or state-jurisdictional rate, and the replacement rate design proposal of the ISO is subject to refund and surcharge, as necessary to restore the status quo ante if FERC does not ultimately approve that proposal. To place its replacement rate design proposal into effect, the ISO shall bear the burden of persuading FERC that: (i) the ISO's replacement proposal is consistent with the standard applicable under Section 205 of the Federal Power Act; (ii) the ISO's determination regarding the inconsistency of the existing rate design with the design of the New England Markets and the impact of that inconsistency, as set forth in the first sentence of this subsection, is correct; and (iii) the ISO's proposal will not adversely affect the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements or the amount of incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or to fully recover costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate. Notwithstanding the foregoing, in Exigent Circumstances , the ISO shall have the unilateral authority, upon written notice to the PTOs, the Participants Committee and the individual Participants, to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO Tariff described in this Section 3.04(e), provided that such filing shall be subject to all conditions set forth in this Section 3.04(e) except for those conditions that would limit the ISO from submitting or implementing such an ISO unilateral filing on an expedited basis or that would require the consultation otherwise specified herein.

(f) In the event the ISO concludes that a filing to establish or to revise the terms and conditions listed in Section 3.04(c) is required and that providing the notification or consultation required under Section 3.04(c) for such filing would result in an unanticipated material adverse effect on the efficiency or competitiveness of the New England Markets or the reliability of the ISO bulk power system in the circumstances, the ISO: (i) shall provide such

notification to the PTOs and stakeholders or undertake such consultation with the PTOs and stakeholders as is possible under the circumstances; and (ii) may submit a filing under Section 205 to establish or to revise the terms and conditions listed in Section 3.04(c) upon issuance of a written statement setting forth the circumstances that do not permit such notification or consultation.

(g) In the event the PTO(s) conclude that a filing to establish or to revise the rates, terms and conditions listed in Section 3.04(a) or 3.04(b) is required and that providing the notification or consultation required under Section 3.04(a) or Section 3.04(b) for such filing would result in an unanticipated material under-recovery of the PTO(s)' revenue requirements or other material adverse financial effect on the PTO(s), the PTO(s): (i) shall provide such notification to the ISO and stakeholders or undertake such consultation with the ISO as is possible under the circumstances; and (ii) may make a Section 205 filing to establish or to revise the rates, terms and conditions listed in Section 3.04(a) or 3.04(b) upon issuance of a written statement setting forth the circumstances that do not permit such notification or consultation.

(h) Cost Allocation Moratorium

(i) During the five (5) year period commencing on the Operations Date (the "Moratorium Period"), neither the PTOs, pursuant to Section 3.04(b), nor the ISO, pursuant to Section 3.04(e), shall submit filings under Section 205 of the Federal Power Act to modify:

(A) the provisions and schedules of the ISO OATT governing the split between PTF and Non-PTF transmission facilities in effect prior to the Operations Date for purposes of allocating costs to Transmission Customers;

(B) the provisions and schedules of the ISO OATT establishing the methodology by which the costs of Transmission Upgrades and New Transmission Facilities related to generator interconnections are allocated under the ISO OATT; and

(C) the provisions and schedules of the ISO OATT establishing the methodology by which the costs of New Transmission Facilities and Transmission Upgrades are allocated under the ISO OATT;

(ii) The Parties' agreement to forego submission of Section 205 filings during the Moratorium Period with respect to the items listed in Section 3.04(h)(i) (A) through (C) above shall not restrict in any way the rights of the PTOs, pursuant to and in accordance with Sections 3.04(b) or 3.04(a), to submit Section 205 filings to modify any elements of the rates applicable to Transmission Service other than those items listed in Section 3.04(h)(i) (A) through (C). Nothing in this Section 3.04(h) shall restrict in any way the rights of the PTOs to submit Section 205 filings to establish incentive or performance-based rates in accordance with

Section 3.04(b)(iii) or to submit Section 205 filings to establish formula or stated rates in accordance with Section 3.04(b)(i), provided that such filings do not propose to modify the items listed in Section 3.04(h)(i) (A) through (C). Nothing in this Section 3.04(h) shall restrict in any way the rights of the ISO, pursuant to and in accordance with Section 3.04(e), to submit Section 205 filings to modify any elements of the rates applicable to Transmission Service other than, provided that such filings do not propose to modify the items listed in Section 3.04(h)(i) (A) through (C).

(iii) Notwithstanding Section 3.04(h)(i)(B) above, to the extent that the requirements for any New Transmission Facilities or Transmission Upgrades associated with new or existing generation set forth in the ISO OATT are modified during the Moratorium Period in a manner that creates a new or modified category of generator-related transmission costs, the PTOs shall have the authority, in accordance with Section 3.04(b), to submit Section 205 filings during the Moratorium Period to establish the methodology by which such new or modified generator-related transmission costs are allocated.

(iv) Nothing in this Section 3.04(h) shall supersede or alter the effect of any FERC orders concerning the allocation of costs for specific transmission facilities in the New England region.

(v) Nothing in this Section 3.04(h) shall restrict in any way the rights of the ISO or of any PTO during the Moratorium Period to submit a filing under Section 206 of the Federal Power Act to modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C).

(vi) After the end of the Moratorium Period, the PTOs may exercise their rights in accordance with Section 3.04(b)to submit Section 205 filings to modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C); provided that:

(A) The PTOs must provide the ISO, the Regional State Committee established by the states in the ISO region (the "Regional State Committee"), and stakeholders no less than 90 days advance notification of the proposed filing, including a detailed description of any proposed change to the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto). The PTOs, the ISO and the Regional State Committee shall engage in a process of consultation and negotiation in order to attempt to reach consensus on such filing.

(B) At least 30 days prior to the proposed filing date the Regional State Committee may inform the PTOs that the Committee opposes the PTOs' proposal to change the cost allocation provisions set

forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto).

(C) If the Regional State Committee opposes the PTOs' proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto), the PTOs may make the Section 205 filing to modify the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto); provided that: (1) such filing may not go into effect until FERC has approved the filing; (2) the Regional State Committee will have the right to provide the PTOs with an alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) which the PTOs will include in their Section 205 filing and which will be considered on an equal footing with the PTOs' proposal in the FERC proceeding, and (3) such alternative proposal shall not adversely affect the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements and the amount of incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or result in any costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate thereafter becoming unrecoverable under either a federal or state-jurisdictional rate.

(D) If, notwithstanding the requirements of Section 3.04(h)(vi)(C), the Regional State Committee submits an alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) that any PTO believes causes an under-recovery of costs when used in conjunction with the other elements of the rate design for transmission rates filed by the PTOs (or the one already in effect if the PTOs' filing does not propose to change the rate design), the PTO(s) will have the right: (1) to include in such filing an explanation of why the PTO or PTOs believe the Regional State Committee proposal causes an under-recovery of costs contrary to the requirements of Section 3.04(h)(vi)(C); and (2) to file a modified rate design that eliminates such under-recovery (or a rate mechanism filed by one or more PTOs individually for that purpose, when the under-recovery affects them uniquely) in the event that the alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) is approved by the FERC placed into effect coincident with the effective date of such proposal.

(E) Any requirements established by this Section 3.04(h)(vi) with respect to the Regional State Committee shall not subject any PTO or

ISO-NE to the jurisdiction or authority of any agent or agency of any state participating in the Regional State Committee.

(vii) After the end of the Moratorium Period, the ISO may exercise its rights in accordance with Section 3.04(e) to submit Section 205 filings to modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C) if the PTOs fail to alleviate the conditions specified in Section 3.04(e).

(i) The ISO shall have sole authority to submit Section 205 filings to recover its administrative, capital and other costs (including the collection of funds from Transmission Customers to support payment of FERC annual charges with respect to transmission service for which the ISO is the Transmission Provider as defined in FERC rules and orders) including the design of any charges therefore (the "ISO Administrative Charge").

(j) Nothing in this Agreement shall restrict in any way the rights of the ISO or of any PTO to submit an application under Section 206 of the Federal Power Act for revisions to the rates, terms and conditions of service under the ISO OATT. Nothing in this Agreement shall subject any Publicly-Owned PTO to regulation of rates and charges applicable to its transmission facilities under Sections 205 or 206 of the Federal Power Act; provided, however, that the justness and reasonableness of regional transmission rates or charges may be evaluated in light of the levels of, and manner in which, the costs of Publicly-Owned PTOs' transmission facilities are recovered under regional transmission rates.

(k) Nothing in this Agreement shall restrict in any way the rights of any PTO to submit a proposal under Section 205 of the Federal Power Act to participate in, join, or become an ITC pursuant to Attachment M to the ISO OATT and, upon approval of such proposal, to withdraw from this Agreement in accordance with Section 10.01 of this Agreement.

(l) Stakeholder Process for Regional Rate Filings.

(i) Absent unanticipated circumstances, every PTO proposal to modify regional rates in accordance with Section 3.04(b) shall be presented by the PTOs to the appropriate stakeholder Technical Committee(s) for consideration and an advisory vote. The Technical Committee, at its next meeting following the one at which the intial presentation is made (which shall be no later than 30 days after any proposal is made), shall: (i) vote on the merits of the proposal as presented or with changes accepted by the PTOs; or (ii) by motion and vote of 66-2/3%, defer action on any proposal presented if it reasonably determines that additional information should and could be provided to more adequately inform the members of such Technical Committee before a vote on the merits is taken. Any deferral shall be for no more than 30 days, after which the PTOs may move for an advisory vote upon their proposal at the next meeting of the Technical Committee (which shall be held within 30 days of the start of the deferral). At that time, the Technical Committee may vote on the merits of the proposal as presented or with changes approved by the Committee, or may vote to oppose the proposal on the

grounds that sufficient information has still not been provided, but may not defer consideration of the proposal for any further period without the consent of the PTOs. Failure of the Technical Committee to vote within the time frames set forth in this paragraph shall advance the process to the next step, and in no event shall a period of longer than 60 days be required for the PTOs to submit a proposal to modify regional rate design in accordance with Section 3.04(b) to the Participants Committee.

(ii) Absent unanticipated circumstances and after the fulfillment of the procedures outlined in Section 3.04(l)(i), every PTO proposal to modify regional rates in accordance with Section 3.04(b) shall be presented by the PTOs to the stakeholder Participants Committee for an advisory vote, along with a report of any action, failure to act or advisory vote taken by any Technical Committee(s). Such report shall be considered by the Participants Committee no later than the first regularly scheduled meeting following notification of that presentation. The Participants Committee shall: (i) vote on the merits of the proposal as presented or with changes accepted by the PTOs; or (ii) by motion and vote defer action on any proposal if it reasonably determines that the proposal presented is materially different from the proposal presented to the Technical Committee, and was not voted on by the Technical Committee. Any deferral shall result in a repeat of the processes outlined above. Notwithstanding the foregoing, the Participants Committee may, at its discretion, consider and vote upon any proposal submitted to it and such a vote shall have the same effect as if the proposal had first been voted upon by a Technical Committee. The Participants Committee may not defer action on any item that has been voted on by a Technical Committee and presented to the Participants Committee for an advisory vote unless the PTOs consent to such deferral. If the Participant Committee has not scheduled a meeting to vote on the merits of a PTO proposal to modify regional rates in accordance with Section 3.04(b) prior to date that the PTOs intend to submit such a proposal to the FERC, then the PTOs shall request that the Participants Committee schedule a special meeting to conduct an advisory vote on the merits of such proposal. In no event shall the PTOs be required to wait for a Participant Committee advisory vote for a period of longer than 90 days after initial notification of such proposal to stakeholders prior to submitting a proposal to modify regional rate design in accordance with Section 3.04(b) to the FERC.

(iii) An advisory vote by the Participants Committee on the merits of any proposal, whether in favor of or in opposition, terminates the stakeholder proceedings absent voluntary resubmission of the same or a modified proposal by the PTOs, at a future time. The PTOs shall report the results of such advisory vote in any relevant filing made by the PTOs with the FERC. A failure by the Participants Committee to vote within the time frames outlined above terminates the Participant proceedings absent voluntary resubmission of the same or a modified proposal by the PTOs at a future time.

(iv) Nothing in this Section 3.04(l) shall limit the ability of the PTOs to submit a filing pursuant to Section 3.04(g) to modify regional rates in the event the PTOs conclude that a filing to modify regional rates is required due to unanticipated circumstances, provided that the PTOs shall provide such notification to the stakeholder Participant Committee or undertake such consultation with the stakeholder Technical Committee(s) and Participant Committee as is possible under the circumstances and shall provide the Participants Committee with a written statement setting forth the circumstances that do not permit the notification or consultation otherwise required by this Section 3.04(l).

(v) The process set forth in this Section 3.04(l) shall not apply to filings related to regional rates submitted to the FERC on an informational basis. The applicable process for review of such informational filings shall be set forth in the ISO OATT.

(m) Highgate Transmission Facilities (HTF).

(i) The costs of the HTF shall be included in the transmission rates for Regional Network Service on a phased-in basis, in accordance with Appendix B to the Attachment F Implementation Rule of the ISO OATT, provided that:

(A) the costs of the HTF shall be fully phased into the transmission rates for Regional Network Service in year 5 as defined in Appendix B to the Attachment F Implementation Rule of the ISO OATT;

(B) the HTF shall not be classified as PTF for rate purposes under the ISO OATT; and

(C) the rate treatment of the HTF shall establish no precedent or presumption concerning rate treatment of any other HVDC transmission facilities.

(ii) the HTF shall be classified as Category A Facilities, provided, however, that the classification of the HTF as Category A facilities under this Agreement shall establish no binding precedent or presumption concerning the operational and other terms and conditions for other HVDC facilities over which the ISO may obtain operational and other authority under this TOA or other ISO operating agreements in the future.

3.05 **The ISO's Responsibilities.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability;

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities; and

(iii) act without undue preference to any Party.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **Each PTO's Responsibilities.**

(a) From and after the Operations Date, each PTO shall, in accordance with Good Utility Practice:

(i) direct, physically operate, repair, and maintain its Transmission Facilities and Local Control Centers in accordance with this Agreement, applicable Law, and applicable Operating Procedures;

(ii) operate and maintain, or arrange for a third party, approved by such PTO, in its sole discretion, to operate and maintain, one or more suitable Local Control Centers (including any Local Control Centers maintained as back-up for a PTO's primary Local Control Centers). Each PTO shall provide the ISO with reasonable notice of any change to its Local Control Center(s) and shall coordinate with the ISO to ensure that such a change will not adversely affect the reliable operation of the New England Transmission System. Each PTO shall have the responsibility to ensure that its Local Control Center(s) will: operate PTO Transmission Facilities on a 24 hour basis, implement the instructions, orders and directions received from the ISO in the exercise of its Operating Authority in accordance with Section 3.02, and perform the following functions in accordance with applicable Operating Procedures:

(A) switching and tagging;

(B) on-line monitoring;

(C) security analysis;

(D) dispatch voltage and reactive power, provided that the ISO shall dispatch voltage and reactive power to the extent the

Local Control Centers are unable to maintain normal voltage schedules;

(E) coordinate the development of settings for dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other similar dynamic equipment that affects power flows;

(F) implementation of the PTO Local Restoration Plan and development of modifications to such PTO Local Restoration Plans, subject to the approval of the ISO in order to coordinate and promote the reliability of the Restoration Plans;

(G) operation and maintenance of communication systems and software;

(H) implementation of voltage reduction measures;

(I) implementation of Load Shedding;

(J) coordinate with the ISO and the other PTOs with respect to congestion management efforts and, to the extent applicable, demand-side management and distributed generation efforts, provided that a PTO employee who is engaged in such coordination and who is not a Local Control Center employee shall be subject to the same standards of conduct and applicable provisions of the ISO Information Policy as a Local Control Center employee; and

(K) coordinate with other entities interconnected with the New England Transmission System.

(iii) cooperate with the ISO's performance of the monitoring and audits in connection with all monitoring and compliance provisions detailed in Section 3.02(i) of this Agreement;

(iv) consistent with practice prior to the Operations Date, designate its Local Control Centers to serve as back up to the ISO reliability functions until the ISO re-establishes operational control at its own Back-up Control Center; provided that, in such situations, necessary information will be made available to such Local Control Centers to facilitate the continued operation of the New England Transmission System and that each PTO will comply with Section 11.09

and the ISO Information Policy on file with FERC to prevent such information from reaching any unauthorized person or entity;

(v) collaborate with the ISO with respect to:

(A) the development of Rating Procedures,

(B) the establishment of ratings for each PTO's New Transmission Facilities;

(C) the establishment of ratings for each PTO's Acquired Transmission Facilities that do not have an existing rating as of the Operations Date, and

(D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and any PTO or PTOs concerning Rating Procedures or the rating of a Transmission Facility owned by such PTO or PTOs, such disagreement shall be the subject of good faith negotiations between the applicable PTO or PTOs and the ISO, provided that; (x) the applicable PTOs' position concerning such Rating Procedures or Transmission Facility ratings shall govern until the applicable PTOs and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(v) shall limit the rights of the ISO or of any PTO to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, the PTOs shall continue to provide the ISO with up-to-date ratings information in accordance with the applicable Rating Procedures.

(vi) undertake operating actions in accordance with any tariffs or rate schedules approved or accepted by FERC;

(vii) provide the ISO with the right to use a level of communications capacity (and maintain the equipment associated with this capacity in accordance with Good Utility Practice) on its telecommunication assets and equipment attached to or associated with Transmission Facilities consistent with practice prior to the Operations Date in order to supply reliability-related data including meter, voice and data communications; continue to receive and send (for Regulation purposes) telemetry to and from existing generators and transmission substations; provide for the receipt of such information from generators and substations, and provide metering data and/or telemetry to the ISO (including providing the infrastructure for Regulation and Frequency Response Service), as reasonably necessary for the ISO to perform its obligations under this Agreement

and the ISO OATT; provided that a PTO shall have the unfettered right to use communications capacity on its telecommunication assets and equipment attached to or associated with Transmission Facilities for other business purposes to the extent such capacity is not being used by the ISO as of the Operations Date; and provided further that: (1) as required by the pro forma Large Generator Interconnection Agreement in the ISO OATT, each PTO shall include provisions in its Interconnection Agreements with generators after the Operations Date providing for the installation and maintenance of sufficient communications capability to allow the ISO to exercise its Operating Authority with respect to such generators, and (2) the ISO may include the installation of additional communications capacity as an identified need in the regional transmission expansion plan, in which case such installation may be included within the PTO obligation to build set forth in, and subject to the terms and conditions in, Section 7 of Schedule 3.09(a).

(viii) notify the ISO prior to making changes to the operational status of such PTO's Category B Facilities and provide information on the operational status of Category B Facilities consistent with practice prior to the Operations Date;

(ix) operate or cause to be operated its Local Area Facilities in a manner that does not result in the violation of reliability standards applicable to the New England Transmission System;

(x) provide the ISO with revenue metering data or cause the ISO to be provided with such revenue metering data;

(xi) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) Operation of Transmission Facilities During A System Failure. Existing Operating Procedures for use during a System Failure shall be utilized by the ISO and the PTOs. Any modifications to the Existing Operating Procedures for use during a System Failure or new Operating Procedures for use during a System Failure shall be developed by the ISO in the manner specified in Section 3.02(d). The procedures for use during a System Failure shall provide that, in situations where immediate action is required, each PTO's Local Control Center(s) shall have the authority to take the following reliability actions at a minimum, provided that each PTO shall coordinate with the ISO as soon as practicable upon taking such action:

(i) Undertake those operational functions with respect to Transmission Facilities undertaken by the ISO under non-System Failure conditions;

(ii) Re-energize transmission facilities following breaker trips;

(iii) Implement emergency Load Shedding and voltage reduction measures and subsequent restoration;

(iv) Implement Voltage/VAR control;

(v) Adjust PARS settings;

(vi) Dispatch generation as necessary to preserve system reliability; in accordance with applicable NERC/NPCC Requirements and ISO directives; and

(vii) Take such other measures necessary, consistent with Good Utility Practice, to respond to a System Failure.

Nothing in this Section 3.06(b) shall limit the right of each PTO pursuant to Section 3.07 to take any action(s) that it deems necessary to prevent loss of human life, injury to persons and/or damage to property.

3.07 **Reserved Rights of the PTOs**.

(a) Notwithstanding any other provision of this Agreement to the contrary, each PTO shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory standards. This Section 3.07 is not intended to reduce or limit any other rights of a PTO as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of each PTO that is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to such PTO's reallocation or redistribution of revenues or the assignment of such PTO's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of any PTO to terminate its participation in this Agreement pursuant to Article X of this Agreement, notwithstanding any effect its termination from the ISO may have on the distribution of transmission revenues among other PTOs.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, each PTO retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to the PTO's compliance with Section 2.06 of this Agreement. Subject to Article X, a PTO may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of such PTO's Transmission Facilities subject to this

Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) Any expansion or modification by a PTO of its Transmission Facilities, any facilities constructed by a PTO to connect the facilities of a current or proposed Transmission Customer to such Transmission Facilities, and/or any new transmission facilities constructed by a PTO pursuant to the ISO Planning Process shall be subject to such PTO's right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all costs prudently incurred or prudently committed to be incurred, plus a return on invested equity and other capital, associated with constructing and owning or financing such facilities, expansions or modifications to its Transmission Facilities, in accordance with Schedule 3.09(a) hereof.

(iv) The responsibilities granted to the ISO under this Agreement shall not affect the rights of a PTO to modify or expand its Transmission Facilities, nor confer upon the ISO any authority to direct a PTO to modify or expand its Transmission Facilities except as provided in Schedule 3.09(a), and each PTO shall retain all rights and responsibilities specifically assigned to PTOs pursuant to Schedule 3.09(a).

(v) Each PTO shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(vi) Each PTO retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(vii) Nothing in this Agreement shall be construed as limiting in any way the rights of a PTO to make any filing with any applicable state or local regulatory authority.

(viii) Each PTO may request that the ISO commit additional generators (including specific output levels), or each PTO may take other actions permitted under the ISO OATT and Market Rules (including self-scheduling), if the PTO determines that additional generation is needed to ensure local area reliability, provided that the ISO shall make the final determination whether to commit additional generation in accordance with applicable provisions of the ISO OATT and Market Rules

(ix) Subject to Section 2.05, each PTO shall retain the right to enter into Interconnection Agreements with transmission owners, generators and other entities connecting with such PTO's transmission facilities (including

Transmission Facilities) and to file such agreements for approval or acceptance by FERC.

(x) Each PTO shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.07 shall not relieve the PTO of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of a PTO related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with such PTO.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the PTOs under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of any PTO to take any position, including opposing positions, in any administrative or judicial proceeding or filing by other PTOs or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

(d) Nothing in this Agreement shall be deemed to impair or infringe on the exemption of Publicly-Owned PTOs, under Section 201(f) of the Federal Power Act, from the obligations and requirements of the Federal Power Act. Notwithstanding anything to the contrary in this Agreement, nothing contained herein shall subject any Publicly-Owned PTO to any requirement or obligation imposed by the Federal Power Act that would not apply to such Publicly-Owned PTO in the absence of this Agreement.

3.08 **Repair and Maintenance of Transmission Facilities.**

(a) Planning, Scheduling, and Approval of Transmission Facility Outages.

(i) Each PTO shall submit to the ISO long-term plans for Transmission Facility outages, shall submit to the ISO schedules for Transmission Facility outages, and shall obtain ISO approval for Transmission Facility outages in accordance with, and to the extent required by, Market Rule 1.

(ii) Notwithstanding any of the foregoing, nothing in this Section 3.08 shall be construed to require a PTO to reschedule an outage of a Transmission Facility or to require a PTO to refrain from initiating switching and tagging procedures to take a Transmission Facility out of service or place it back into service to the extent a PTO determines that such outage or actions are necessary to prevent injury or damage to persons or property or to protect its facilities from physical damage, in accordance with Section 3.07(a)(v) of this Agreement.

(b) Recovery of Transmission Outage Rescheduling Costs. The PTO(s) shall have the right, either collectively pursuant to and in accordance with Section 3.04(b), or individually pursuant to and in accordance with Section 3.04(a), to file a schedule to the ISO OATT that will provide for reimbursement to the affected PTO(s) for any direct costs incurred by the PTO(s) due to the ISO's rescheduling or revocation of a previously scheduled or approved Transmission Facility outage to the extent the ISO reschedules or revokes a previously scheduled or approved Transmission Facility outage in accordance with Market Rule 1.

(c) Annual Assessment of Outage Coordination Efforts. The ISO shall prepare and issue annual public reports on the scheduling and coordination of transmission outages. Each such annual report shall: (i) assess the accuracy of the ISO's estimation of congestion and RMR cost impacts and the accuracy of PTO and other inputs used in such estimation; (ii) assess any long term impacts of the ISO's exercise of its authority to require the rescheduling of transmission maintenance outages and. (iii) include analyses and data which could allow a PTO to identify potential opportunities for incentives based on efficient coordination of outages and other operational measures that will reduce congestion costs or increase operational flexibility. The ISO shall provide a draft of each such annual report to the PTOs and interested stakeholders prior to issuing a final report and shall consider the input of the PTOs and interested stakeholders in preparing such reports, subject to any applicable restrictions set forth in the ISO Information Policy on file with FERC.

(d) Development of Incentive Proposals. Notwithstanding any other provision in this Agreement, the ISO will apply reasonable efforts to work actively with any interested PTO(s) to analyze alternatives including incentives adopted in other markets and to provide input for use by the interested PTO(s) in developing the design of incentive rates or mechanisms for regional congestion cost reduction. The ISO will work with other stakeholders in a similar fashion if so requested. Any such incentive proposal shall be filed by a PTO or PTOs with FERC in accordance with Section 3.04(a) or Section 3.04(b) as applicable. Such incentive mechanisms shall be designed to further improve coordination of outages or operational measures in a manner that will reduce overall congestion or RMR costs. Any PTO incentive must be approved or accepted by FERC. Each PTO developing an incentive proposal shall attempt to reach agreement with the ISO before filing an incentive proposal with FERC. The ISO may submit filings to the FERC (including a protest or a complaint under Section 206 of the Federal Power Act) raising any questions or concerns that it may have concerning a specific incentive proposal, provided that the ISO shall not contend that an incentive proposal is inappropriate or oppose the proposal on the ground that the PTOs have agreed to the provisions of Section 3.08 of this Agreement.

(e) Market Monitoring of Outage Scheduling. The Market Monitoring Unit of the ISO shall monitor the outage scheduling activities of the PTOs. The Market Monitoring Unit of the ISO shall have the right to request that each PTO provide information to the Market Monitoring Unit concerning the PTO's scheduling of Transmission Facility outages, including the rescheduling or cancellation of any Planned, Scheduled or Approved Outage, and the PTO shall provide such information to the Market Monitoring Unit in accordance with Section 11.09(c) of this Agreement.

(f) Damage or Destruction of Transmission Facilities.

(i) If, at any time during the Term, any of a PTO's Transmission Facilities are damaged or destroyed, then, such PTO shall determine, in its sole discretion, consistent with Good Utility Practice and applicable Law, whether or not (and if so, in what manner) to restore or cause the restoration of such damaged or destroyed Transmission Facilities to substantially the same condition, character or use as existed before the damage or destruction, if at all, provided that such PTO shall consult with the ISO prior to making such determination and shall comply with the requirements specified in Section 2.06.

(ii) Nothing in this Section 3.08(f) shall limit the authority of the ISO to direct a PTO to modify or expand its Transmission Facilities in accordance with the ISO Planning Process, subject to the terms and conditions of Schedule 3.09(a) hereof.

3.09 **Planning and Expansion.**

(a) Each PTO shall perform all of its responsibilities, and exercise each of its rights, with respect to the planning and expansion of the New England Transmission System in accordance with the ISO OATT and Schedule 3.09(a) hereto. The ISO shall perform all of its responsibilities pursuant to the ISO Planning Process set forth in the ISO OATT. Each PTO shall engage in planning for its Local Area Facilities in a manner that is consistent with applicable NERC/NPCC Requirements, Good Utility Practice and the ISO OATT. The ISO and each PTO shall perform all such responsibilities in accordance with applicable Laws and Good Utility Practice. Nothing in this Agreement shall be construed to impose on any PTO an obligation to build transmission facilities except as provided in Schedule 3.09(a) hereto.

(b) The ISO shall utilize the Planning Procedures relating to the planning and expansion of the New England Transmission System. The Planning Procedures shall initially consist of the Planning Procedures in existence on the Operations Date (hereinafter "Existing Planning Procedures"). Such Existing Planning Procedures shall consist of those Planning Procedures listed in Schedule 3.09(b). The ISO shall develop any modifications to Planning Procedures (including Existing Planning Procedures) and any new Planning Procedures that it may deem necessary or appropriate in coordination with the PTOs and other stakeholders. In the event that the ISO and the applicable PTO(s) disagree about modifications to the portions of

the Planning Procedures related to the planning and expansion of Transmission Facilities or any new Planning Procedures related to the planning and expansion of Transmission Facilities, the affected PTO(s) will have the opportunity to submit the dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Pending such resolution, the ISO shall have the authority to implement any such new Planning Procedures or modified Planning Procedures.

3.10 **Invoicing, Collection and Disbursement of Customer Payments.**

(a) Invoicing as of Operations Date. Except as provided in Section 3.10(a)(ii) and beginning on the Operations Date, the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO shall include the following (each, an "Invoiced Amount"):

(A) any and all revenue requirements, rates, charges, fees and/or penalties for Transmission Service under the ISO OATT and related service agreements which the PTOs have filed with FERC pursuant to Section 3.04(b) and which have been accepted by FERC, including without limitation recovery of wholesale or retail stranded costs, other than amounts billed directly by PTOs pursuant to Section 3.10(a)(ii) below; and

(B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by PTOs pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to Grandfathered Transmission Agreements, all services provided by a PTO pursuant to its Local Service Schedule on or after the Operations Date, interconnection agreements that provide for payment to PTOs, and any other payments made directly to the PTOs prior to the Operations Date shall continue to be invoiced by the PTOs and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, each PTO and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments

(iii) The ISO shall remit or credit to the PTOs, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement and directions provided to the ISO by the PTO Administrative Committee. The PTO Administrative Committee shall provide such directions to the ISO in accordance with the Disbursement Agreement among the PTOs. The

PTO Administrative Committee (or such subcommittee as the PTO Administrative Committee shall designate for such purpose) shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the decision of the PTO Administrative Committee unless and until it receives notification from the PTO Administrative Committee or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) Changes to the ISO OATT After Operations Date. After the Operations Date, the ISO may file with FERC proposed amendments to the ISO OATT in accordance with Section 3.04 to effect changes in the invoicing and collection of the charges specified in Section 3.10(a)(i), provided that the proposed amendments to the ISO OATT will not, without the consent of the PTOs:

(i) effect any changes relating to the ISO OATT requirements of letters of credit, deposits, and/or other financial assurances (collectively, the "Financial Assurances") to be provided by any party providing payments to the ISO in connection with the purchase of any goods or services provided by PTOs or any Market Participants (such parties, collectively, "ISO Customers") or the ISO that would in any way, individually or in the aggregate, materially reduce the level of collateral protection provided by Financial Assurances for Invoiced Amounts from that on the date of execution of this Agreement;

(ii) change the reallocation provisions under the ISO Tariff (including the ISO's billing policy thereunder) for payment defaults for Transmission Service;

(iii) change any reallocation provisions under the ISO Tariff (including the ISO's billing policy thereunder) for payment defaults for any services or products under the ISO Tariff other than Transmission Service in any way that imposes any obligation on the PTOs, in their capacity as owners of Transmission Facilities, to bear any costs of that reallocation of payment defaults;

(iv) lower the PTO's priority in payments for amounts collected by the ISO; or

(v) be inconsistent with any provision of this Agreement.

(c) The ISO's Collection Obligations and Application of Financial Assurances Policies.

(i) If a Transmission Customer defaults on any payment of any PTO Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(ii) In connection with a default on payment of an Invoiced Amount by a Transmission Customer, the ISO shall, upon the request of the PTO AC, take those actions necessary to suspend Transmission Services to such defaulting Transmission Customer, including making a filing under Section 205 of the Federal Power Act to seek consent to suspend such Transmission Services; provided that the ISO need not suspend Transmission Services until FERC approval is first obtained. This provision shall not preclude the ISO from suspending service or making a filing under Section 205 of the FPA to seek to suspend Transmission Services or other services under the Tariff in any other circumstances.

(d) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other change or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to the PTOs or any Financial Assurances.

3.11 **Grandfathered Transmission Agreements.**

(a) Notwithstanding any other provision of this Agreement, Excepted Transactions will remain in effect for the terms of such agreements. Consistent with practice prior to the Operations Date, the ISO shall exercise its Operating Authority and otherwise fulfill its responsibilities under this Agreement in a manner that is consistent with and does not modify or abrogate the terms and conditions of such Excepted Transactions.

(b) Notwithstanding any other provision of this Agreement, Grandfathered Intertie Agreements, as set forth in Schedule 3.11(b), will remain in effect for the terms of such agreements. Consistent with practice prior to the Operations Date, the ISO shall exercise its Operating Authority and otherwise fulfill its responsibilities under this Agreement in a manner that is consistent with and that does not modify or abrogate the terms and conditions of such Grandfathered Intertie Agreements.

(c) Nothing in this Agreement shall require the modification or abrogation of Grandfathered Interconnection Agreements, as set forth in Schedule 3.11(c). Consistent with practice prior to the Operations Date, the PTOs agree to exercise their rights under Grandfathered Interconnection Agreements with generators to direct or request that generators take certain actions as needed to facilitate the exercise of Operating Authority by the ISO and the reliable operation of the New England Transmission System.

(d) All payments due to the PTOs under Grandfathered Transmission Agreements shall continue to be invoiced and collected by the PTOs in accordance with the terms of those agreements and shall not be invoiced or collected by the ISO. Notwithstanding the foregoing, each PTO and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(e) Nothing in this Agreement shall alter the standards, procedures or requirements applicable to the modification of any Grandfathered Transmission Agreement.

3.12 **Subcontractors.** Each PTO acknowledges and agrees that, subject to the terms set forth herein, including Section 6.07, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.12 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.13 **Municipal/Tax-Exempt Utilities.**

(a) The Parties to this Agreement hereby recognize the tax-exempt status of any tax-exempt bonds or other evidence of indebtedness of Publicly-Owned PTOs used to finance any Publicly-Owned PTO's Transmission Facilities. Nothing in this Agreement is intended to, and nothing in this Agreement should be construed in a manner that would, jeopardize the tax-exempt status of any tax-exempt bonds or other debt used to finance any Publicly Owned PTO's Transmission Facilities. The Parties to this Agreement contemplate that, as to Publicly-Owned PTOs, this Agreement will be deemed to be a "contract for the operation of an electric transmission facility by an independent entity" which "does not constitute private business use" of their Transmission Facilities under regulations of the Internal Revenue Service appearing, *inter alia*, in 26 C.F.R. § 1.141-7(g)(1)(ii) and subsequently adopted regulations of similar intent and coverage.

(b) In the event of a change in the nature of this Agreement that would jeopardize the tax-exempt status of any tax-exempt bonds or other debt used to finance Publicly-Owned PTO's Transmission Facilities, or a change in the state or federal income tax treatment of the arrangements contemplated by this Agreement, or any other set of circumstances, the effect of which would be to render the participation of Publicly-Owned PTOs in the arrangements established by this Agreement inconsistent with the maintenance of the tax-exempt status of bonds or other debt used to finance any Publicly-Owned PTO's Transmission Facilities, the Parties agree, if so requested, to undertake Commercially Reasonable Efforts to develop revised or replacement arrangements that will enable the Publicly-Owned PTOs to authorize the ISO to exercise Operating Authority over the Publicly-Owned PTOs' Transmission Facilities without incurring adverse state or federal income tax treatment of their outstanding bonds or other debt used to finance any Publicly-Owned PTO's Transmission Facilities, and will otherwise maintain the tax-exempt status of Publicly-Owned PTOs' outstanding bonds or other debt used to finance any Publicly-Owned PTO's Transmission Facilities. If, and to the extent that, the Parties to this Agreement are not able to accommodate the changes described in this subparagraph (b), the Parties will undertake Commercially Reasonable Efforts to develop an alternative means for Publicly-Owned PTOs to (i) transfer Operating Authority as to its Transmission Facilities to ISO-NE, and (ii) recover the costs of its PTF facilities in the same manner and by the same means as PTOs under this Agreement.

(c) In the event that an electric cooperative or membership corporation that owns PTF and has debt financed or guaranteed by the Rural Utilities Service ("RUS") of the United States Department of Agriculture (a "Cooperative TO") becomes a signatory to this Agreement, this Agreement shall become effective as to that Cooperative TO only upon approval of such participation by the RUS, to the extent required by RUS regulations, including those regulations currently codified at 7 C.F.R. § 1717.608 and subsequently adopted regulations of similar intent and coverage. Should such approval be denied or conditioned by the RUS in a manner unacceptable to the Cooperative TO, the other PTOs or the ISO, the other PTOs and the ISO will consult with the affected Cooperative TO and, if so requested, will undertake Commercially Reasonable Efforts to resolve to the extent practicable the objections articulated (and/or conditions imposed) by the RUS to the participation of the Cooperative TO in the arrangements contemplated by this Agreement. If, and to the extent that, the Parties to this Agreement are not able to accommodate the concerns expressed by the RUS as to the participation of such Cooperative TO, the Parties will undertake Commercially Reasonable Efforts to develop an alternative means for such Cooperative TO to (i) transfer Operating Authority as to its Transmission Facilities to ISO-NE, and (ii) recover the costs of its PTF facilities in the same manner and by the same means as PTOs under this Agreement.

(d) Nothing in this TOA or any other ISO agreement shall require any PTO on whose behalf Tax-Exempt Debt has been or will be issued, or which will issue Tax-Exempt Debt, to refund prior Tax-Exempt Debt or to violate restrictions applicable to facilities financed with Tax-Exempt Debt including contractual restrictions and covenants regarding use of such facilities.

(e) Nothing contained in this Agreement shall be construed to require any Publicly-Owned PTO: (i) to act in contravention of, or (ii) to refrain from acting where failure to act would be in contravention of, or (iii) to constitute consent or acquiescence by any Publicly-Owned PTO to any action or failure to act of any other Party in contravention of the laws of any State governing the organization or operation of the Publicly-Owned PTO.

3.14 **No Impairment of the ISO's Other Legal Rights and Obligations.**

Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs, provided that any such rights are not inconsistent with the express terms of this Agreement. During the Term of this Agreement, the ISO shall:

(a) have the rights and obligations to design, develop, operate, maintain and administer the New England Markets and congestion pricing mechanisms (including the exclusive right to make Section 205 filings relating to the Market Rules in accordance with Section 3.04),

(b) have the rights to undertake actions relating to congestion pricing and management in accordance with this Agreement, ISO Market Rules, and applicable FERC orders.

Nothing in this Agreement shall be deemed to impair or infringe on such rights and obligations.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of Each PTO.** As of the time of execution of this Agreement, each PTO, severally, represents and warrants to the ISO and each other PTO as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by such PTO of this Agreement have been duly authorized by all necessary and appropriate action on the part of such PTO; and this Agreement has been duly and validly executed and delivered by such PTO and constitutes the legal, valid and binding obligations of such PTO, enforceable against such PTO in accordance with its terms; provided, however, that as to Massachusetts Publicly-Owned PTOs, this representation and warranty shall not be binding unless and until they shall have first obtained a finally adjudicated declaratory ruling from the Massachusetts courts that the transfer of Operating Authority over their Transmission Facilities is lawful and permissible under the Massachusetts General Laws.

(c) No Breach. The execution, delivery and performance by such PTO of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which such PTO is a party which breach has a reasonable likelihood of materially and adversely affecting such PTO's performance under this Agreement.

(d) Transmission Facilities. Except as set forth on Schedule 4.01(d), such PTO has listed on one of Schedule 2.01(a) or Schedule 2.01(b), all of the transmission facilities with a voltage level of 69 kV or greater that it owns in the New England Control Area as of the Operations Date and all of the transmission facilities leased to it with a voltage level of 69 kV or greater in the New England Control Area as of the Operations Date.

(e) **NO WARRANTY REGARDING EACH PTO'S TRANSMISSION FACILITIES**. IN CONNECTION WITH EACH PTO'S GRANT OF

OPERATING AUTHORITY TO THE ISO OVER SUCH PTO'S TRANSMISSION FACILITIES PURSUANT TO THE TERMS OF THIS AGREEMENT, SUCH PTO'S TRANSMISSION FACILITIES ARE BEING MADE AVAILABLE PURSUANT TO THIS AGREEMENT TO THE ISO "AS IS, WHERE IS," AND SUCH PTO IS NOT MAKING ANY REPRESENTATIONS OR WARRANTIES, WRITTEN OR ORAL, STATUTORY, EXPRESS OR IMPLIED, CONCERNING SUCH TRANSMISSION FACILITIES, INCLUDING, IN PARTICULAR, ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, ALL OF WHICH ARE HEREBY EXPRESSLY EXCLUDED AND DISCLAIMED. THE FOREGOING PROVISION IS NOT INTENDED TO LIMIT OR CONDITION ANY OBLIGATIONS OF THE PTOS EXPRESSLY PROVIDED FOR ELSEWHERE IN THIS AGREEMENT.

4.02 **Representations and Warranties of the ISO.** As of the time of execution of this Agreement, the ISO represents and warrants to each PTO as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) No Breach. The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V

COVENANTS OF THE PTOS

5.01 **Covenants of Each PTO.** Each PTO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, such PTO shall comply with all covenants and provisions of this Article V, except to the extent the ISO and the number of PTOs necessary to amend this Agreement pursuant to Section 11.04(a) consent in writing to waive such covenants or performance is excused pursuant to Section 11.13(b).

5.02 **Financial Statements and Filings.** If a PTO's financial statements, permit applications or any other filing with any Governmental Authority are publicly available, such PTO shall, upon request by the ISO, provide the ISO information sufficient to allow the ISO to

locate such financial statements, permit applications or other filings, including the date and place of the filing of the relevant documents.

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by a PTO in connection with the negotiation of this Agreement shall be borne by such PTO; provided that nothing herein shall prevent such PTO from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) Each PTO shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by such PTO in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) Each PTO shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by such PTO. Each PTO shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by such PTO.

(c) Nothing in this Section 5.04 shall require any PTO to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** Each PTO shall notify the ISO and each other PTO in writing of, and contemporaneously provide the ISO and each other PTO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to such PTO, that causes or shall cause any covenant or agreement of such PTO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of such PTO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The PTO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to such PTO. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's or any other PTO's right to seek indemnity under Article IX.

ARTICLE VI

COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.13(b).

6.02 **Financial Statements and Filings.**

(a) To the extent not provided to stakeholders generally or made publicly available by the ISO, the ISO shall make available to each PTO: (i) quarterly unaudited financial statements within sixty (60) days after each quarter end and (ii) annual audited financial statements within one hundred twenty (120) days after each fiscal year end. In each instance, the financial statements made available by the ISO pursuant to (i) and (ii) above shall be prepared in accordance with Generally Accepted Accounting Principles and shall be true and correct in all material respects.

(b) If financial statements, permit applications or any other filing with any Governmental Authority are publicly available, the ISO shall, upon request by a PTO, provide such PTO information sufficient to allow such PTO to locate such financial statements, permit applications or other filings including the date and place of the filing of the relevant documents.

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **Consents and Approvals.**

(a) The ISO shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each PTO in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by the ISO in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) The ISO shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to performance of this Agreement by the ISO. The ISO shall promptly notify each PTO of any failure or anticipated failure to obtain any such consents and, if requested by such PTO, shall provide copies of all such consents obtained by the ISO.

(c) Nothing in this Section 6.04 shall require the ISO to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to discharge its obligations hereunder.

6.05 **Notice and Cure.** The ISO shall notify each PTO in writing of, and contemporaneously shall provide each PTO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of a PTO to seek indemnity under Article IX.

6.06 **Other PTOs.**

(a) The ISO shall not perform, or enter into an agreement to perform, any Operating Authority or other RTO functions set forth in Section 3.02 or any other portion of this Agreement for any transmission utility in the New England Control Area subject to the jurisdiction of FERC unless such transmission utility enters into and becomes a Party to this Agreement pursuant to Section 11.05; provided, however, that this Section 6.06 shall not apply to agreements with owners of ties to other Control Areas, agreements with owners of Merchant Facilities, agreements with generators (to the extent the ISO obtains operating authority over transmission tie lines owned by generators through such agreements), or agreements with Independent Transmission Companies.

(b) The ISO may enter into agreements to perform Operating Authority or other RTO functions for one or more transmission utilities in a Control Area outside of New England. If the ISO enters into an agreement to perform Operating Authority or other RTO functions for one or more transmission utilities in an area contiguous to the New England Control Area, such agreement shall not: (i) materially and adversely affect the ISO's ability to perform Operating Authority for any PTO, or (ii) be unduly preferential to any transmission utility similarly situated to any PTO; provided that, if a PTO believes that a proposed agreement to perform Operating Authority or other RTO functions for one or more transmission utilities in a Control Area contiguous to the New England Control Area violates the immediately foregoing proviso, such PTO may notify the ISO, within thirty (30) days after the receipt of the proposed agreement, of its desire to negotiate the additional or modified terms and conditions of this Agreement necessary to relieve said adverse effect or undue preference and if such negotiation is not concluded within thirty (30) days after said notice, either Party may seek to resolve the dispute in accordance with Section 11.14 of this Agreement and may file the additional or

modified terms and conditions of this Agreement necessary to relieve said adverse effect or undue preference for approval by the FERC. Notwithstanding anything else in this agreement, including Section 11.04, the PTO proposing any additional or modified terms and conditions of this Agreement shall not be required to demonstrate that the existing terms and conditions of this Agreement are unjust and unreasonable if the ISO has agreed to or the FERC approves the proposed additional or modified terms and conditions in an agreement with transmission utilities in a Control Area contiguous to the New England Control Area. The limitations and procedures in this Section 6.06(b) shall not apply to the ISO's execution and performance of Coordination Agreements (or amendments thereto) with the operators of neighboring Control Areas, to the administration of Interconnection Agreements with neighboring Control Areas, or to the ISO's provision of reliability services to New Brunswick Power Corporation.

(c) Nothing in this Agreement shall be construed as granting any FERC-jurisdictional Initial PTO or Additional PTO the right to recover the costs of its Transmission Facilities pursuant to the ISO OATT or any other regulated tariff absent approval or acceptance by the FERC for such cost recovery. The Parties hereto expressly reserve their rights to oppose a request for such cost recovery for any potential PTO that is not recovering its transmission costs pursuant to FERC regulated transmission tariffs prior to the Operations Date.

6.07 **Management Agreements.** The ISO shall not enter into any management agreement relating to the provision of transmission services with any Person, including a transmission-owning utility, unless such agreement: (a) has been approved by FERC; (b) does not violate the ISO's Code of Conduct and is on an arms-length basis; or (c) if for an aggregate amount of $1,000,000 or more for a contract with any Participant in the New England Markets, including PTOs, is the result of a competitive solicitation process, the outcome of which is based on factors that include, among others, skill, qualifications, costs, reputation, and associated risks.

6.08 **ISO Line of Business; Non-Profit-Status.** The ISO shall not be operated on a for-profit basis. This provision is not intended to require the ISO to maintain its status as an entity not subject to federal or state taxes, to require the ISO to remain a Delaware not-for-profit corporation or to assure that in any particular year that the ISO's revenues do not exceed its expenses. The ISO shall not pay dividends or use its net earnings other than to offset ISO operating and capital expenses and maintain reasonable reserves.

ARTICLE VII

TAX MATTERS

7.01 **Responsibility for PTO Taxes.** Each PTO shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for any PTO and shall have no liability for any Taxes related to any PTO's Transmission Business or Transmission Facilities. No PTO shall be responsible for, or required to file, any Tax Returns or other reports for any other PTO and shall have no liability for any Taxes related to any other PTO's

Transmission Business or Transmission Facilities. The ISO and each PTO hereby agree that, for tax purposes, a PTO's Transmission Facilities shall be deemed to be owned by such PTO.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. No PTO shall be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII

RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of each other Party contained in this Agreement. The provisions of Sections 11.01, 11.09, 11.13 and 11.17 and Articles VII and IX shall survive the termination of this Agreement. With respect to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX

INDEMNIFICATION; INSURANCE; LIMITATION OF LIABILITIES

9.01 **Indemnification.**

(a) Subject to Section 9.06(b) through 9.06(e), (i) each PTO shall severally release, indemnify, and hold harmless the ISO from and against any and all damages, losses, liabilities, obligations, claims, demands, suits, proceedings, recoveries, judgments, settlements, costs and expenses, court costs, attorney fees, and all other obligations (each, an "Indemnifiable Loss") asserted against the ISO by a Person that is not a Party to this Agreement (a "Third Party") including but not limited to any action by a PTO employee, to the extent alleged to result from, arise out of or be related to such PTO's acts or omissions that give rise to such Indemnifiable Loss; and (ii) the ISO shall release, indemnify, and hold harmless each PTO from and against any Indemnifiable Loss asserted against such PTO by a Third Party, including but not limited to any action by an ISO employee, to the extent alleged to result from, arise out of or be related to the ISO's acts or omissions that give rise to such Indemnifiable Loss, including an ISO directive and/or instructions to a Party.

(b) The indemnification by the ISO set forth in Section 9.01(a)(ii) above shall be limited to the extent that the liability of a PTO seeking indemnification would be limited by any applicable Law and arises from a claim by (i) such PTO in such PTO's role as a Transmission Customer or (ii) a customer of such PTO.

(c) Each PTO shall severally release, indemnify, and hold harmless the ISO from and against any Environmental Damages that the ISO becomes subject to as a result of its exercise of Operational Authority over such PTO's Transmission Facilities, to the extent such Environmental Damages arose prior to the Operations Date or did not result from the ISO's acts or omissions.

(d) Each PTO and/or the ISO each hereby (i) waives any defense or immunity it might otherwise have under applicable workers' compensation laws or any other statute, or judicial decision, disallowing or limiting such indemnification and (ii) consents to a cause of action for indemnity and/or contribution in connection with such indemnification.

9.02 **Notice of Proceedings.** Each party entitled to receive indemnification under this Agreement (each, an "Indemnitee") shall promptly notify the party who holds an indemnification obligation hereunder (in each case, the "Indemnifying Party") of any Indemnifiable Loss in respect of which such Indemnitee is or may be entitled to indemnification pursuant to Section 9.01. Such notice shall be given as soon as reasonably practicable after the Indemnitee becomes aware of the Indemnifiable Loss and that any such claim or proceeding may give rise to an indemnification obligation hereunder. Such notice shall describe the nature of the loss or proceeding in reasonable detail and shall indicate, if practicable, the estimated amount of the Indemnifiable Loss that has been or may be sustained by the Indemnitee. The delay or failure of such Indemnitee to provide the notice required pursuant to this Section 9.02 shall not release the Indemnifying Party from any indemnification obligation which it may have to such Indemnitee except (a) to the extent that such failure or delay materially and adversely affects the Indemnifying Party's ability to defend such action or increases the amount of the Indemnifiable Loss, and (b) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnitee in the defense of the claim, suit, action or proceeding during such period of failure or delay.

9.03 **Defense of Claims**.

(a) Unless and until the Indemnifying Party (i) acknowledges in writing its obligation within ten (10) calendar days of the Indemnitee's notice of a claim, suit, action or proceeding, and (ii) assumes control of the defense of such claim, suit, action or proceeding in accordance with Section 9.03(b), the Indemnitee shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Indemnitee in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(b) Upon acknowledging in writing its obligation to indemnify an Indemnitee to the extent required pursuant to this Article IX and paying all reasonable costs incurred by such Indemnitee in its defense, including reasonable attorney's fees, the Indemnifying Party shall be entitled, at its option (subject to Section 9.03(d)), to assume and control the defense of such

claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior reasonable approval of the Indemnitee.

(c) Neither the Indemnifying Party nor the Indemnitee shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior written consent of the other; provided, however, that such consent shall not be unreasonably withheld.

(d) Following the acknowledgment of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to Section 9.03(b), the Indemnitee shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of such Indemnitee, when and as incurred, unless: (i) the employment of counsel by such Indemnitee has been authorized in writing by the Indemnifying Party; (ii) the Indemnitee shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnitee in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnitee to assume the defense of such action and shall have been so notified by the Indemnitee; (iv) the Indemnitee shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnitee beyond the scope of this Agreement; or (v) the Indemnifying Party shall not have taken reasonable steps necessary to defend diligently such action within twenty (20) calendar days after receiving notice from the Indemnitee that the Indemnitee believes the Indemnifying Party has failed to take such steps. If clause (ii), (iii), (iv) or (v) of the preceding sentence shall be applicable, then counsel for the Indemnitee shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnitee and the reasonable fees and disbursements of such counsel shall constitute indemnifiable legal or other expenses hereunder.

(e) If the amount of any Indemnifiable Loss incurred by an Indemnitee, at any time subsequent to the making of an indemnity payment by an Indemnifying Party in respect thereof, is reduced by recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other entity, the amount of such reduction, less any costs, expenses or premiums incurred in connection therewith (together with interest thereon from the date of payment thereof at the Prime Rate) shall promptly be repaid by the Indemnitee to the Indemnifying Party. In the event that the claim, demand or suit giving rise to an Indemnifiable Loss is ultimately adjudicated, if a Final Order confirms that the Indemnitee was not entitled to indemnification hereunder, then the amount advanced by the Indemnifying Party in respect of such Indemnifiable Loss (together with interest thereon from the date of payment thereof at the Prime Rate) shall promptly be paid by the Indemnitee to the Indemnifying Party.

9.04 **Subrogation.** Upon payment of any indemnification by a party pursuant to this Article IX, the Indemnifying Party, without any further action, shall be subrogated to any and all claims that the Indemnitee may have relating thereto, and such Indemnitee shall at the request and expense of the Indemnifying Party cooperate with the Indemnifying Party and give at the request and expense of the Indemnifying Party such further assurances as are necessary or advisable to enable the Indemnifying Party vigorously to pursue such claims.

9.05 **Insurance.**

(a) The ISO shall at all times, at its own cost and expense, carry and maintain or cause to be carried and maintained throughout the Term: (i) liability and errors and omissions insurance (including blanket coverage for contractual liability), insuring the ISO against liability for injury or death to persons, damage to property and environmental restoration, (ii) worker's compensation insurance, (iii) property insurance and (iv) directors' and officers' insurance. The amount of the insurance coverages and deductibles shall generally be comparable to other independent system operators or RTOs, taking into consideration the relative size of the ISO and its contractual and tariff liabilities as compared to the other system operators or RTOs administering similar market structures. In assessing the comparable coverages and deductibles, the ISO may rely on the advice of its insurance consultants.

(b) Each PTO will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice. Each PTO may self insure such amount to the extent it currently self insures similar policies and amounts.

I All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the PTOs and the ISO.

(d) The PTOs shall be listed as additional insured parties on the liability and errors and omissions insurance required to be maintained by the ISO and the ISO shall be listed as an additional insured party on the liability insurance maintained by each PTO. Upon execution of this Agreement, and when requested thereafter, each Party shall furnish each other Party with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

(e) The insurance policies maintained by the ISO hereunder shall not be canceled, terminated or the terms thereof modified or amended without at least thirty (30) days' prior notice to the PTOs.

(f) If any insurance policy required to be maintained by the ISO hereunder shall not be available to the ISO on a commercially reasonable basis (taking into account both

terms and premiums), the ISO shall obtain a written report of an independent insurance advisor of recognized national standing, chosen by the PTOs and reasonably acceptable to the ISO, confirming in reasonable detail that such insurance policy, in respect of amount or scope of coverage, is not available on a commercially reasonable basis from insurers of recognized standing. During any period with respect to which any insurance policy required by this Agreement is not commercially available, the ISO shall nevertheless maintain insurance that approximates such required insurance policy as closely as commercially practical, to the extent it is available on a commercially reasonable basis from insurers of recognized standing. If any insurance policy which was previously not held or discontinued because of its commercial unavailability later becomes available on a commercially reasonable basis, the ISO shall obtain or reinstate such insurance.

9.06 **Assumption of Liability.**

(a) (i) Each PTO shall be severally liable to the ISO, and the ISO shall be liable to each PTO, for losses, liabilities, damages, diminution in value, obligations, claims, proceedings, fines, deficiencies and expenses (collectively, "Losses") caused by such Party's grossly negligent acts or omissions or willful misconduct (including the grossly negligent acts or omissions or willful misconduct of such Party's directors, Affiliates, members, officers, employees, agents, and contractors) in connection with the performance of such Party of its obligations under this Agreement; and (ii) no Party shall be liable to another Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy. The foregoing limitations shall not apply to the right of the Parties to seek indemnification under this Agreement in accordance with Section 9.01.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

I The ISO shall not be liable to any PTO with respect to any damages incurred by such PTO that are directly attributable to the ISO's reliance on facility ratings established by such PTO.

(d) No PTO shall be liable to any other PTO and/or the ISO by reason of this Agreement (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for: (i) any acts or omissions taken or done in compliance with, or good faith attempts to comply with, the directives and/or instructions of the ISO, except in cases of the gross negligence or willful misconduct of such PTO; and/or (ii) any costs and expenses relating to the operation, repair, maintenance or improvement of any Transmission Facility of the ISO or any other PTO.

(e) Notwithstanding any of the foregoing, the ISO shall be liable in actual damages for failure to make payments or transfer sums under Section 3.10 of this Agreement if the ISO fails to discharge its obligation to prepare and send bills or to perform its obligations pursuant to Section 3.10 of this Agreement.

ARTICLE X

TERM; DEFAULT AND TERMINATION

10.01 **Term; Termination Date.**

(a) Term and Operations Date.

(i) Term. Subject to the terms set forth in this Section 10.01, the initial term of this Agreement (the "Initial Term") shall commence on the Operations Date and shall continue for a period of five years. Subject to the terms set forth in this Section 10.01, the Initial Term shall be extended automatically for additional two-year periods (each, an "Additional Term"). Any one or more PTOs may withdraw from this Agreement effective at the end of the Initial Term or the end of any Additional Term by providing no less than 180 days' prior notice of such withdrawal to the other Parties. Together, the Initial Term and the Additional Term(s), if any, shall constitute the term (the "Term") of this Agreement.

(ii) Operations Date. The "Operations Date" shall be the date on which the ISO and the Initial Participating Transmission Owners unanimously agree to place this Agreement, the ISO OATT, and related agreements and documents into effect. The ISO and the Initial Participating Transmission Owners shall jointly issue a written notice (the "Notice of Operations Date") at least thirty (30) calendar days in advance of the Operations Date. The Notice of Operations Date shall be posted on the ISO website and filed with FERC on an informational basis.

(b) PTO Withdrawal During The Term. Subject to Section 10.01(e), any one or more PTOs may withdraw from this Agreement at any time during the Term if any of the following shall have occurred:

(i) upon an ISO event of default in accordance with Section 10.03(a), provided that the PTOs shall exercise this right in accordance with Section 10.03(b)(i).

(ii) if a Final Order of FERC, a Final Order of a Federal court or a Federal law sets forth a change in policy stating that: (A) the federal government no longer encourages the participation of transmission owners in RTOs and such Final Order or law affirmatively states that transmission owners participating in an RTO may withdraw therefrom, or (B) that the recovery of costs for existing

Transmission Facilities will be subject to any change in policy which would prevent a PTO from recovering the costs of existing Transmission Facilities on a regulated cost-of-service basis; provided that withdrawal pursuant to (A) or (B) of this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e).

(iv) FERC issues an order putting into effect changes to the relative rights and responsibilities of the PTOs and the ISO under this Agreement, including changing the scope and definition of Operating Authority, so as to materially adversely affect the interests of one or more PTOs, unless the PTOs have agreed to such changes in accordance with Section 11.04; provided that: (A) only the PTO(s) affected by such FERC order shall have the right to withdraw pursuant to this provision; (B) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (C) a PTO providing a notice of withdrawal pursuant to this provision shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the changes to the relative rights and responsibilities of the PTOs and the ISO under this Agreement.

(v) the withdrawing PTO has entered into an agreement to form an ITC in accordance with Attachment M to the ISO OATT which has been accepted for filing by the FERC, provided that withdrawal pursuant to this provision shall be effective concurrent with the effective date of such agreement.

(vi) the withdrawing PTO has obtained authorization from the FERC to join another RTO or other similar organization (such as an Independent System Operator) in connection with a merger with or acquisition by another entity other than another PTO.

I Remaining PTOs. In the event that one or more, but less than all, PTOs withdraw from this Agreement in accordance with Section 10.01(a) or (b), this Agreement shall remain in full force and effect with respect to all other PTOs; provided that in the event of a withdrawal under Section 10.01(a), the remaining PTOs shall have a period of twenty days from the date of the notice provided in accordance with Section 10.01(a) to notify the other Parties that it intends to withdraw from this Agreement at the end of the Initial Term or any Additional Term, as applicable. The "Termination Date" shall mean the date of termination established in accordance with Section 10.01(e).

(d) Termination By the ISO. The ISO may terminate its obligations under this Agreement and surrender its Operating Authority over the Transmission Facilities if any of the following shall have occurred:

(i) the withdrawal of one or more PTOs from this Agreement and as a result of such withdrawal the ISO cannot maintain system reliability or administer efficient and competitive markets.

(ii) FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO OATT, provided that: (A) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (B) the ISO shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the material changes to such liability and indemnification protections.

(iii) FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO's ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04, provided that: (A) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (B) the ISO shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the material adverse effect to the ISO's ability to carry out its responsibilities under this Agreement.

(iv) upon a PTO event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i).

(e) Actions Prior To Withdrawal or Termination. Upon submission of a written notice of termination or withdrawal by a Party or Parties, the Party or Parties submitting such notice shall commence the development of a plan under which Operating Authority shall be transferred from the ISO to another entity. The Termination Date with respect to any PTO or the ISO shall not occur until both: (a) the ISO and all affected PTOs have agreed upon a plan addressing the technical, operational and market issues associated with the transfer of Operating Authority in connection with such termination or withdrawal and such plan has been implemented, provided that: (i) if the Parties are unable to reach agreement on such plan, any affected Party shall have the right to submit the matter to FERC for resolution without additional negotiation under Section 11.14; (ii) with respect to a withdrawal pursuant to Section 10.01(a), no PTO shall be required to remain a Party to this Agreement for longer than one year after providing notice of withdrawal; and (iii) in the event of a default by the ISO, the affected PTOs may require that the ISO immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to such PTOs prior to the Termination Date in accordance with Section 10.03(b); and (b) all required regulatory approvals, if

any, have been obtained for such withdrawal or termination, including any approvals required pursuant to Section 10.01(f).

(f) Approvals. Notwithstanding any other provision contained herein or in any other document to the contrary, any termination or withdrawal requested under this Section 10.01 shall be effective: (1) unless a party to this Agreement seeking to challenge the request demonstrates that the requested termination or withdrawal is contrary to the public interest under the Mobile-Sierra Doctrine and (ii) subject to the FERC's determination under Section 205 of the Federal Power Act that the termination or withdrawal is just, reasonable and not unduly discriminatory or preferential. Each PTO exercising its right to withdraw or terminate in accordance with this Section 10.01 shall file with the FERC, pursuant to Section 205 of the FPA, the tariffs and rate schedules applicable to transmission service over such PTO's Transmission Facilities to become effective upon such termination or withdrawal.

(g) Continuing Obligations. Each withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement

(i) All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and each other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

(ii) Any withdrawing PTO that is not a Publicly-Owned PTO shall file a replacement transmission tariff to replace the ISO OATT, unless FERC rules no longer require the filing of such a tariff. Any withdrawing Publicly-Owned PTO shall adopt the Order No. 888 pro forma tariff.

10.02 **Release of Operating Authority**.

(a) Upon the Termination Date, the ISO's right and obligation to exercise Operating Authority over the Transmission Facilities of a PTO with whom this Agreement has terminated shall promptly cease, and, in accordance with Section 10.01, the ISO shall be deemed to have released and returned, and such PTO (or its designee) shall have assumed, Operating Authority over such Transmission Facilities on the Termination Date.

(b) After the Termination Date, the ISO shall take Commercially Reasonable Efforts to assist the terminating PTO or such PTO's designee in resuming performance of the functions comprising Operating Authority.

(c) The expenses associated with any termination under Section 10.01 shall be at the PTO's expense unless (1) the termination is by the ISO pursuant to Section 10.01(d)(ii) or (iii), or (2) pursuant to Section 10.03 in the event of an ISO default.

10.03 **Events of Default of the ISO.**

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from a PTO; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by all affected Parties

(ii) If there is a dispute between the ISO and a PTO as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to any PTO by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) Failure of the ISO to pay when due any other amounts payable to any PTO by the ISO pursuant to this Agreement within thirty (30) days of the due date;

(vi) The exercise of Operating Authority or other responsibilities under this Agreement in a manner that results in a material amount of damage to or the destruction of a PTO's Transmission Facilities due to the willful misconduct or gross negligence of the ISO or the repeated and persistent exercise by the ISO of its Operating Authority in a manner that subjects Transmission Facilities to the significant risk of a material amount of damage, provided that exercise by the ISO of its Operating Authority over any Transmission Facility both in accordance with the Operating Procedures and within the ratings established by a PTO for such Transmission Facility shall not be considered to subject such Transmission Facility to risk of damage and further provided that nothing in this Section 10.03(a)(v) shall be deemed to excuse the ISO from complying with its obligations under this Agreement or to limit the other events of default specified in this Section 10.03(a).

(vii) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, each affected PTO shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate its participation in this Agreement with respect to such PTO in accordance with Section 10.01(e); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall immediately make arrangements for the orderly transfer of Operating Authority over such PTO's Transmission Facilities and assist such PTO or such PTO's designee in resuming performance of the functions comprising Operating Authority, provided that: (A) such PTO shall not be liable for the reimbursement of the ISO for any costs and expenses incurred by the ISO in connection therewith; (B) the ISO and all affected PTOs shall agree upon a plan addressing the technical and operational issues associated with such transfer of Operating Authority, and such plan has been implemented; and (C) if the Parties are unable to reach agreement on such plan, any affected Party shall have the right to submit the matter to FERC for resolution without additional negotiation under Section 11.14;

(iii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to such PTO and assist such PTO or such PTO's designee in resuming performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle. Without limiting the generality of the foregoing, the ISO agrees to deliver all information and files necessary to perform billing for regional transmission service (the "Regional Billing"), including but not limited to transferring all files then used by the ISO to prepare rate calculations and billing to a billing representative designated by the PTOs. The PTOs will provide the ISO, within 30 days of the Operations Date, with a list of the specific information and files necessary if the PTOs were to perform the Regional Billing;

(iv) To make any payment or perform or comply with any agreement that the ISO shall be obligated to pay, perform or comply with under this Agreement and the amount of reasonable expenses (including attorneys' fees and any other reasonable professionals' fees and expenses) of such PTO incurred in connection with such payment or the performance of or compliance with any such agreement shall be payable by the ISO upon demand;

(v) To obtain such specific performance and/or an injunction to prevent breaches of this Agreement and to enforce specifically the terms and conditions hereof; and/or

(vi) To obtain damages pursuant to the indemnity provisions of Sections 9.01 and 9.06 and for non-performance of invoicing/payment obligations under Section 3.10 of this Agreement.

10.04 **Events of Default of a PTO.**

(a) Events of Default of a PTO. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of such PTO under this Agreement (in each instance, a "PTO Default"):

(i) Failure by such PTO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by such PTO of written notice of such failure from the ISO, provided, however, that if such PTO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by all affected Parties;

(ii) If there is a dispute between a PTO and the ISO as to whether the PTO has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) With respect to such PTO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by such PTO for the benefit of creditors; or (C) allowance by such PTO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment; or

(iv) Failure of the PTO to pay when due any amounts payable to the ISO by such PTO pursuant to this Agreement within thirty (30) days of the due date.

(b) Remedies for Default. If an event of default by a PTO occurs , the ISO shall have the following remedies, all of which shall be cumulative and not exclusive:

(i) terminate this Agreement with respect to such PTO in accordance with Section 10.01(e); provided that if such PTO contests such allegation of a PTO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) such specific performance and/or an injunction to prevent breaches of this Agreement and to enforce specifically the terms and conditions hereof; or

(iii) obtain damages pursuant to the indemnity provisions of Sections 9.01 and 9.06.

(c) Notwithstanding anything to the contrary herein, nothing in this Section 10.04 shall be deemed to give the ISO or any ISO agent or designee the right to exercise any functions other than those enumerated as Operating Authority in Section 3.02 or the right to take physical control of any PTO facilities.

ARTICLE XI

MISCELLANEOUS

11.01 **Notices.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to each party and copy party hereto at its address set forth in Schedule 11.01 or, in the case of any such party or copy party hereto, at such other address as such party or copy party may from time to time designate by written notice to the other parties hereto; further provided that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **Supersession of Prior Agreements.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters, including those agreements set forth on Schedule 11.02 attached hereto. To the extent that such other agreements address subjects addressed in this Agreement, this Agreement shall govern.

11.03 **Waiver.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **Amendment; Limitations on Modifications of Agreement.**

(a) Except as otherwise specifically provided herein, this Agreement shall only be subject to modification or amendment as follows:

(i) Establishment of Committee. The PTOs shall form a PTO Administrative Committee ("PTO AC") which shall meet periodically (1) to consider recommendations to the ISO regarding actions, policies and rules of the ISO affecting the PTOs' Transmission Facilities; (2) to consider and vote upon proposed amendments to this Agreement; (3) to consult with the ISO as may be provided for under this Agreement; and (4) to consider any other matters relating to the administration of this Agreement by the PTOs. The PTO AC shall be organized in the manner described in Schedule 11.04.

(ii) Amendments to Section 11.04(a)(iii) and Schedule 11.04. Notwithstanding anything in this Agreement which may be construed to the contrary, the PTOs may unilaterally amend or revise Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement through a vote of the PTO AC as set forth in Section 12 of Schedule 11.04, without the consent of the ISO, and may submit such amended Agreement under Section 205 of the Federal Power Act. Notwithstanding anything in this Agreement which may be construed to the contrary, the ISO may unilaterally amend or revise section 11.04(a)(iii)(A) of this Agreement through the process set forth in that subsection, without the consent of the PTOs, and may submit such amended Agreement under Section 205 of the Federal Power Act.

(iii) Amendments to this Agreement. Except as set forth in section 11.04(a)(ii), this Agreement may be amended by mutual agreement of the PTOs and the ISO and the acceptance of any such amendment by FERC.

(A) ISO Agreement to Amendments. The ISO shall be deemed to have agreed to such amendment upon execution of the amendment.

(B) PTO Agreement to General Amendments. Except as otherwise provided in sections 11.04(a)(iii)(C) and 11.04(a)(iii)(D), the PTOs will be deemed to have agreed to

such amendment upon a vote of the PTOs meeting all of the following criteria:

(1) Weighted Voting. A vote to approve an amendment to this Agreement under this Section 11.04(a)(iii)(B) shall be cast by a number of the Individual Votes of the PTOs equal to or greater than sixty-five (65) percent of the aggregate Individual Votes of all the PTOs;

(2) Support of Non-Affiliated PTOs. In addition to the Individual Votes satisfying Section 11.04(a)(iii)(B)(i), a vote of the PTOs to approve an amendment to this Agreement under this Section 11.04(a)(iii)(B) shall be cast by a number of Non-Affiliated PTOs that have Supporting Votes that are equal to or greater than (x) fifty (50) percent of such Non-Affiliated PTOs or (y) four (4), whichever is less; and;

(3) Limits on a Single PTO Veto. The negative vote of a single PTO with Individual Votes equal to thirty-five (35) but not more than fifty (50) percent of the aggregate Individual Votes of the PTOs shall not cause the amendment to fail if the combined Individual Votes of the PTOs voting in favor of the amendment are equal to or greater than ninety-five (95) percent of the Individual Votes of all the remaining PTOs. The negative vote of a single PTO with Individual Votes greater than fifty (50) percent of the aggregate Individual Votes of the PTOs voting shall cause the amendment to fail.

(C) PTO Agreement Requiring a Super Majority Vote. The PTOs will be deemed to have agreed to an amendment to Section 3.04(b) of this Agreement upon a vote of the PTOs meeting both of the following criteria:

(1) Weighted Voting. A vote to approve an amendment to section 3.04(b) of this Agreement shall be cast by a number of the Individual Votes of the PTOs equal to or greater than ninety-five (95) percent of the aggregate Individual Votes of all the PTOs; and

(2) Support of Non-Affiliated PTOs. In addition to the Individual Votes satisfying Section 11.04(a)(iii)(C)(i), a vote of the PTOs to approve an amendment to section 3.04(b) of this Agreement shall be cast by a number of Non-Affiliated PTOs that have Supporting Votes-that are equal to or greater than (x) seventy (70) percent of such Non-Affiliated PTOs or (y) five (5),whichever is less.

(D) PTO Agreement Requiring Consent of Affected Party. Notwithstanding anything in this Agreement which may be construed to the contrary, the PTO rights and privileges contained in sections 2.01, 3.04(a), 3.04(j), 3.04(k), 3.07, 3.13, 10.01(a), 10.01(b), and 11.04 of this Agreement and sections 12 and 13 of Schedule 11.04 to this Agreement shall not be modified or diminished by amendment to this Agreement or in any other way without the prior written consent of each PTO that may be affected thereby.

(E) Amendments to PTO Voting Provisions to Reflect Additional Participating Transmission Owners. If an unaffiliated transmission utility from outside the New England Control Area becomes or is about to become an Additional Participating Transmission Owner pursuant to Section 11.05 of this Agreement, and if any initial PTO's Individual Vote will change by more than 20 percent as a result, the PTOs shall enter into good faith negotiations to consider appropriate modifications to Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement. The PTOs may unilaterally amend or revise Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement through a vote of the PTO AC as set forth in Section 11.04(a)(iii)(D), without the consent of the ISO, and may submit such amended Agreement to the FERC under Section 205 of the Federal Power Act.

(F) Supporting Votes. Each PTO that has a minimum of one (1) percent of the aggregate Individual Votes of all the PTOs at the time of the applicable PTO AC meeting shall have a single "Supporting Vote." The Individual Votes of any group of two or more PTOs that each have an Individual Vote of less than one (1) percent may be combined and voted so that if the combined Individual

Votes of such PTOs are equal to or greater than one (1) percent of the aggregate Individual Votes of all the PTOs at the time of the applicable PTO AC meeting, such combined Individual Votes shall be counted as a single Supporting Vote. Subject to a sufficient number of Publicly-Owned PTOs executing this Agreement, as of the Operations Date the combined Individual Votes of all of the Publicly-Owned PTOs is expected to be greater than one (1) percent of the aggregate Individual Votes of all the PTOs. In the event that the combined Individual Votes of all of the Publicly-Owned PTOs as of the Operations Date is greater than one (1) percent of the aggregate Individual Votes of all the PTOs, if at any time after the Operations Date, all of the Publicly-Owned PTOs have Individual Votes of less than one (1) percent of the aggregate Individual Votes of all of the PTOs due to the addition of new transmission assets and the depreciation of existing transmission assets, then the combined Individual Votes of all of the Publicly Owned PTOs shall nonetheless be counted as a single Supporting Vote.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

(c) Absent the agreement of the Parties to any proposed change hereof or an amendment hereof pursuant to Section 11.04(a), the standard of review for changes to the following sections of this Agreement (or changes to any schedules associated with such sections) proposed by a Party, a non-party or the Federal Energy Regulatory Commission acting sua sponte shall be the "public interest" standard of review under the Mobile-Sierra Doctrine: 2.01, 2.04, 3.01, 3.02, 3.03, 3.04, 3.05, 3.06, 3.07, 3.09, 3.10, 3.11, 3.13, 3.14, 4.01(e), 6.06, 6.07, 6.08, 9.01, 9.06, 10.02, 10.03, 10.04, 11.04(a) - (d), 11.05, 11.06, 11.08, 11.17, 11.19(d), and Article I, as it applies to the foregoing sections. Absent the agreement of the Parties to any proposed change hereof or an amendment hereof pursuant to Section 11.04(a), with respect to changes to the remaining provisions of this Agreement proposed by a Party, a non-party or the Federal Energy Regulatory Commission acting sua sponte, the standard of review shall be that provided under Section 206 of the Federal Power Act.

(d) Notwithstanding the Parties' rights under Section 3.04 hereof, neither the ISO nor any PTO shall propose to modify or amend the ISO OATT nor any other tariff, rate schedule, procedure, protocol, or agreement applicable to the ISO or the PTOs in any manner that would limit, alter, or adversely affect the rights and responsibilities of the non-proposing

Parties under this Agreement or that would otherwise be inconsistent with the provisions of this Agreement unless: (i) the PTOs and the ISO have entered into a prior written agreement to make corresponding modifications to this Agreement in accordance with this Section 11.04, or (ii) if corresponding modifications to the provisions of this Agreement enumerated in Section 11.04(c) above are required, the proposing Party also requests FERC to find (or FERC has already so found) that the corresponding modifications are required under the "public interest" standard of review under the Mobile-Sierra Doctrine or (iii) if corresponding modifications to the remainder of the Agreement are required, the proposing Party also requests FERC to find (or FERC has already so found) that the corresponding modifications are required under the standard of review under Section 206 of the Federal Power Act.

(e) The Parties shall notify stakeholders of proposed amendments to this Agreement by posting such amendments on the ISO website prior to the filing of such amendments with FERC and shall consider stakeholder input concerning such proposed amendments.

11.05 **Additional Participating Transmission Owners.** After the Operations Date, subject to the terms set forth herein, including Section 6.06, any owner of transmission facilities may become a PTO under this Agreement and a Party to this Agreement by executing and delivering a counterpart to this Agreement with the consent or approval of the ISO, such consent or approval not to be unreasonably withheld. Owners of transmission facilities that become PTOs pursuant to the terms of this Section 11.05 shall be referred to herein as "Additional Participating Transmission Owners"; provided, however, that, notwithstanding any other provision contained herein to the contrary, Independent Transmission Companies shall not be deemed to be Additional Participating Transmission Owners hereunder. Notwithstanding Section 11.04 or any other provision contained herein to the contrary, Additional Participating Transmission Owners may become parties to this Agreement without any consent or approval of the other PTOs and without any amendment to this Agreement, except that this Agreement may be amended pursuant to Section 11.04(a)(iii)(E) if an unaffiliated transmission utility from outside the Control Area becomes or is about to become an Additional Participating Transmission Owner.

11.06 **Integration Charges.** Each Additional Participating Transmission Owner that enters into this Agreement after the Operations Date shall pay upon joining or shall promptly reimburse the ISO and each affected PTO for (a) all incremental costs, expenses and charges (including those incurred by the ISO or other PTOs) that, as determined by the ISO, result from the integration of such PTO's transmission system into the Transmission Facilities over which the ISO exercises Operating Authority and produce an increase in ISO Administrative Charges assessed against users of the New England Transmission System; and (b) such PTO's Pro Rata Share of the aggregate start-up costs recovered up to that date by the ISO. The ISO shall not implement any integration until it has received from the Additional Participating Transmission Owner payment in full for all such payments or secured a binding agreement that obligates the Additional Participating Transmission Owner to pay all such costs, expenses and other charges as they come due.

11.07 **No Third Party Beneficiaries.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.08 **No Assignment; Binding Effect.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party (including by operation of law) without the prior written consent of each other Party in its sole discretion and any attempt at assignment in contravention of this Section 11.08 shall be void. Any PTO may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) the PTO's successors and assigns shall agree to be bound by the terms of this Agreement except that PTO's successors and assigns shall not be required to be bound by any obligations hereunder to the extent that the PTO has agreed to retain such obligations; and

(b) notwithstanding (a), the PTO shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No assignment shall be effective until the PTO receives all required regulatory approvals for such assignment.

11.09 **Further Assurances; Information Policy; Access to Records**.

(a) Each Party agrees, upon another Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon a PTO's request, make available to such PTO any and all information within the ISO's custody or control that is necessary for such PTO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to such PTO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any PTO employee or employee of a PTO's Local

Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for a PTO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.14 of this Agreement.

(c) Each PTO shall, upon the ISO's request, make available to the ISO any and all information within the PTO's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.14 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or any PTO be furnished with additional information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the ISO or a PTO, the ISO or such PTO shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or such PTO's request, cost and expense. Any information obtained by the ISO or a PTO in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.09:

(i) no Party shall be obligated by this Section 11.09 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.09;

(ii) if any PTO and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.09), the furnishing of information, documents or records by the ISO or such PTO in accordance with this Section 11.09 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement, diminishes any other Party's obligations under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.10 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.11 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.12 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such party or its respective successors or assigns in connection with any such action or proceeding; provided, however, that nothing in this Section 11.12 shall affect the right of any such Parties or their respective successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Parties or their respective successors and assigns to bring any action or proceeding against any other one of such Parties or its respective property in the courts of other jurisdictions.

11.13 **Specific Performance; Force Majeure.**(a) Specific Performance. The Parties specifically acknowledge that a breach of this Agreement, whether or not an Event of Default, and notwithstanding any cure period in Section 10.03(b), would cause each of the non-breaching Parties to suffer immediate and irreparable harm due to the unique relationship among the Parties. The Parties hereto shall be entitled to seek specific performance and/or an injunction or injunctions to prevent breaches of the provisions of this Agreement and to enforce specifically the terms and conditions hereof in any court of competent jurisdiction, such remedy being in addition to any other remedy to which any Party may be entitled at law or in equity.

(b) Force Majeure. A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. Any Party

claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgement of the affected Party.

11.14 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the affected Parties and affected market participants, if any. Each affected Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The affected Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days, unless: (a) a Party or market participant identifies exigent circumstances reasonably requiring expedited resolution of the dispute by FERC or a court or agency with jurisdiction over the dispute; or (b) the provisions of this Agreement otherwise provide a Party the right to submit a dispute directly to FERC for resolution. Any other dispute that is not resolved through good-faith negotiations may, by any Party or any market participant, be submitted for resolution by FERC or a court or agency with jurisdiction over the dispute upon the conclusion of such negotiations. Any Party or market participant may request that any dispute submitted to FERC for resolution be subject to FERC settlement procedures. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of all affected Parties and all affected market participants to participate in such an alternative dispute resolution process.

11.15 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate; provided that nothing in this Section 11.15 shall limit a Party's right to appeal conditions to regulatory approval in accordance with Section 11.20(d).

11.16 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.17 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and each PTO arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The

Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against any other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.18 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.19 **Conditions Precedent.** Notwithstanding anything to the contrary in this Agreement, this Agreement shall not be effective with respect to any Party unless all of the conditions precedent set forth in this Section 11.19 shall have been satisfied or waived.

(a) Required Regulatory Approvals. All final required regulatory approvals shall have been obtained and be in full force and effect and shall not be subject to the satisfaction of any condition or conditions that, if accepted, would: (i) in the case of a PTO, in the reasonable judgment of such PTO, in the aggregate have a material adverse effect on the value of the PTO's Transmission Facilities, its expected level of transmission revenues, or its electric utility business, revenues, or financial condition, unless such PTO waives said condition, provided however, that with respect to any required regulatory approval obtained from a Governmental Authority of a State, the condition set forth in this clause shall apply only if such PTO operates its Transmission Business within such State; and (ii) in the case of the ISO, in its reasonable judgment, have a material adverse effect on the ISO's ability to perform its obligations under this or any other agreement to which it is subject, unless the ISO waives such condition.

(b) Board Consent. The board of directors of each Party, in its sole discretion, shall have authorized and approved such Party's executing, delivering and performing this Agreement.

(c) Additional Conditions Precedent. Additional conditions precedent are listed on Schedule 11.19(c).

(d) PTOs That Own Facilities Financed by Local Furnishing Bonds or Other Tax-Exempt Debt. As indicated in Section 3.13, each PTO that owns Transmission Facilities financed through Local Furnishing Bond(s) or other Tax-Exempt Debt shall have adequate assurance, in the opinion of each such PTO, that execution and performance of its obligations

under this Agreement will not jeopardize the tax-exempt status of their respective Tax-Exempt Debt or the ability of such PTOs to secure future tax-exempt financing.

(e) Right to Appeal Conditions to Regulatory Approval. In the event that a Governmental Authority conditions its regulatory approval of this Agreement on acceptance of a contractual provision, contractual modification, or any other condition or ruling related to formation of the New England RTO that is not acceptable to any Party, such Party shall have the option of agreeing to permit this Agreement to become effective with the condition or ruling to which it objects and appeal the propriety of the condition or ruling to courts of competent jurisdiction; provided that, in the event a Final Order requires a vacation or modification of such objectionable condition or ruling, this Agreement shall thereupon be modified consistent with that Final Order; provided, however, that other Parties may exercise their rights to withdraw from or terminate this Agreement pursuant to Section 10.01(b) or Section 10.01(d), as applicable.

11.20 **Preserved Rights.** No Party, by executing this Agreement, shall waive any rights to seek rehearing of a Commission order or to appeal a Commission order, including Commission orders concerning the terms and conditions of the NEPOOL tariff and market rules in effect prior to the Operations Date to the extent such terms and conditions have been incorporated into the ISO Tariff. The Parties expressly reserve the rights to pursue all pending requests for rehearing or appeals of such orders, and to file pleadings relating to such requests for rehearing or appeals, to the same extent as if the NEPOOL tariff were still in effect. Changes to the ISO Tariff shall be made to the extent necessary to comply with the results of a Commission rehearing order or judicial appeal concerning the terms and conditions of the NEPOOL tariff and market rules in effect prior to the Operations Date to the extent such terms and conditions have been incorporated into the ISO Tariff. The foregoing sentence shall not be deemed to prevent a Party from expressing its views to the Commission or a court regarding the foregoing compliance filing.

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each party as of the date first above written.

_____ Signature	_____ Party
_____ Title of Signatory	

Exhibit 10.5.6

EXECUTION FORM

SIXTH SUPPLEMENTAL INDENTURE

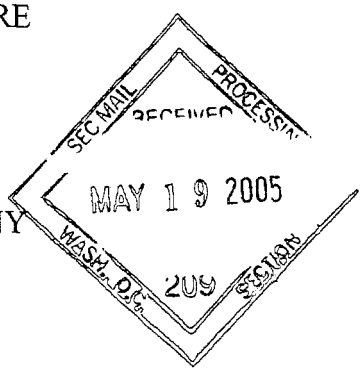
from

YANKEE GAS SERVICES COMPANY

to

THE BANK OF NEW YORK

TRUSTEE



Dated as of January 1, 2004

Supplemental to Indenture of Mortgage
and Deed of Trust from
Yankee Gas Services Company to
The Bank of New York (successor as trustee to
Fleet National Bank, formerly known as
The Connecticut National Bank), Trustee,
dated as of July 1, 1989

TO HAVE AND TO HOLD all said property, rights, privileges and franchises of every kind and description, real, personal or mixed, hereby and hereafter (by supplemental indenture or otherwise) granted, bargained, sold, aliened, remised, released, conveyed, assigned, transferred, mortgaged, hypothecated, pledged, set over or confirmed as aforesaid, or intended, agreed or covenanted so to be, together with all the appurtenances thereto appertaining (said properties, rights, privileges and franchises, including any cash and securities hereafter deposited or required to be deposited with the Trustee (other than any such cash which is specifically stated herein not to be deemed part of the Trust Estate), being herein collectively called "Trust Estate") unto the Trustee and its successors and assigns forever.

SUBJECT, HOWEVER, to Permitted Encumbrances (as defined in Section 1.01 of the Original Indenture).

BUT IN TRUST, NEVERTHELESS, for the proportionate and equal benefit and security of the Holders from time to time of all the Outstanding Secured Bonds without any preference or priority of any such Bond over any other such Bond.

UPON CONDITION that, until the happening of an Event of Default (as defined in Section 1.01 of the Original Indenture) and subject to the provisions of Article Six of the Original Indenture, the Company shall be permitted to possess and use the Trust Estate, except cash, securities and other personal property deposited and pledged, or required to be deposited and pledged, with the Trustee, and to receive and use the rents, issues, profits, revenues and other income of the Trust Estate.

AND IT IS HEREBY DECLARED that in order to set forth the terms and provisions of the new series of Bonds and in consideration of the premises and of the purchase and acceptance of such Bonds by the holders thereof, and in consideration of the sum of One Dollar ($1.00) to it duly paid by the Trustee, and of other good and valuable consideration, the receipt whereof is hereby acknowledged, and for the purpose of securing the faithful performance and observance of all the covenants and conditions of the Indenture, the Company hereby covenants and agrees with the Trustee and provides as follows:

ARTICLE I

DEFINITIONS AND RULES OF CONSTRUCTION

Section 1.01. Terms from the Original Indenture. All defined terms used in this Sixth Supplemental Indenture and not otherwise defined herein shall have the respective meanings ascribed to them in the Original Indenture.

Section 1.02. References are to Sixth Supplemental Indenture. Unless the context otherwise requires, all references herein to *"Articles," "Sections"* and other subdivisions are to the designated Articles, Sections and other subdivisions of this Sixth Supplemental Indenture, and the words *"herein," "hereof," "hereby," "hereunder"* and words of similar import refer to this Sixth Supplemental Indenture as a whole and not to any particular Article, Section or other subdivision hereof or to the Original Indenture.

ARTICLE II

specified in such notice, together with accrued interest thereon, and the premium, if any, payable with respect thereto shall become due and payable on the redemption date specified in such notice. Two business days prior to the redemption date specified in such notice of optional redemption, the Company shall provide the Trustee and each Holder of a Bond written notice of whether or not any premium is payable in connection with such redemption, the premium, if any, calculated as of the second business day prior to the redemption date, and a reasonably detailed computation of the Make-Whole Amount. The Trustee shall be under no duty to inquire into, may conclusively presume the correctness of, and shall be fully protected in acting upon the Company's calculation of any Make-Whole Amount.

For purposes of this Section 2.03, the term "Make-Whole Amount" shall mean in connection with any optional redemption of the Series G Bonds the excess, if any, of (a) the aggregate present value as of the date of such redemption of each dollar of principal amount of Series G Bonds being redeemed and the amount of interest (exclusive of interest accrued to the date of redemption) that would have been payable in respect of such dollar if such redemption had not been made, determined by discounting such amounts at the Reinvestment Rate from the respective dates on which they would have been payable, over (b) 100% of the principal amount of the outstanding Series G Bonds being redeemed.

The "Reinvestment Rate" means (1) the sum of .50% plus the yield reported on page "USD" of the Bloomberg Treasury/Money Market Monitor Screen (or, if not available, any other nationally recognized trading screen reporting on-line intraday trading in United States government securities) at 12:00 noon (New York time) on such date for United States government securities having a maturity rounded to the nearest month corresponding to the remaining Weighted Average Life to Maturity of the principal being redeemed, prepaid or paid or (2) in the event that no such nationally recognized trading screen reporting on-line intraday trading in United States government Securities is available, Reinvestment Rate means .50 plus the arithmetic mean of the yields under the respective headings "This Week" and "Last Week" published in the Statistical Release under the caption "Treasury Constant Maturities" for the maturity (rounded to the nearest month) corresponding to the Weighted Average Life to Maturity of the principal being redeemed. If no maturity exactly corresponds to such Weighted Average Life to Maturity, yields for the two published maturities most closely corresponding to such Weighted Average Life to Maturity shall be calculated pursuant to the immediately preceding sentence, and the Reinvestment Rate shall be interpolated or extrapolated from such yields on a straight-line basis, rounding in each of such relevant periods to the nearest month. For purposes of calculating the Reinvestment Rate, the most recent Statistical Release published prior to the date of determination of the Make-Whole Amount shall be used.

For purposes of this Section 2.03, "Weighted Average Life to Maturity" of the principal amount of the Series G Bonds being redeemed shall mean, as of the time of any determination thereof, the number of years obtained by dividing the then Remaining Dollar-Years of such principal by the aggregate amount of such principal. The term "Remaining Dollar-Years" of such principal shall mean the amount obtained by multiplying the amount of principal that would have become due at the Stated Maturity of the Series G Bonds if such redemption had not been made by the number of years (calculated to the nearest one-twelfth) which will elapse between the date of determination and the Stated Maturity of the Series G Bonds.

As used in this Section 2.03, "Statistical Release" shall mean the then most recently published statistical release designated "H.15(519)" or any successor publication which is published weekly by the Federal Reserve System and which establishes yields on actively traded United States government securities adjusted to constant maturities or, if such statistical release is not published at the time of any determination hereunder, then such other reasonably comparable index which shall be designated by the holders of 66-2/3% in aggregate principal amount of the outstanding Series G Bonds.

The principal amount, if any, of the Series G Bonds to be redeemed pursuant to this Section 2.03 shall be selected on a pro rata basis from all Series G Bonds Outstanding on the Redemption Date.

The Series G Bonds shall not be redeemable at the option of the Company prior to their Stated Maturity other than as provided in this Section 2.03.

All Series G Bonds issued upon transfer or exchange thereof shall bear such legend unless the Company shall have delivered to the Trustee an Opinion of Counsel which states that the Series G Bonds may be issued without such legend. All Series G Bonds issued upon transfer or exchange of a Series G Bond or Bonds which do not bear such legend shall be issued without such legend. The Company may from time to time modify the foregoing restrictions on resale and other transfers, without the consent of but upon notice to the Holders, in order to reflect any amendment to Rule 144A under the Securities Act of 1933 or change in the interpretation thereof or practices thereunder.

Section 2.08. Authentication and Delivery. Upon the execution of this Sixth Supplemental Indenture, the Series G Bonds shall be executed by the Company and delivered to the Trustee for authentication, and thereupon the same shall be authenticated and delivered by the Trustee pursuant to and upon Company Request.

Section 2.09. Default. Pursuant to the Original Indenture (and notwithstanding any provision of Section 9.22 thereof to the contrary), for purposes of determining whether an Event of Default exists with respect to the Series G Bonds, any default in payment (whether due as a scheduled installment of principal or interest, or at original maturity or earlier redemption or acceleration, or otherwise) with respect to Bonds of any other series which constitutes an Event of Default with respect to the Bonds of such series shall also constitute an Event of Default with respect to the Series G Bonds.

ARTICLE III

MISCELLANEOUS PROVISIONS

Section 3.01. Effectiveness and Ratification of Indenture. The provisions of this Sixth Supplemental Indenture shall be effective from and after the execution hereof; and the Indenture, as hereby supplemented, shall remain in full force and effect.

Section 3.02. Titles. The titles of the several Articles and Sections of this Sixth Supplemental Indenture shall not be deemed to be any part thereof, are inserted for convenience only and shall not affect any interpretation hereof.

Section 3.03. Acceptance of Trust; Not Responsible for Recitals; Etc. The Trustee hereby accepts the trusts herein declared, provided, created or supplemented and agrees to perform the same upon the terms and conditions herein and in the Original Indenture, as heretofore supplemented, set forth and upon the following terms and conditions:

> The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Sixth Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made by the Company solely. In general, each and every term and condition contained in Article Ten of the Original Indenture shall apply to and form part of this Sixth Supplemental Indenture with the same force and effect as if the same were herein set forth in full with such omissions, variations and insertions, if any, as may be appropriate to make the same conform to the provisions of this Sixth Supplemental Indenture.

Section 3.04. Successors and Assigns. All covenants, provisions, stipulations and agreements in this Sixth Supplemental Indenture contained are and shall be for the sole and exclusive benefit of the parties hereto, their successors and assigns, and (subject to the provisions of the Bond Purchase

IN WITNESS WHEREOF, the parties hereto have caused this Sixth Supplemental Indenture to be duly executed, sealed and attested as of the day and year first above written.

YANKEE GAS SERVICES COMPANY

By /s/ Randy A. Shoop
Name: Randy A. Shoop
Title: Assistant Treasurer

Attest:

/s/ O. Kay Comendul
Name: O. Kay Comendul
Title: Assistant Secretary

Executed, sealed and delivered by
YANKEE GAS SERVICES COMPANY
in the presence of:

/s/ Jane Seidl
Jane Seidl

/s/ Sharon Walter
Sharon Walter

THE BANK OF NEW YORK, as Trustee

By /s/ Geovanni Barris
Name: Geovanni Barris
Title: Vice President

Attest:

/s/ Marie Trimboli

Executed, sealed and delivered by
THE BANK OF NEW YORK, as Trustee,
in the presence of:

/s/ Ming Ryan
/s/ Robert A. Massimillo

SCHEDULE A

ALL THE PROPERTY, RIGHT, PRIVILEGES AND FRANCHISES AS SET FORTH IN THE FOLLOWING DESCRIPTIONS.

Yankee Gas Services Company
First Mortgage Bonds,
4.80% Series G, Due 2014

CUSIP Number 98478* AL 1

No. G -

Principal Amount: $

Stated Maturity of Principal: January 1, 2014

Applicable Rate: 4.80%

Interest Payment Dates: July 1 and January 1, commencing July 1, 2004
and at the Stated Maturity of the principal

Yankee Gas Services Company, a specially chartered Connecticut corporation (hereinafter called the "Company", which term includes any successor corporation under the Indenture hereinafter referred to), for value received, hereby promises to pay to [_____], or registered assigns, at the Stated Maturity set forth above, the Principal Amount set forth above (or so much thereof as shall not have been paid upon prior redemption) and to pay interest (computed on the basis of a 360-day year of twelve 30-day months) thereon from the date of issuance hereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for, on each Interest Payment Date set forth above in each year at the Applicable Rate set forth above. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in said Indenture, be paid to the Person in whose name this Bond (or one or more Predecessor Bonds, as defined in said Indenture) is registered at the close of business on the Regular Record Date for such interest, which shall be the 15th day (whether or not a business day) of the calendar month next preceding such Interest Payment Date. Any such interest not so punctually paid or duly provided for shall be paid to the Person in whose name this Bond is registered on the business day immediately preceding the date of such payment. If all or any portion of the principal of, or the premium (if any) or interest on, this Bond shall not be paid when due, the amount not so paid shall bear interest at the lesser of (x) the highest rate allowed by applicable law or (y) the greater of (i) the Prime Rate (as defined in the Bond Purchase Agreements) or (ii) 5.80% (the Applicable Rate plus 1% per annum).

The principal and the Redemption Price of, and the interest on, this Bond shall be payable at the principal corporate trust office of The Bank of New York, in New York, New York. All such payments shall be made in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts.

This Bond is one of a duly authorized issue of Bonds of the Company designated as its "First Mortgage Bonds" (herein called the "Bonds"), issued and to be issued in one or more series under, and all equally and ratably secured by, an Indenture of Mortgage and Deed of Trust, dated as of July 1, 1989, (herein, together with any indenture or instruments supplemental thereto, including the First Supplemental Indenture dated as of April 1, 1992, the Second Supplemental Indenture dated as of December 1, 1992, the Third Supplemental Indenture dated as of June 1, 1995, the Fourth Supplemental Indenture dated as of April 1, 1997, the Fifth Supplemental Indenture dated as of January 1, 1999, and the Sixth

the modification of the rights and obligations of the Company and the rights of the Holders of the Bonds under the Indenture at any time by the Company with the consent of the Holders of a majority in aggregate principal amount of the Bonds of all series at the time Outstanding affected by such modification. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of Bonds at the time Outstanding on behalf of the Holders of all the Bonds, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver agreed to as set forth above by the Holder of this Bond shall be conclusive and binding upon such Holder and upon all future Holders of this Bond and of any Bond issued upon the transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Bond.

No reference herein to the Indenture and no provision of this Bond or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of (and premium, if any) and interest on this Bond at the times, places and rates, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, this Bond is transferable on the Bond Register of the Company, upon surrender of this Bond for transfer at the office or agency of the Company in New York, New York, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Bond Registrar, duly executed by the Registered Holder hereof or by his attorney duly authorized in writing, and thereupon one or more new Bonds of the same series, or authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

All Bonds of this series shall be fully interchangeable, and, upon surrender at the office or agency of the Company in a Place of Payment therefor, shall be exchangeable for other Bonds of this series of a different authorized denomination or denominations, as requested by the Holder surrendering the same.

No service charge shall be made for any transfer or exchange hereinbefore referred to, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

The Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Bond is registered as the owner hereof for the purpose of receiving payment as herein provided and for all other purposes, whether or not this Bond is overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

Unless the certificate of authentication hereon has been executed by the Trustee or Authenticating Agent by manual signature, this Bond shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

[THIS SPACE INTENTIONALLY LEFT BLANK]

[Signature page for Yankee Gas Services Company, First Mortgage Bond, 4.80% Series G, Due 2014]

IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed under its corporate seal.

Dated: _____ YANKEE GAS SERVICES COMPANY

By_____ Name:
Title:

Attest:

_____

This is one of the Bonds of the series designated therein referred to in the within-mentioned Indenture.

THE BANK OF NEW YORK, as Trustee

By_____
Authorized Officer

50994 v.09/12680-2029/Series G

Exhibit 10.5.7

SEVENTH SUPPLEMENTAL INDENTURE
from
YANKEE GAS SERVICES COMPANY
to
THE BANK OF NEW YORK
TRUSTEE

Dated as of November 1, 2004

Supplemental to Indenture of Mortgage
and Deed of Trust from
Yankee Gas Services Company to
The Bank of New York (successor as trustee to
Fleet National Bank, formerly known as
The Connecticut National Bank), Trustee,
dated as of July 1, 1989

SEVENTH SUPPLEMENTAL INDENTURE

SEVENTH SUPPLEMENTAL INDENTURE, dated as of November 1, 2004 between YANKEE GAS SERVICES COMPANY, a specially chartered Connecticut corporation (herein called the *"Company H),* and THE BANK OF NEW YORK, a New York banking corporation, successor to Fleet National Bank (formerly known as The Connecticut National Bank), as Trustee (the *"Trustee')* under the Indenture of Mortgage and Deed of Trust, dated as of July 1, 1989, executed and delivered by the Company (herein called the *"Original Indenture";* the Original Indenture and any and all indentures and instruments supplemental thereto, including, without limitation, this Seventh Supplemental Indenture, being herein called the *"Indenture");*

WHEREAS, pursuant to Sections 13.01(C), 13.01(G), 3.03 and Article Five of the Original Indenture, the Company desires to provide for the issuance under the Indenture of a new series of Bonds, which Bonds will be secured by and entitled to the benefits of the Indenture, and to add to its covenants and agreements contained in the Original Indenture certain other covenants and agreements; and

WHEREAS, all acts and things necessary to make this Seventh Supplemental Indenture a valid, binding and legal instrument have been performed, and the issuance of the new series of Bonds, subject to the terms of the Original Indenture, has been duly authorized by the Board of Directors of the Company and approved by the Connecticut Department of Public Utility Control, and the Company has requested and hereby requests the Trustee to enter into and join the Company in the execution and delivery of this Seventh Supplemental Indenture;

NOW, THEREFORE, THIS SEVENTH SUPPLEMENTAL INDENTURE WITNESSETH, that, to secure the payment of the principal of (and premium, if any) and interest on the Outstanding Secured Bonds, including the new series of Bonds hereunder issued, and the performance of the covenants therein and herein contained and to declare the terms and conditions on which all such Outstanding Secured Bonds are secured, and in consideration of the premises and of the purchase of the Bonds by the Holders thereof, the Company by these presents does grant, bargain, sell, alien, remise, release, convey, assign, transfer, mortgage, hypothecate, pledge, set over and. confirm to the Trustee, all property, rights, privileges and franchises of the Company of every kind and description, real, personal or mixed, tangible and intangible, whether now owned or hereafter acquired by the Company, wherever located, and grants a security interest therein for the purposes herein expressed, except any Excepted Property which is expressly excepted from the lien hereof in the Original Indenture, and including, without limitation, all and singular the following:

> All property, rights, privileges and franchises particularly described in the Original Indenture, and any and all indentures and instruments supplemental thereto, including, without limitation, the
>
> First Supplemental Indenture dated as of April 1, 1992, the Second Supplemental Indenture dated as of December 1, 1992, the Third Supplemental Indenture dated as of June 1, 1995, the Fourth Supplemental Indenture dated as of April 1, 1997, the Fifth Supplemental Indenture dated as of January 1, 1999, the Sixth Supplemental Indenture dated as of January 1, 2004, and in addition, all the property, rights, privileges and franchises particularly described in Schedule A annexed to this Seventh Supplemental

Indenture, which are hereby made a part of, and deemed to be described herein, as fully as if set forth herein at length.

TO HAVE AND TO HOLD all said property, rights, privileges and franchises of every kind and description, real, personal or mixed, hereby and hereafter (by supplemental indenture or otherwise) granted, bargained, sold, aliened, remised, released, conveyed, assigned, transferred, mortgaged, hypothecated, pledged, set over or confirmed as aforesaid, or intended, agreed or covenanted so to be, together with all the appurtenances thereto appertaining (said properties, rights, privileges and franchises, including any cash and securities hereafter deposited or required to be deposited with the Trustee (other than any such cash which is specifically stated herein not to be deemed part of the Trust Estate), being herein collectively called "Trust Estate") unto the Trustee and its successors and assigns forever.

SUBJECT, HOWEVER, to Permitted Encumbrances (as defined in Section 1.01 of the Original Indenture).

BUT IN TRUST, NEVERTHELESS, for the proportionate and equal benefit and security of the Holders from time to time of all the Outstanding Secured Bonds without any preference or priority of any such Bond over any other such Bond.

UPON CONDITION that, until the happening of an Event of Default (as defined in Section 1.01 of the Original Indenture) and subject to the provisions of Article Six of the Original Indenture, the Company shall be permitted to possess and use the Trust Estate, except cash, securities and other personal property deposited and pledged, or required to be deposited and pledged, with the Trustee, and to receive and use the rents, issues, profits, revenues and other income of the Trust Estate.

AND IT IS HEREBY DECLARED that in order to set forth the terms and provisions of the new series of Bonds and in consideration of the premises and of the purchase and acceptance of such Bonds by the holders thereof, and in consideration of the sum of One Dollar ($1.00) to it duly paid by the Trustee, and of other good and valuable consideration, the receipt whereof is hereby acknowledged, and for the purpose of securing the faithful performance and observance of all the covenants and conditions of the Indenture, the Company hereby covenants and agrees with the Trustee and provides as follows:

ARTICLE I
DEFINITIONS AND RULES OF CONSTRUCTION

Section 1.01 Terms from the Original Indenture. All defined terms used in this Seventh Supplemental Indenture and not otherwise defined herein shall have the respective meanings ascribed to them in the Original Indenture.

Section 1.02. References are to Seventh Supplemental Indenture. Unless the context otherwise requires, all references herein to *"Articles, " "Sections"* and other subdivisions are to the designated Articles, Sections and other subdivisions of this Seventh Supplemental Indenture, and the words *"herein, " "hereof, " "hereby, " "hereunder"* and words of similar import refer to this Seventh Supplemental Indenture as a whole and not to any particular Article, Section or other subdivision hereof or to the Original Indenture.

ARTICLE II
SERIES H BONDS

Section 2.01 Specific Title, Terms and Forms. There is hereby created and shall be outstanding under and secured by the Indenture a series of Bonds entitled "First Mortgage Bonds, 5.26% Series H, Due 2019" (herein called the *"Series H Bonds"),* limited in aggregate principal, amount at any one time outstanding to Fifty Million Dollars ($50,000,000). The form of the Series H Bonds shall be substantially as set forth in Exhibit A hereto with such insertions, omissions, substitutions and variations as may be determined by the officers executing the same as evidenced by their execution thereof.

The Series H Bonds shall be issued as fully registered Bonds in denominations of $1,000,000 or any amount in excess thereof which is an integral multiple of $250,000 (except as may be necessary to reflect any principal amount not evenly divisible by $250,000 remaining after any partial redemption), or in such other denominations as the Trustee may approve. The Series H Bonds shall be numbered H-1 and consecutively upwards, or in any other manner deemed appropriate by the Trustee. The Series H Bonds shall mature on November 1, 2019 and shall bear interest from the date of issuance thereof (or from the most recent Interest Payment Date to which interest has been paid or duly provided for) at the rate of five and twenty-six hundredths percent (5.26%) per annum (computed on the basis of a 360-day year of twelve 30-day months).

Interest Payment Dates for the Series H Bonds shall be (i) May 1 and November 1 of each year, commencing May 1, 2005, and (ii) at the Stated Maturity of the principal.

Notwithstanding the otherwise applicable provisions of the Indenture, the principal and the Redemption Price of, and interest on, the Series H Bonds shall be payable by Federal funds bank wire transfer of immediately available funds so long as required by Section 5.1 of the Bond Purchase Agreements, each dated November 15, 2004, between the Company and the initial purchasers of the Series H Bonds (the "Bond Purchase Agreements") or, in the event Section 5.1

shall no longer be applicable, at the office or agency of the Company in New York, New York, in such coin or currency of the United States of America as at the time of payment is legal tender for public or private debts.

The Regular Record Date referred to in Section 3.09 of the Original Indenture for the payment of the interest on the Series H Bonds payable, and punctually paid or duly provided for, on any Interest Payment Date shall be the 15th day (whether or not a business day) of the calendar month next preceding such Interest Payment Date.

Section 2.02 No Sinking Fund; No Mandatory Scheduled Redemption Prior to Final Maturity. The Series H Bonds shall not be subject to any sinking fund or mandatory scheduled redemption prior to final maturity.

Section 2.03 Optional Redemption. The Series H Bonds shall be redeemable at the option of the Company in whole at any time or in part from time to time prior to their Stated Maturity, at a redemption price equal to the principal amount of the Series H Bonds being prepaid plus accrued interest thereon to the date of such redemption together with a premium equal to the then applicable Make-Whole Amount.

The Company will give notice of any optional redemption of the Series H Bonds pursuant to this Section 2.03 to each Holder thereof not less than 30 days nor more than 60 days before the date fixed for such optional redemption, specifying (a) such date, (b) the principal amount of the Holder's Bond to be redeemed on such date, (c) that a premium may be payable, (d) the estimated premium, calculated as of the day such notice is given, and (e) the accrued interest applicable to the redemption. Such notice of redemption shall also certify all facts, if any, which are conditions precedent to any such redemption. Notice of redemption having been so given, the aggregate principal amount of the Series H Bonds specified in such notice, together with accrued interest thereon, and the premium, if any, payable with respect thereto shall become due and payable on the redemption date specified in such notice. Two business days prior to the redemption date specified in such notice of optional redemption, the Company shall provide the Trustee and each Holder of a Bond written notice of whether or not any premium is. payable in connection with such redemption, the premium, if any, calculated as of the second business day prior to the redemption date, and a reasonably detailed computation of the Make-Whole Amount. The Trustee shall be under no duty to inquire into, may conclusively presume the correctness of, and shall be fully protected in acting upon the Company's calculation of any Make-Whole Amount.

For purposes of this Section 2.03, the term "Make-Whole Amount" shall mean in connection with any optional redemption of the Series H Bonds the excess, if any, of (a) the aggregate present value as of the date of such redemption of each dollar of principal amount of Series H Bonds being redeemed and the amount of interest (exclusive of interest accrued to the date of redemption) that would have been payable in respect of such dollar if such redemption had not been made, determined by discounting such amounts at the Reinvestment Rate from the respective dates on which they would have been payable, over (b) 100% of the principal amount of the outstanding Series H Bonds being redeemed.

The "Reinvestment Rate" means (1) the sum of .50% plus the yield reported on page "USD" of the Bloomberg Treasury/Money Market Monitor Screen (or, if not available, any other nationally recognized trading screen reporting on-line intraday trading in United States

government securities) at 12:00 noon (New York time) on such date for United States government securities having a maturity rounded to the nearest month corresponding to the remaining Weighted Average Life to Maturity of the principal being redeemed, prepaid or paid or (2) in the event that no such nationally recognized trading screen reporting on-line intraday trading in United States government Securities is available, Reinvestment Rate means .50 plus the arithmetic mean of the yields under the respective headings "This Week" and "Last Week" published in the Statistical Release under the caption "Treasury Constant Maturities" for the maturity (rounded to the nearest month) corresponding to the Weighted Average Life to Maturity of the principal being redeemed. If no maturity exactly corresponds to such Weighted Average Life to Maturity, yields for the two published maturities most closely corresponding to such Weighted Average Life to Maturity shall be calculated pursuant to the immediately preceding sentence, and the Reinvestment Rate shall be interpolated or extrapolated from such yields on a straight-line basis, rounding in each of such relevant periods to the nearest month. For purposes of calculating the Reinvestment Rate, the most recent Statistical Release published prior to the date of determination of the Make-Whole Amount shall be used.

For purposes of this Section 2.03, "Weighted Average Life to Maturity" of the principal amount of the Series H Bonds being redeemed shall mean, as of the time of any determination thereof, the number of years obtained by dividing the then Remaining Dollar-Years of such principal by the aggregate amount of such principal. The term "Remaining Dollar-Years" of such principal shall mean the amount obtained by multiplying the amount of principal that would have become due at the Stated Maturity of the Series H Bonds if such redemption had not been made by the number of years (calculated to the nearest one-twelfth) which will elapse between the date of determination and the Stated Maturity of the Series H Bonds.

As used in this Section 2.03, "Statistical Release" shall mean the then most recently published statistical release designated "H.15(519)" or any successor publication which is published weekly by the Federal Reserve System and which establishes yields on actively traded United States government securities adjusted to constant maturities or, if such statistical release is not published at the time of any determination hereunder, then such other reasonably comparable index which shall be designated by the holders of 66 2/3 % in aggregate principal amount of the outstanding Series H Bonds.

The principal amount, if any, of the Series H Bonds to be redeemed pursuant to this Section 2.03 shall be selected on a pro rata basis from all Series H Bonds Outstanding on the Redemption Date.

The Series H Bonds shall not be redeemable at the option of the Company prior to their Stated Maturity other than as provided in this Section 2.03.

Section 2.04. Place of Payment. The principal and the Redemption price of, and the premium, if any, and the interest on, the Series H Bonds shall be payable at the principal corporate trust office of The Bank of New York, in New York, New York.

Section 2.05. Exchangeability. Subject to Section 3.07 of the Original Indenture, all Series H Bonds shall be fully interchangeable, and, upon surrender at the office or agency of *the Company in a Place of Payment therefor, shall be exchangeable for other Series H Bonds of a different authorized denomination or denominations, as requested by the Holder surrendering the

same. The Company will execute, and the Trustee shall authenticate and deliver, Series H Bonds whenever the same are required for any such exchange.

Section 2.06. Bond Purchase Agreements. Reference is made to Sections 5 and 7 of the Bond Purchase Agreements for certain provisions governing the rights and obligations of the Company, the Trustee and the Holders of the Series H Bonds. Such provisions are deemed to be incorporated in this Article II by reference as if set forth herein at length.

Section 2.07. Restrictions on Transfer. All Series H Bonds originally issued hereunder shall bear the following legend:

> THIS SECURITY HAS NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (THE "1933 ACT"). THE HOLDER HEREOF, BY PURCHASING THIS SECURITY, AGREES FOR THE BENEFIT OF YANKEE GAS SERVICES COMPANY (THE "COMPANY") AND PRIOR HOLDERS THAT THIS SECURITY MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) TO THE COMPANY (UPON REDEMPTION THEREOF OR OTHERWISE), (2) SO LONG AS THIS SECURITY IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A, TO A PERSON WHO THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER, WITHIN THE MEANING OF RULE 144A UNDER THE 1933 ACT, IN A TRANSACTION MEETING. THE REQUIREMENTS OF RULE 144A, (3) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH REGULATION S UNDER THE 1933 ACT, (4) PURSUANT TO AN EXEMPTION FROM REGISTRATION IN ACCORDANCE WITH RULE 144 (IF AVAILABLE) UNDER THE 1933 ACT, (5) IN RELIANCE ON ANOTHER EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT, SUBJECT TO THE RECEIPT BY THE COMPANY OF AN OPINION OF COUNSEL TO THE EFFECT THAT SUCH TRANSFER IS EXEMPT FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT OR (6) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE 1933 ACT, SUBJECT (IN THE CASE OF CLAUSES (2), (3), (4) AND (5)) TO THE RECEIPT BY THE COMPANY OF A CERTIFICATION OF THE TRANSFEROR (WHICH, IN THE CASE OF CLAUSE (4), MAY BE A COPY OF FORM 144 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION) TO THE EFFECT THAT SUCH TRANSFER IS IN COMPLIANCE WITH THE 1933 ACT, AND IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY JURISDICTION OF THE UNITED STATES. THE HOLDER OF THIS SECURITY WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SECURITY FROM IT OF THE RESALE RESTRICTIONS REFERRED TO HEREIN.

All Series H Bonds issued upon transfer or exchange thereof shall bear such legend unless the Company shall have delivered to the Trustee an Opinion of Counsel which states that the Series H Bonds may be issued without such legend. All Series H Bonds issued upon transfer or exchange of a Series H Bond or Bonds which do not bear such legend shall be issued without such legend. The Company may from time to time modify the foregoing restrictions on resale

and other transfers, without the consent of but upon notice to the Holders, in order to reflect any amendment to Rule 144A under the Securities Act of 1933 or change in the interpretation thereof or practices thereunder.

Section 2.08 Authentication and Delivery. Upon the execution of this Seventh Supplemental Indenture, the Series H Bonds shall be executed by the Company and delivered to the Trustee for authentication, and thereupon the same shall be authenticated and delivered by the Trustee pursuant to and upon Company Request.

Section 2.09. Default. Pursuant to the Original Indenture (and notwithstanding any provision of Section 9.22 thereof to the contrary), for purposes of determining whether an Event of Default exists with respect to the Series H Bonds, any default in payment (whether due as a scheduled installment of principal or interest, or at original maturity or earlier redemption or acceleration, or otherwise) with respect to Bonds of any other series which constitutes an Event of Default with respect to the Bonds of such series shall also constitute an Event of Default with respect to the Series H Bonds.

ARTICLE III
MISCELLANEOUS PROVISIONS

Section 3.01. Effectiveness and Ratification of Indenture. The provisions of this Seventh Supplemental Indenture shall be effective from and after the execution hereof; and the Indenture, as hereby supplemented, shall remain in full force and effect.

Section 3.02. Titles. The titles of the several Articles and Sections of this Seventh Supplemental Indenture shall not be deemed to be any part thereof, are inserted for convenience only and shall not affect any interpretation hereof.

Section 3.03. Acceptance of Trust; Not Responsible for Recitals; Etc. The Trustee hereby accepts the trusts herein declared, provided, created or supplemented and agrees to perform the same upon the terms and conditions herein and in the Original Indenture, as heretofore supplemented, set forth and upon the following terms and conditions:

The Trustee shall not be responsible in any manner whatsoever for or in respect of the validity or sufficiency of this Seventh Supplemental Indenture or for or in respect of the recitals contained herein, all of which recitals are made by the Company solely.. In general, each and every term and condition contained in Article Ten of the Original Indenture shall apply to and form part of this Seventh Supplemental Indenture with the same force and effect as if the same were herein set forth in full with such omissions, variations and insertions, if any, as may be appropriate to make the same conform to the provisions of this Seventh Supplemental Indenture.

Section 3.04. Successors and Assigns. All covenants, provisions, stipulations and agreements in this Seventh Supplemental Indenture contained are and shall be for the sole and exclusive benefit of the parties hereto, their successors and assigns, and (subject to the provisions of the Bond Purchase Agreements) of the Holders and registered owners from time to time of the Bonds issued and outstanding under and secured by the Indenture (except that the provisions of Article II hereof are and shall be for the sole and exclusive benefit of the Holders of the Series H Bonds).

Section 3.05. Counterparts. This Seventh Supplemental Indenture may be executed in any number of counterparts, each of which so executed shall be deemed to be an original, and all such counterparts shall together constitute but one and the same instrument.

Section 3.06. Governing Law. The laws of the State of Connecticut shall govern this Seventh Supplemental Indenture and the Series H Bonds, except to the extent that the validity or perfection of the lien of the Indenture, or remedies thereunder, are governed by the laws of a jurisdiction other than the State of Connecticut.

[THIS SPACE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have caused this Seventh Supplemental Indenture to be duly executed, sealed and attested as of the day and year first above written.

YANKEE GAS SERVICES COMPANY

By /s/ Randy A. Shoop
Name: Randy A. Shoop
Title: _Assistant Treasurer

Attest:

/s/ O. Kay Comendul
Name: O. K. Comendul
Title: Assistant Secretary

Executed, sealed and delivered by
YANKEE GAS SERVICES COMPANY
in the presence of:

/s/ Jane Seidl

/s/ Eileen R. Kearney

THE BANK OF NEW YORK, as Trustee

By /s/ _Geovanni Barris
Name: Geovanni Barris
Title: _Vice President

Attest:

/s/ Ming Ryan

Executed, sealed and delivered by

THE BANK OF NEW YORK, as Trustee,
in the presence of:

/s/ Michael Pitfick
/s/ Remo Reale

STATE OF CONNECTICUT)
) ss.: Berlin
COUNTY OF HARTFORD)

On this 8th day of November, 2004, before me, Lisa Barlow, the undersigned officer, personally appeared Randy A. Shoop and O. Kay Comendul, who acknowledged themselves to be the Assistant Treasurer and Assistant Secretary, respectively, of Yankee Gas Services Company, a Connecticut corporation, and that they, as such officers, being authorized so to do, executed the foregoing instrument for the purpose therein contained, by signing the name of the corporation by themselves as such officers, and as their free act and deed.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

/s/ Lisa Barlow
Notary Public
My commission expires: March 31, 2006

(SEAL)

STATE OF NEW YORK)
ss.:
COUNTY OF NEW YORK)

On this 8th day of November, 2004, before me, William Cassels, the undersigned officer, personally appeared Geovanni Barris and Ming Ryan, who acknowledged themselves to be and Vice President and Vice President, respectively, of The Bank of New York, a New York banking corporation, and that they, as such officers, being authorized so to do, executed the foregoing instrument for the purposes therein contained, by signing the name of the association by themselves as such officers, and as their free act and deed.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

/s/ William Cassels
Notary Public State of New York
No. 01CA5027729
Qualified in Bronx County
Commission Expires May 18, 2006

SCHEDULE A

ALL THE PROPERTY, RIGHT, PRIVILEGES AND FRANCHISES AS SET FORTH IN THE FOLLOWING DESCRIPTIONS.

Yankee Gas Fee Acquisitions (1999-2003)

Town Name	Grantor	DEED Date	Volume	Page
Berlin	D. Urlage	8/14/02 1	477	567

The following described property located in the Town of Berlin,. County of Hartford, State of Connecticut shown and designated as Lot No. 15-P on a certain map or plan entitled:

"RESUBDIVISION PLAN HERITAGE ESTATES, To Be Developed By JCT DEVELOPMENT CORP., Property Known As Lot 15-Q & Portion Lot 15-K HERITAGE DRIVE BERLIN, CONNECTICUT" Scale 1"= 40' Date DEC. 28, 1988 Sheet 1 of 4, which map is on file in the Berlin Town Clerk's Office as Map No. 23893.

Said premises are conveyed subject to building, building line and zoning restrictions of the Town of Berlin and to the second installment of taxes on the List of October 1,. 2001, which are not yet due and payable.

Said premises are also subject to:

1. Notes and legends on Map No. 23893 entitled "Resubdivision Plan Heritage Estates to Be Developed by JCT Development Corp. Property Known As Lot 15-Q & Portion or Lot 15-K Heritage Drive Berlin, Connecticut Scale 1"=40' Date Dec. 29, 1988 prepared by MBA Engineering" which map is on file in the office of the Berlin Town Clerk;

2. Declaration of Restrictions and Covenants by Helen Tricka, dated and recorded November 1, 1990 in Volume 209, Page 698;

3. Notice of the Town of Berlin Health Department dated August 8, 1997 and recorded September 8, 1997 in Volume 396, Page 907;

4. Electric Distribution Easement, Helen Tricka to The Connecticut Light & Power Company dated January 27, 1989 and recorded March 22, 1989 in Volume 291, Page 545. (Maps 2341 & 2342);

5. Right of Way Easement, Carl Tricka and Helen Tricka to Algonquin Gas Transmission Company dated October 24, 1951 and recorded November 8, 1951 in Volume 103, Page 164.

NOTE: This is a corrected copy of the sheet entitled "Yankee Gas Fee Acquisitions (1999-2003)" included in Schedule A to the Sixth Supplemental Indenture.

Yankee Gas Non-Distribution Easements (1999-2003)

Town Name	Grantor	Date Esmt Recorded	Volume	Page
Southington	A. Orciso	9/18/02	855	802
Southington	J. Pardo	7/19/02	847	442
Southington	D. Nichols	9/11/02	854	830
Southington	Cath Cem Assoc.	9/23/02	856	224
Southington	Town of	8/16/02	851	74
Southington	YMCA	9/20/02	856	24
Southington	D. Myjack	8/29/02	852	1015
Kensington	L. DeVivo	8/23/02	478	158
Kensington	R. Rampone	9/11/02	479	363
Kensington	K. McHale	9/11/02	479	359
Kensington	T. Hrubiec	9/19/02	479	770
Kensington	B. Malloy	9/5/02	478	1001
Kensington	R. Burkhart	9/5/02	478	998
Kensington	J. Inturri	8/21/02	478	76
Kensington	D. Roche	8/7/02	477	139
Kensington	J. Roche	8/21/02	478	79
Kensington	R. Solek	8/14/02	477	484
Kensington	J. Russo	9/17/02	479	767
Kensington	R. DeMaria	8/8/02	477	148
Kensington	H. Tricka (Est)	9/3/02	478	915
Kensington	H. Tricka (Est)	9/3/02	478	920
Kensington	City of Meriden	8/15/02	477	619
Kensington	D. Cross	8/13/02	477	371
Kensington	St of Conn	10/17/02	482	405
Kensington	S. Hushak	8/15/02	477	664

NOTE: This is a corrected copy of the sheet entitled "Yankee Gas Non-Distribution Easements (1999-2003)" included in Schedule A to the Sixth Supplemental Indenture.

Yankee Distribution Easements

(1/1/2004 - 10/31/2004)

Town	Grantor	Instrument Date	Volume	Date
SOUTH WINDSOR	EVERGREEN WALK LLC	06/30/04	1636	274
SOUTH WINDSOR	EVERGREEN WALK, LLC	05/27/04	1617	273
CHESHIRE	DIVERSIFIED COOK HILL, LLC	09/09/04	1898	2
ENFIELD	DENIS J. LESSARD ET AL	08/22/04	1913	135
WINDSOR LOCKS	NORTH GROUP DEVELOPMENT, LLC ET AL	07/29/04	325	647
EAST WINDSOR	MYERS NURSERY, INC.	03/09/04	268	497
NORWALK	RMS-ISAAC STREET, LLC	03/30/04	5383	223
MIDDLETOWN	MEDICAL DEVELOPMENT ASSOCIATES, LLC	01/30/04	1430	990
PUTNAM	HERITAGE PINE CONDOMINIUM ASSOCIATION, INC	01/10/04	464	261
PLAINFIELD	NAPLES HOLDING CORP.	04/01/03	309	1231
SUFFIELD	KRYSTAL WOODS DEVELOPERS, LLC	09/02/04	373	1132
ELLINGTON	ELLINGTON COMMONS ASSOCIATES	08/12/04	339	903

YANKEE GAS LEASEHOLD INTEREST -- ANSONIA

Lease from Tice Brothers. LLC to Yankee Gas Services Company dated as of October 1, 2001. Notice of Lease recorded in Volume 352, Page 1042 of the Ansonia Land Records.

Description of leased premises:

All that certain piece or parcel of land together with the building and improvements thereon containing 22,393 square feet, known as 488 Main Street and located at the corner of Chestnut and Main Streets, Ansonia, CT, which parcel is more particularly shown on a certain unrecorded map entitled "SITE PLAN 88 Main Street & I Chestnut Street Ansonia, Connecticut prepared for Ansonia Tice Properties, LLC date: April 10, 2001 scale l "=20" "prepared by Louis Associates, 260 Main Street, Monroe, CT.

Said premises are subject to:

I. Such matters and notes as are shown on a map entitled "LOT LINE REVISION PLAN OF PROPERTY LOCATED AT 420-488 MAIN STREET AND I CHESTNUT STREET ANSONIA CONNECTICUT PREPARED FOR TICE BROTHERS, LLC DATE OCT. 18, 2001 [revised through 11-16-01) SCALE 1 "=30'," prepared by Lewis Associates Land Surveying and Civil Engineering, on file as Map 14/49 of the Ansonia Land Records.

2. Encumbrances listed in the Warranty Deed from Myron E. Yudkin to Tice Brothers, LLC dated April 20. 2001 and recorded in Volume 344, Page 134 of the Ansonia Land Records.

3. Unrecorded License Easement Agreement with the City of Ansonia.

4. Possible effect of oil storage tanks are shown on a map entitled "MAP PREPARED FOR MYRON YUDKIN ANSONIA, CONNECTICUT SCALE 1"=40' NOVEMBER 5, 1990 REV TO JANUARY 16,1991."

5. Open-End Mortgage Deed and Security Agreements in the amount of $750,000 and $250,000 from Ansonia Tice Properties, LLC and Tice Brothers, LLC to Naugatuck Valley Savings and Loan Association, Inc. dated December 5, 2001 and recorded in, respectively, Volume 354, Page 712 and Volume 354, Page 738 of the Ansonia Land Records. (Note: Yankee Gas Services Company received a Nondisturbance Agreement.)

YANKEE GAS LEASEHOLD INTEREST -- WATERFORD

Lease Agreement between Parkway South LLC and Yankee Gas Services Company dated May 3, 1999.
Description of leased premises:

A certain portion of the land known as 179 Cross Road, Waterford, Connecticut comprising 1.18 Ac. +/-.
Said premises are subject to:

1. Sanitary sewer easement recorded in Volume 380, Page 579 of the Waterford Land Records.

2. Pole line easement recorded in Volume 116, Page 395 of the Waterford Land Records.

3. Drainage rights recorded in Volume 114, Page 588 of the Waterford Land Records.

NOTES:

1. Special Permit to allow the sales, service and repair of power tools, etc. recorded December 15, 1987 in Volume 336, Page 733 of the Waterford Land Records.

2. Variance regarding variable landscaped buffer strip dated April 12, 1984 and recorded in Volume 281, Page 517 of the Waterford Land Records.

YANKEE GAS LEASEHOLD INTEREST -- DANBURY

Lease Agreement between Yankee Gas Services Company and Philip Edelstein (Manager of PHICAJI, LLC, record owner) dated January 20, 2000.

Description of leased premises:

The property, together with all buildings, structures and improvements situated there upon, located in the City of Danbury, Connecticut and commonly known as 24 Finance Drive. Said leased premises consisting of approximately 3.006 acres of land with a building containing +I- 10,000 rentable square feet as more particularly shown on the map entitled "MAP PEPARED FOR D. WATSON, P.E., CONNECTICUT LICENSE #2106" dated June 7, 1972 and filed on the Danbury, CT land records as Map No. 9115.

Said premises are subject to:

1. Riparian rights in and to the Still River.

2. Twenty-foot drainage easement shown on Map No. 5106.

3. Notes, conditions, facts, and easements shown on Maps Nos. 4660, 8456, 8741 and 9115.

4. Easement and right to erect, locate and maintain poles, wires, crossarms, and other usual fixtures and appurtenances for electric transmission, from The Industrial Land Corp. to The Housatonic Public Service Company, dated April 6, 1955 and recorded May 17, 1955 in Volume 297, Page 10 of the Danbury Land Records.

5. Electric Distribution Easement from The Industrial Land Corporation to The Connecticut Light and Power Company, dated January 11, 1963 and recorded January 23, 1963 in Volume 386, Page 339 of the Danbury Land Records.

6. Gas Distribution Easement from The Industrial Land Corporation to The Connecticut Light and Power Company, dated April 2, 1963 and recorded November 6, 1963 in Volume 397, Page 109 of the Danbury Land Records.

7. Obligation to maintain Augusta Drive and Augusta Drive Extension, as set forth in a Warranty 'Deed from The Industrial Land Corporation to Seymour R. Powers, dated February 15, 1968 and recorded February 26, 1968 in Volume 458, Page 175 of the Danbury Land Records; as modified by documents recorded in Volume 493, Page 292, Volume 682, Page 567, Volume 727, Page 797, and Volume 765, Page 40, all of the Danbury Land Records.

8. Sewer Easement from Seymour R. Powers and The Industrial Land Corporation to the City of Danbury, dated February 16, 1972 and recorded March 13, 1972 in Volume 512, Page 292 of the Danbury Land Records (Map No. 4995).

9. Annual maintenance charge for Augusta Drive and Finance Drive Extension as set forth in a Warranty Deed from Stephen L. Griss, Carole J. Kolsky, Trustees, Melvyn J. Powers and Union Trust Company, Trustees, and Mary P. Powers; to Fred L. Baker, Trustee, dated July 21, 1988 and recorded August 3, 1988 in Volume 893, Page 627 of the Danbury Land Records.

10. Sewer Easement for installation and maintenance of sewer lines from Philip Edelstein to the City of Danbury, dated August 29, 1989 and recorded March 19, 1990 in Volume 947, Page 653 of the Danbury Land Records (Map No. 9115).

EXHIBIT A

[FORM OF FIRST MORTGAGE BOND, 5.26% SERIES H, DUE 2019
FORM OF LEGEND]

THIS SECURITY HAS NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (THE "1933 ACT"). THE HOLDER HEREOF, BY PURCHASING THIS SECURITY, AGREES FOR THE BENEFIT OF YANKEE GAS SERVICES COMPANY (THE "COMPANY") AND PRIOR HOLDERS THAT THIS SECURITY MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) TO THE COMPANY (UPON REDEMPTION THEREOF OR OTHERWISE), (2) SO LONG AS THIS SECURITY IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A, TO A PERSON WHO THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER, WITHIN THE MEANING OF RULE 144A UNDER THE 1933 ACT, IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (3) IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH REGULATION S UNDER THE 1933 ACT, (4) PURSUANT TO AN EXEMPTION FROM REGISTRATION IN ACCORDANCE WITH RULE 144 (IF AVAILABLE) UNDER THE 1933 ACT, (5) IN RELIANCE ON ANOTHER EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT, SUBJECT TO THE RECEIPT BY THE COMPANY OF AN OPINION OF COUNSEL TO THE EFFECT THAT SUCH TRANSFER IS IN COMPLIANCE WITH THE 1933 ACT OR (6) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE 1933 ACT, SUBJECT (IN THE CASE OF CLAUSES (2), (3), (4) AND (5)) TO THE RECEIPT BY THE COMPANY OF A CERTIFICATION OF THE TRANSFEROR (WHICH, IN THE CASE OF CLAUSE (4), MAY BE A COPY OF FORM 144 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION) TO THE EFFECT THAT SUCH TRANSFER IS EXEMPT FROM THE REGISTRATION REQUIREMENTS OF THE 1933 ACT, AND IN EACH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY JURISDICTION OF THE UNITED STATES. THE HOLDER OF THIS SECURITY WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SECURITY FROM IT OF THE RESALE RESTRICTIONS REFERRED TO HEREIN.

Yankee Gas Services Company
First Mortgage Bonds,
5.26 % Series H, Due 2019

CUSIP Number

No. H -

Principal Amount: $

Stated Maturity of Principal: January 1, 2019 Applicable Rate: 5.26

Interest Payment Dates: May 1 and November 1, commencing May 1, 2005 and at the Stated Maturity of the principal

Yankee Gas Services Company, a specially chartered Connecticut corporation (hereinafter called the "Company", which term includes any successor corporation under the Indenture hereinafter referred to), for value received, hereby promises to pay to [], or registered assigns, at the Stated Maturity set forth above, the Principal Amount set forth above (or so much thereof as shall not have been paid upon prior redemption) and to pay interest (computed on the basis of a 360-day year of twelve 30-day months) thereon from the date of issuance hereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for, on each Interest Payment Date set forth above in each year at the Applicable Rate set forth above. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in said Indenture, be paid to the Person in whose name this Bond (or one or more Predecessor Bonds, as defined in said Indenture) is registered at the close of business on the Regular Record Date for such interest, which shall be the 15th day (whether or not a business day) of the calendar month next preceding such Interest Payment Date. Any such interest not so punctually paid or duly provided for shall be paid to the Person in whose name this Bond is registered on the business day immediately preceding the date of such payment. If all or any portion of the principal of, or the premium (if any) or interest on, this Bond shall not be paid when due, the amount not so paid shall bear interest at the lesser of (x) the highest rate allowed by applicable law or (y) the greater of (i) the Prime Rate (as defined in the Bond Purchase Agreements) or (ii) 6.26% (the Applicable Rate plus 1 % per annum).

The principal and the Redemption Price of, and the interest on, this Bond shall be payable at the principal corporate trust office of The Bank of New York, in New York, New York. All such payments shall be made in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts.

This Bond is one of a duly authorized issue of Bonds of the Company designated as its "First Mortgage Bonds" (herein called the "Bonds"), issued and to be issued in one or more series under, and all equally and ratably secured by, an Indenture of Mortgage and Deed of Trust, dated as of July 1, 1989 (herein, together with any indenture or instruments supplemental thereto, including the First Supplemental Indenture dated as of April 1, 1992, the Second Supplemental Indenture dated as of December 1, 1992, the Third Supplemental Indenture dated as of June 1, 1995, the Fourth Supplemental Indenture dated as of April 1, 1997, the Fifth Supplemental Indenture dated as of January 1, 1999, the Sixth Supplemental Indenture dated as of January 1,

2004 and the Seventh Supplemental Indenture dated as of November 1, 2004, called the "Indenture"), between the Company and The Bank of New York, successor to Fleet National Bank (formerly known as The Connecticut National Bank), as Trustee (herein called the "Trustee," which term includes any successor Trustee under the Indenture). Reference is hereby made to the Indenture for a description of the properties thereby mortgaged, pledged and assigned, the nature and extent of the security, the respective rights thereunder of the Holders of the Bonds, the Trustee and the Company, and the terms upon which the Bonds are, and are to be, authenticated and delivered. All capitalized terms used in this Bond which are not defined herein shall have the respective meanings ascribed thereto in the Indenture. Reference is also made to the Bond Purchase Agreements, as defined in the Seventh Supplemental Indenture, for a further description of the respective rights of the Holders of the Series H Bonds, the Company and the Trustee, and the terms applicable to the Series H Bonds.

As provided in the Indenture, the Bonds are issuable in series which may vary as in the Indenture provided or permitted. This Bond is one of the series specified in its title.

The Bonds are not subject to any sinking fund or mandatory scheduled redemption prior to final maturity.

As provided in the Indenture, at the option of the Company, the Series H Bonds shall be redeemable in whole at any time or in part from time to time, prior to their Stated Maturity, at a redemption price equal to the principal amount of the Series H Bonds being prepaid plus accrued interest thereon to the date of such redemption together with a premium equal to the then applicable Make-Whole Amount.

The Company will give notice of any optional redemption of the Series H Bonds pursuant to Section 2.03 of the Seventh Supplemental Indenture to each Holder thereof not less than 30 days nor more than 60 days before the date fixed for such optional redemption, specifying (a) such date, (b) the principal amount of the Holder's Bond to be redeemed on such date, (c) that a premium may be payable, (d) the estimated premium, calculated as of the day such notice is given and (e) the accrued interest applicable to the redemption. Such notice of redemption shall also certify all facts, if any, which are conditions precedent to any such redemption. Notice of redemption having been so given, the aggregate principal amount of the Series H Bonds specified in such notice, together with accrued interest thereon, and the premium, if any, payable with respect thereto shall become due and payable on the redemption date specified in such notice. Two business days prior to the redemption date specified in such notice of optional redemption, the Company shall provide the Trustee and each Holder of a Bond written notice of whether or not any premium is payable in connection with such redemption, the premium, if any, calculated as of the second business day prior to the redemption date, and a reasonably detailed computation of the Make-Whole Amount.

Bonds (or portions thereof) for whose redemption and payment provision is made in accordance with the Indenture shall thereupon cease to be entitled to the lien of the Indenture and shall cease to bear interest from and after the date fixed for redemption (in each event, so long as the payment due on any such date shall be made). The principal amount of the Series H Bonds to be redeemed upon any optional redemption thereof shall be applied pro rata to all such Series H Bonds Outstanding on the Redemption Date.

If an Event of Default, as defined in the Indenture, shall occur, the principal of the Series H

Bonds may become or be declared due and payable in the manner and with the effect provided in the Indenture and the Bond Purchase Agreements.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Bonds under the Indenture at any time by the Company with the consent of the Holders of a majority in aggregate principal amount of the Bonds of all series at the time Outstanding affected by such modification. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of Bonds at the time Outstanding on behalf of the Holders of all the Bonds, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver agreed to as set forth above by the Holder of this Bond shall be conclusive and binding upon such Holder and upon all future Holders of this Bond and of any Bond issued upon the transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Bond.

No reference herein to the Indenture and no provision of this Bond or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of (and premium, if any) and interest on this Bond at the times, places and rates, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, this Bond is transferable on the Bond Register of the Company, upon surrender of this Bond for transfer at the office or agency of the Company in New York, New York, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Bond Registrar, duly executed by the Registered Holder hereof or by his attorney duly authorized in writing, and thereupon one or more new Bonds of the same series, or authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

All Bonds of this series shall be fully interchangeable, and, upon surrender at the office or agency of the Company in a Place of Payment therefor, shall be exchangeable for other Bonds of this series of a different authorized denomination or denominations, as requested by the Holder surrendering the same.

No service charge shall be made for any transfer or exchange hereinbefore referred to, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

The Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Bond is registered as the owner hereof for the purpose of receiving payment as herein provided and for all other purposes, whether or not this Bond is overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

Unless the certificate of authentication hereon has been executed by the Trustee or Authenticating Agent by manual signature, this Bond shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

[THIS SPACE INTENTIONALLY LEFT BLANK]

[Signature page for Yankee Gas Services Company, First Mortgage Bond, 5.26% Series H, Due 2019]

IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed under its corporate seal.

Dated:_____

YANKEE GAS SERVICES COMPANY

By:_____
Name:
Title:

Attest:

_____

This is one of the Bonds of the series designated therein referred to in the within-mentioned Indenture.

THE BANK OF NEW YORK, as Trustee By

By _____
Authorized Officer

Exhibit 10.9.2

2000 AMENDATORY AGREEMENT

This Agreement, dated as of the 28th day of July, 2000, is entered into by and between Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and The Connecticut Light and Power Company ("Purchaser").

For good and valuable consideration, the receipt of which is hereby acknowledged, it is agreed as follows:

I. Basic Understandings

On April 7, 2000, upon direction from its Board of Directors, Connecticut Yankee filed an Offer of Settlement in a proceeding before the Federal Energy Regulatory Commission ("FERC"), Docket No. ER97-913-000, to settle the claims related to the collections to be made by Connecticut Yankee over the remaining terms of the Additional Power Contract, between Connecticut Yankee and the Purchaser, dated as of April 30, 1984 ("Additional Power Contract"), the 1987 Supplementary Power Contract between Connecticut Yankee and the Purchaser, dated as of April 1, 1987 (" 1987 Supplementary Power Contract"), and the December 4, 1996 Amendatory Agreement between Connecticut Yankee and Purchaser, which amended the 1987 Supplementary Power Contract and the Additional Power Contract in various respects (the "1996 Amendatory Agreement"). The Offer of Settlement specifies that, if it is approved by FERC, Connecticut Yankee will implement necessary amendments to contracts between Connecticut Yankee and the Purchaser to effectuate the provisions of the Offer of Settlement. Among the provisions of the Offer of Settlement is a requirement that Connecticut Yankee abandon the use of the net unit investment methodology for calculating collections from its Purchasers for return on remaining equity. The new methodology to be used for each monthly bill to a Purchaser is simply to multiply the remaining equity balance times the monthly equivalent return on equity allowed by FERC. The Offer of Settlement also provides that funds previously collected by Connecticut Yankee for its pre-1983 spent nuclear fuel disposal liability to the U.S. Department of Energy ("DOE") and held in a

segregated fund established pursuant to the 1987 Supplementary Power Contract, may be used to pay the costs of storing spent nuclear fuel on-site until the DOE removes it. Finally, the Offer of Settlement provides that Connecticut Yankee must make an informational filing with FERC in advance of any acceleration of recovery of unamortized investment as contemplated under the terms and conditions of Section 3, Part D (iii) of the 1996 Amendatory Agreement.

In order to carry out the obligations undertaken in the Offer of Settlement, Connecticut Yankee and the Purchaser have agreed (a) to authorize the application of monies held in the segregated fund to meet costs of storing spent nuclear fuel and associated high level radioactive materials; (b) to change the methodology employed for calculating collections for return on equity; and (c) to require an advance informational filing be made with FERC prior to acceleration of amortization.

2. **Prior Contracts Preserved**

Except as expressly modified by this Agreement. the provisions of the Additional Power Contract. the 1987 Supplementary Power Contract. as amended by the 1996 Amendatory Agreement. as well as the 1996 Amendatory Agreement. remain in full force and effect, recognizing that the mutually accepted decision to shut down the Unit renders

moot those provisions which by their terms relate solely to continuing operation of the Unit.

3. **Amendment of Additional Power Contract**

A. The first paragraph of Section 7 of the Additional Power Contract is hereby

amended to read as follows:

> With respect to each month commencing on or after the commencement of the operative term of this contract, whether or not this contract continues fully or partially in effect. the Purchaser will pay Connecticut Yankee as deferred payment for the capacity and output of the Unit provided to the Purchaser by Connecticut Yankee prior to the permanent shutdown of the Unit on December 4, 1996, to the extent not otherwise paid in accordance with the Power Contract, but without duplication: an amount equal to the Purchaser's entitlement percentage of the sum of (a) the Total Decommissioning Costs for the month with respect to the Unit, plus (b) Connecticut Yankee's total operating expenses for the month with respect to the Unit, plus (c) an amount for operating income as determined in

accordance with this Section 7.

B. The second paragraph of Section 7 of the Additional Power Contract is hereby deleted.

C. The third paragraph of Section 7 of the Additional Power Contract is hereby deleted.

D. The fourth paragraph of Section 7 of the Additional Power Contract is hereby deleted.

E. The sixth paragraph of Section 7 of the Additional Power Contract is hereby deleted.

F. Subsection (iii) of the eighth paragraph of Section 7 of the Additional Power Contract is amended by substituting the words "remaining unamortized investment" for the words "net Unit investment".

G. Subsection (iii) of the eighth paragraph of Section 7 of the Additional Power Contract is further amended by adding the following sentence to the end thereof:

> Notwithstanding anything herein to the contrary. Connecticut Yankee shall make an informational filing with the Federal Energy Regulatory Commission prior to accelerating collections under this Paragraph.

H. The ninth paragraph of Section 7 of the Additional Power Contract is hereby deleted.

I. Section 7 of the Additional Power Contract is amended by adding to the end thereof the following paragraph:

> As used in this Section 7, "operating income" for any month shall mean the product of the equity investment, calculated as of the last day of the preceding month, and one-twelfth of the latest annual return on equity authorized for Connecticut Yankee by the Federal Energy Regulatory Commission or any successor regulatory agency.

4. Amendment of the 1987 Supplementary Power Contract

A. Section 2 of the 1987 Supplementary Power Contract is hereby deleted.

B. Section 8 of the 1987 Supplementary Power Contract is amended by revising the last two sentences thereof to read as follows:

> Funds previously collected by Connecticut Yankee from the Purchaser for the purpose of disposing of prior spent nuclear fuel and associated high level radioactive material shall also he paid into any such segregated fund, which may, with the approval of the board of directors of Connecticut Yankee, be combined with any trust established under Section 5 of this agreement. Connecticut Yankee further agrees that any funds collected from the Purchaser to meet such disposal costs which are not used for that purpose, either through payment of any amount due to a federal agency or other entity that disposes of the spent nuclear fuel and associated high level radioactive material or though payment of any costs associated with storage of said fuel and material pending its disposal, will be refunded to the Purchaser at the time final payment of such disposal costs is made to the U.S. Department of Energy.

C. Section 9 of the 1987 Supplementary Power Contract is hereby deleted.

5. Effective Date

This Agreement shall become effective upon receipt by the Purchaser of notice that Connecticut Yankee has entered into 2000 Amendatory Agreements, as contemplated by Section l herein, with each of the other Purchasers.

6. Interpretation

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of Connecticut.

7. Addresses

Except as the parties may otherwise agree. any notice. request. bill or other communication from one party to the other relating to this Agreement. or the rights, obligations or performance of the parties hereunder, shall be in writing and shall be effective upon delivery to the other party. Any such communication shall be considered as duly delivered when mailed to the respective post office address of the other party shown following the signatures of such other party hereto. or such other post office

address as may be designated by written notice given in the manner as provided in this Section.

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8. Corporate Obligations

This Agreement is the corporate act and obligation of the parties hereto.

9. Counterparts

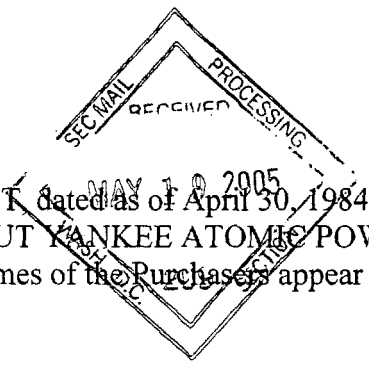
This Agreement may be executed in any number of counterparts and each executed counterpart shall have the same force and effect as an original instrument and as if all the parties to all of the counterparts had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

IN WITNESS WHEREOF, the parties have executed this Amendatory Agreement by their respective duly authorized officers as of the day and year first named above.

	CONNECTICUT YANKEE ATOMIC POWER COMPANY
	By: /s/ Thomas W. Bennet, Jr., Thomas V. Bennet, Jr., Its Vice President and Treasurer
	Address: 362 Injun Hollow Road, East Hampton, Connecticut
	THE CONNECTICUT LIGHT AND POWER COMPANY
	By: /s/ John B. Keane John B. Keane Its Vice President - Generation Divestiture
	Address: 49 Bainbridge Road West Hartford, CT 06119

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Exhibit 10.9.3



AMENDED AND RESTATED
ADDITIONAL POWER CONTRACT

AMENDED AND RESTATED ADDITIONAL POWER CONTRACT, dated as of April 30, 1984, as amended and restated as of the 1st day of July, 2004, between CONNECTICUT YANKEE ATOMIC POWER COMPANY ("Connecticut Yankee"), a Connecticut corporation, and (the names of the Purchasers appear in the attached Appendix A) (the "Purchaser").

In consideration of the following understandings and the respective undertakings of the parties, it is agreed as follows:

1. Basic Understandings

Connecticut Yankee was organized in 1962 to provide for the supply of power to its sponsoring utility companies (including the Purchaser). Connecticut Yankee constructed a nuclear electric generating unit of the pressurized water type, having a maximum net capability of approximately 582 megawatts electric, at a site adjacent to the Connecticut River at Haddam, Connecticut (said unit, together with the site and all related facilities owned or to be owned by Connecticut Yankee, being referred to herein as the "Unit"). On June 30, 1967, Connecticut Yankee was issued a full-term, operating license for the Unit from the Atomic Energy Commission (now the Nuclear Regulatory Commission, which, together with any successor agency or agencies, is hereafter called the "NRC"), which license expires on May 26, 2004, and the Unit commenced commercial operation on January 1, 1968.

The Unit is operated to supply power to the purchasers from Connecticut Yankee (collectively the "Purchasers"), each of which by a Power Contract dated as of July 1, 1964, as supplemented by Supplementary Power Contracts dated as of March 1, 1978, such Supplementary Power Contracts amended on August 22, 1980 and October 15, 1982 (collectively the "Power Contracts"), has undertaken to purchase a fixed percentage of the capacity and output of the Unit for a term extending through December 31, 1997. The names of the Purchasers and their respective percentages ("entitlement percentages") of the capacity and output of the Unit are as follows:

	Entitlement Percentage
The Connecticut Light and Power Company	34.5%
New England Power Company (for itself and as Successor to Montaup Electric Company	19.5%
The Connecticut Light and Power Company	34.5%
New England Power Company (for itself and as Western Massachusetts Electric Company	9.5%
The United Illuminating Company	9.5%
Boston Edison Company	9.5%
Central Maine Power Company	6.0%
Public Service Company of New Hampshire	5.0%
Cambridge Electric Light Company	4.5%
Central Vermont Public Service Corporation	2.0%

The Power Contracts have been supplemented most recently by Second Supplementary Power Contracts, dated as of 1984, between Connecticut Yankee and each of the Purchasers (the "Second

Supplementary Power Contracts"). The Second Supplementary Power Contracts provide for the collection of funds to defray the ultimate cost of decommissioning the Unit and to provide an allowance for potential taxes payable by Connecticut Yankee with respect to the decommissioning fund.

Connecticut Yankee and the Purchasers desire to provide for the orderly continuation of the sale and purchase of the capacity and output of the Unit during the useful life of the Unit to the extent that such useful life continues beyond the termination date of the Power Contracts and the Second Supplementary Power Contracts and to provide appropriate provisions for the collection of funds for, and the payment of, decommissioning costs and any other costs, including potential taxes, with respect to the Unit during and after the useful life of the Unit.

2. Effective Date, Term and Waiver

This contract shall become effective upon receipt by the Purchaser of notice that Connecticut Yankee has entered into Additional Power Contracts, as contemplated by Section 1 above, with each of the other Purchasers. The operative term of this contract shall commence on such date as may be authorized by the FERC and shall terminate on the date (the "End of Term Date") which is the later to occur of (i) 30 days after the date on which the last of the financial obligations of Connecticut Yankee which constitute elements of the payment calculated pursuant to Section 7 of this contract has been extinguished by Connecticut Yankee, or (ii) 30 days after the date on which Connecticut Yankee is finally relieved of all obligations under the last of any licenses (operating and/or possessory) which it now holds from, or which may hereafter be issued to it by, the NRC with respect to the Unit under applicable provisions of the Atomic Energy Act of 1954, as amended from time to time (the "Act").

The Purchaser hereby irrevocably waives its right to extend the contract term of its Power Contract pursuant to subsections (a) or (b) of Section 8 thereof.

3. Operation and Maintenance of the Unit

Connecticut Yankee will operate and maintain the Unit in accordance with good utility practice under the circumstances and all applicable law, including the applicable provisions of the Act and of any licenses issued thereunder to Connecticut Yankee. Within the limits imposed by good utility practice under the circumstances and applicable law, the Unit will be operated at its maximum capability and on a long hour use basis.

Outages for inspection, maintenance, refueling and repairs and replacements will be scheduled in accordance with good utility practice and insofar as practicable shall be mutually agreed upon by Connecticut Yankee and the Purchaser. In the event of an outage, Connecticut Yankee will use its best efforts to restore the Unit to service as promptly as practicable.

4. Decommissioning

After commercial operation of the Unit permanently ceases, Connecticut Yankee will decommission the Unit in a manner authorized by Connecticut Yankee's board of directors and approved by the NRC in accordance with the Act and the rules and regulations thereunder then in effect and by any agency having jurisdiction over decommissioning of the Unit.

It is understood that, pursuant to the 1987 Supplementary Power Contracts, the Purchasers are currently being billed for Total Decommissioning Costs which, as of the date of this contract, are being accumulated in a separate fund which was established for the purpose of reimbursing Connecticut Yankee for Decommissioning Expenses incurred in the process of decommissioning the Unit and that such billings ate subject to change in accordance with the provisions of the 1987 Supplementary Power Contracts, subject to the jurisdiction of the Federal Energy Regulatory Commission or any successor agency thereto (the "FERC"). It is contemplated that

sufficient funds will be accumulated pursuant to those contracts and paragraph 7 hereof to make payment to reimburse Connecticut Yankee for the full cost of decommissioning the Unit.

5. Purchaser's Entitlement

The Purchaser will, throughout the term of this contract, be entitled and obligated to take its entitlement percentage of the capacity and net electrical output of the Unit, at whatever level the Unit is operated or operable, whether more or less than 582 megawatts electric.

6. Deliveries and Metering

The Purchaser's entitlement percentage of the output of the Unit will be delivered to and accepted by the Purchaser at the step-up substation at the site. All deliveries will be made in the form of 3-phase, 60 cycle, alternating current at a nominal voltage of 345,000 volts. The Purchaser will make its own arrangements for the transmission of its entitlement percentage of the output of the Unit.

Connecticut Yankee will supply and maintain all necessary metering equipment for determining the quantity and conditions of supply of deliveries under this contract, will make appropriate tests of such equipment in accordance with good utility practice and as reasonably requested by the Purchaser, and will maintain the accuracy of such equipment within reasonable limits. Connecticut Yankee will furnish the Purchaser with such summaries of meter readings as the Purchaser may reasonably request.

7. Payment

With respect to each month commencing on or after the commencement of the operative term of this contract, whether or not this contract continues fully or partially in effect, the Purchaser will pay Connecticut Yankee as deferred payment for the capacity and output of the Unit provided to the Purchaser by Connecticut Yankee prior to the permanent shutdown of the Unit on December 4, 1996, to the extent not otherwise paid in accordance with the Power Contract, but without duplication: an amount equal to the Purchaser's entitlement percentage of the sum of (a) the Total Decommissioning Costs for the month with respect to the Unit, plus (b) Connecticut Yankee's total operating expenses for the month with respect to the Unit, plus (c) an amount for operating income as determined in accordance with Section 7.

"Equity investment" as of any date shall consist of the sum of(i) all amounts theretofore paid to Connecticut Yankee for all common capital stock theretofore issued, plus all amounts paid to Connecticut Yankee by any of its common stockholders as capital contributions or advances, less the sum of any amounts paid by Connecticut Yankee to its common stockholders in the form of stock retirements, repurchases or redemptions, return of capital or repayments of such contributions or advances; plus (ii) any credit balance in the capital surplus account not included under (i) and in the retained earnings account on the books of Connecticut Yankee as of such date.

"Uniform System" shall mean the Uniform System of Accounts prescribed by the FERC for Class A and Class B Public Utilities and Licensees, as from time to time in effect.

Connecticut Yankee's "operating expanses" shall include all amounts properly chargeable to operating expense accounts, less any applicable credits thereto, in accordance with the Uniform System; however, excluding for purposes of this contract Total Decommissioning Costs, but including for purposes of this contract:

(i) with respect to each month until the commencement of decommissioning of the Unit, the Purchaser's entitlement percentage of all expenses related to the storage or disposal of nuclear fuel or other radioactive materials, and all expenses related to protection and maintenance of the

Unit during such period, including to the extent applicable all of the various sorts of expenses included in the definition of "Decommissioning Expenses," to the extent incurred during the period prior to the commencement of decommissioning.

(ii) with respect to each month until expenses associated with disposal of pre-April 7, 1983 spent nuclear fuel have been fully covered by amounts which have been collected from Purchasers and paid to a segregated fund as contemplated by Section 8 of the 1987 Supplementary Power Contract, dated as of April 1, 1987, between Connecticut Yankee and the Purchaser, as amended (the "1987 Contract"), the Purchaser's entitlement percentage of previously uncollected expenses associated with disposal of such prior spent nuclear fuel, as determined in accordance with Section 10 of the 1987 Contract; and

(iii) with respect to each month until End of License Term, the Purchaser's entitlement percentage of monthly amortization of (a) the amount of any unamortized deferred expenses, as permitted from time to time by the Federal Energy Regulatory Commission or its successor agency, plus (b) the remaining unamortized amount of Connecticut Yankee's investment in plant, nuclear fuel and materials and supplies and other assets. Such amortization shall be accrued at a rate sufficient to amortize fully such unamortized deferred expenses and Connecticut Yankee's investments in plant, nuclear fuel and materials and supplies or other assets over a period extending to June 29, 2007.

As used herein, "End of License Term" means June 29, 2007 or such later date as may be fixed, by amendment to the NRC Facility Operating License for the Unit, as the end of the term of the Facility Operating License.

"Total Decommissioning Costs" for any month shall mean the sum of (x) an amount equal to all accruals in such month to any reserve, as from time to time established by Connecticut Yankee and approved by its board of directors, to provide for the ultimate payment of the Decommissioning Expenses of the Unit, plus (y), during the Decommissioning Period, the Decommissioning Expenses for the month, to the extent such Decommissioning Expenses are not paid with funds from such reserve, plus (z) Decommissioning Tax Liability for such month. It is understood (i) that funds received pursuant to clause (x) may be held by Connecticut Yankee or by an independent trust or other separate fund, as determined by said board of directors, (ii) that, upon compliance with applicable regulatory requirements, the amount, custody and/or timing of such accruals may from time to time during the term hereof be modified by said board of directors in its discretion or to comply with applicable statutory or regulatory requirements or to reflect changes in the amount, custody or timing of anticipated Decommissioning Expenses, and (iii) that the use of the term "to decommission" herein encompasses compliance with all requirements of the NRC for permanent cessation of operation of a nuclear facility and any other activities reasonably related thereto, including provision for the interim storage of spent nuclear fuel. A schedule for the collection of Total Decommissioning Costs is in Appendix B. "Decommissioning Expenses" shall include all expenses of decommissioning the Unit, and all expenses relating to ownership and protection of the Unit during the Decommissioning Period, and shall also include the following:

(1) All costs and expenses of any NRC-approved method of removing the Unit from service, including without limitation: dismantling, mothballing and entombment of the Unit; removing nuclear fuel and other radioactive material to temporary and/or permanent storage sites; construction, operation, maintenance and dismantling of a spent fuel storage facility; decontaminating, restoring and supervising the site; and any costs and expenses incurred in connection with proceedings before governmental authorities relating to any authorization to decommission the Unit or remove the Unit from service;

(2) All costs of labor and services, whether directly or indirectly incurred, including without limitation, services of foremen, inspectors, supervisors, surveyors, engineers, security personnel, counsel and accountants, performed or rendered in connection with the decommissioning of the Unit and the removal of the Unit from service, and all costs of materials, supplies, machinery, construction equipment and apparatus acquired or used (including rental charges for machinery, equipment or apparatus hired) for or in connection with the decommissioning of the Unit and the removal of the Unit from service, and all administrative costs, including services of counsel and financial advisers of any applicable independent mint or other separate fund; it being understood that any amount, exclusive of proceeds of insurance, realized by Connecticut Yankee as salvage on any machinery, construction equipment and apparatus, the cost of which was charged to Decommissioning Expense, shall be treated as a reduction of the amounts otherwise chargeable on account of the costs of decommissioning of the Unit; and

(3) All overhead costs applicable to the Unit during the Decommissioning Period, or accrued during such period, including without limiting the generality of the foregoing, taxes (other than taxes on or in respect of income), charges, license fees, excises and assessments, casualties, health care costs, pension benefits and other employee benefits, surety bond premiums and insurance premiums. Schedules for the collection of pension costs and costs of Post-retirement Benefits Other than Pensions (PBOPs) are in Appendix C and D, respectively.

"Decommissioning Tax Liability" for any month shall be an amount established by Connecticut Yankee and approved by its board of directors to meet possible income tax obligations, which amount shall not exceed: the amount to be included in the clause (x) portion of Total Decommissioning Costs for such month multiplied by a fraction whose numerator is equal to the combined highest applicable statutory Federal and state marginal income tax rate and whose denominator is equal to one minus the combined highest statutory Federal and state marginal income tax rate.

"Decommissioning Period" shall mean the period commencing with the notification by Connecticut Yankee to the NRC of a decision of the board of directors of Connecticut Yankee to cease permanently the operation of the Unit for the purpose of producing electric energy and ending with the date when Connecticut Yankee has completed the decommissioning of the Unit and the restoration of the site and has been relieved of all its obligations under the last of any licenses issued to it by the NRC.

8. Billing

Connecticut Yankee will bill the Purchaser, no later than ten (10) days after the end of any month, for all amounts payable by the Purchaser with respect to such particular month pursuant to Section 7 hereof. Such bills will be rendered in such detail as the Purchaser may reasonably request and may be rendered on an estimated basis subject to corrective adjustments in subsequent billing periods. All bills shall be due and payable when rendered and any amount remaining unpaid fifteen (15) days following the date of receipt of bills shall bear interest at an annual rate equal to two percent (2%), in excess of the current prime rate then in effect at Fleet Bank, from the due date to the date payment is received by Connecticut Yankee.

9. Decommissioning Fund

Connecticut Yankee agrees to cause an appropriate decommissioning reserve to be maintained in accordance with applicable regulatory requirements. Connecticut Yankee has established an independent trust or other separate fund (the "Connecticut Yankee Trust") which has the necessary powers to hold and invest all funds collected for the decommissioning of the Unit and disburse the same to reimburse Connecticut Yankee for such costs when actually incurred for decommissioning of the Unit or removal of the Unit from service. If during the term of the Connecticut Yankee Trust applicable legislation or regulations are promulgated which so permit or require, or an alternative entity is created for funding decommissioning of the Unit, the Connecticut

Yankee Trust has the authority, with the concurrence of Connecticut Yankee, to transfer its trust estate to such newly authorized entity for the purpose of providing for the decommissioning of the Unit or removal of the Unit from service.

Connecticut Yankee agrees to pay to, or cause to be paid to, the Connecticut Yankee Trust or any successor trust approved by the board of directors of Connecticut Yankee all funds collected hereunder for the express purpose of decommissioning the Unit or removing collections have been resolved, any funds collected hereunder to meet Decommissioning Tax Liability which are not used for that purpose will be refunded to the Purchaser.

10. Cancellation of Contract

If either

(i) the Unit is damaged to the extent of being completely or substantially completely destroyed, or

(ii) the Unit is taken by exercise of right of eminent domain or a similar right of power, then and in any such case, the Purchaser may cancel the provisions of this contract, except that in all cases other than those described in clause (ii) above, the Purchaser shall be obligated to continue to make the payments of Total Decommissioning Costs and the other payments required by Section 7 and the provisions of that Section and the related provisions of this contract shall remain in full force and effect until the End of Term Date, it being recognized that the costs which Purchaser is required to pay pursuant to Section 7 represent deferred payments in connection with power heretofore delivered by Connecticut Yankee hereunder. Such cancellation shall be effected by written notice given by the Purchaser to Connecticut Yankee. In the event of such cancellation, all continuing obligations of the parties hereunder as to subsequently incurred costs of Connecticut Yankee other than the obligations of the Purchaser to continue to make the payments required by Section 7 shall cease forthwith. Notwithstanding the foregoing, the applicable provisions of this contract shall continue in effect after the cancellation hereof to the extent necessary to permit final billings and adjustments hereunder with respect to obligations incurred through the date of cancellation and the collection thereof. Any dispute as to the Purchaser's right to cancel this contract pursuant to the foregoing provisions shall be referred to arbitration in accordance with the provisions of Section 13.

Notwithstanding anything in this contract elsewhere contained, the Purchaser may cancel this contract or be relieved of its obligations to make payments hereunder only as provided in the next preceding paragraph of this Section 10. Further, if for reasons beyond Connecticut Yankee's reasonable control, deliveries are not made as contemplated by this contract, Connecticut Yankee shall have no liability to the Purchaser on account of such non-delivery.

11. Insurance

Connecticut Yankee presently has in effect, and hereafter with at all times maintain until the expiration of the term hereof, insurance to cover its "public liability" for personal injury and property damage resulting from a "nuclear incident" (as those terms are defined in the Act), with limits not less than Connecticut Yankee may be required to maintain to qualify for governmental indemnity under the Act and shall maintain an indemnification agreement with the NRC as provided by the Act. Connecticut Yankee will also at all times maintain such other types of liability insurance, including workmen's compensation insurance, in such amounts as is customary in the case of other similar electric utility companies or as may be required by law.

Connecticut Yankee will at all times keep insured such portions of the Unit as are of a character usually insured by electric utility companies similarly situated and operating like properties, against the risk of a

"nuclear incident" and such other risks as electric utility companies, similarly situated and operating like properties, usually insure against, and such insurance shall, to the extent available, be carried in amounts sufficient to prevent Connecticut Yankee from becoming a co-insurer. Such insurance shall, to the extent available, be carried in an amount at least equal to the original cost of the insured facilities, less accrued depreciation thereon.

12. Audit

Connecticut Yankee's books and records (including metering records) shall be open to reasonable inspection and audit by the Purchaser.

13. Arbitration

In case any dispute shall arise as to the interpretation or performance of this contract which cannot be settled by mutual agreement, such dispute shall be submitted to arbitration. The parties shall if possible agree upon a single arbitrator. In case of failure to agree upon an arbitrator within fifteen (15) days after the delivery by either party to the other of a written notice requesting arbitration, either party may request the American Arbitration Association to appoint the arbitrator. The arbitrator, after opportunity for each of the parties to be heard, shall consider and decide the dispute and notify the parties in writing of his decision. Such decision shaft be binding upon the parties, and the expenses of the arbitration shall be borne equally by them.

14. Regulation

This contract, and all rights, obligations and performance of the parties hereunder, are subject to all applicable state and Federal law and to all duly promulgated orders and other duly authorized action of governmental authorities having jurisdiction.

15. Assignment

This contract shall be binding upon and shall inure to the benefit of, and may be performed by, the successors and assigns of the parties, except that no assignment, pledge or other transfer of this contract by either party shall operate to release the assignor, pledgor or transferor from any of its obligations under this contract unless consent to the release is given in writing by the other party, or, if the other party has theretofore assigned, pledged or otherwise transferred its interest in this contract, by the other party's assignee, pledgee or transferee, or unless such transfer is incident to a merger or consolidation with, or transfer of all or substantially all of the assets of the transferor to, another Purchaser which shall, as a part of such succession, assume all the obligations of the transferor under this contract.

16. Right of Setoff

The Purchaser shall not be entitled to set off against the payments required to be made by it under this contract (i) any amounts owed to it by Connecticut Yankee, or (ii) the amount of any claim by it against Connecticut Yankee. However, the foregoing shall not affect in any other way the Purchaser's right and remedies with respect to any such amounts owed to it by Connecticut Yankee or any such claim by it against Connecticut Yankee.

17. Amendments

Upon authorization by Connecticut Yankee's board of directors of uniform amendments to all the Additional Power Contracts, Connecticut Yankee shall have the right to amend the provisions of Section 7 hereof by serving an appropriate statement of such amendment upon the Purchaser and filing the same remedies the FERC (or such other regulatory agency as may have jurisdiction in the premises) in accordance with the

provisions of applicable laws and any rules and regulation thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order issued by such agency. All other amendments to this contract shall be by mutual agreement, evidenced by a written amendment signed by the parties hereto.

18. Interpretation

The interpretation and performance of this contract shall be in accordance with and controlled by the law of the State of Connecticut.

19. Addresses

Except as the parties may otherwise agree, any notice, request, bill or other communication from one party to the other, relating to this contract, or the rights, obligations or performance of the parties hereunder, shall be in writing and shall be effective upon delivery to the other party. Any such communication shall be considered as duly delivered when delivered in person or mailed by registered or certified mail, postage prepaid, to the respective post office address of the other party, or such other address as may be designated by written notice given as provided in this Section 19.

20. Corporate Obligations

This contract is the corporate act and obligation of the parties hereto, and any claim hereunder against any stockholder, director or officer of either party, as such, is expressly waived.

21. 18 CFR Part 35 Compliance

Connecticut Yankee and the Purchaser:. (a) acknowledge that FERC's new regulations concerning the designation and formatting of FERC-jurisdictional rate schedules, found at 18 CFR §§ 35.5 and 35.9 (2003), require the maintenance of a single composite, conformed rate schedule reflecting the operative provisions of the Additional Power Contracts and the 1987 Supplementary Power Contracts between Connecticut Yankee and all Purchasers, including any provisions thereof modified by this Agreement; and (b) agree that Connecticut Yankee's submission to FERC of a rate schedule complying with these regulations shall not alter the rights and obligations of Connecticut Yankee and the Purchaser, which shall continue to be governed by the Additional Power Contract and the 1987 Supplementary Power Contract, both as amended. The provisions of the Additional Power Contract and the 1987 Supplementary Power Contract, both as amended, remain in full force and effect, recognizing that the mutually accepted decision to shut down the Unit renders moot those provisions which by their terms relate solely to continuing operation of the Unit.

IN WITNESS WHEREOF the parties have agreed to this revised contract by their respective officers thereunto duly authorized as of the captioned date.

Appendix A

Names of Purchasers

NEW ENGLAND POWER COMPANY
(For itself and as successor in interest to Montaup Electric Company)

THE CONNECTICUT LIGHT AND POWER COMPANY

BOSTON EDISON COMPANY

CENTRAL MAINE POWER COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

CAMBRIDGE ELECTRIC LIGHT COMPANY

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

THE UNITED ILLUMINATING COMPANY

Appendix B

Schedule of Decommissioning Collections
(Annual Collections in $000's)

Year	Amount
2004	16,742
2005	93,002
2006	93,002
2007	93,002
2008	93,002
2009	93,002
2010	93,002
Total	$591,496

Appendix C

Schedule of Pension Collections

Year	Requirement
2005	800,000
2006	1,100,000
2007	2,408,591
Total	**$4,008,591**

Appendix D

Schedule of Post-retirement Benefits Other than Pensions Collections

Year	Requirement
2005	956,092
2006	956,092
2007	478,046
Total	**$2,390,230**

Exhibit 12

Ratio of Earnings to Fixed Charges
(In thousands)

Earnings, as defined:	2004	2003	2002	2001	2000
Net income before extraordinary item and cumulative effect of accounting change	$ 116,588	$ 121,152	$ 152,109	$ 220,124	$ 205,295
Income taxes	51,756	59,862	82,304	171,483	161,725
Equity in earnings of regional nuclear generating and transmission companies	2,592	4,487	11,215	3,090	13,667
Fixed charges, as below	277,965	267,805	291,610	313,113	344,108
Interest capitalized (not including AFUDC)	(600)	(1,058)	(2,085)	(684)	(15)
Preferred dividend security requirements of consolidated subsidiairies	(9,265)	(9,265)	(9,265)	(12,082)	(23,603)
Total earnings, as defined	$ 439,036	$ 442,983	$ 525,888	$ 695,044	$ 701,177
Fixed charges, as defined:					
Interest on long-term debt	$ 139,853	$ 126,259	$ 134,471	$ 147,049	$ 200,696
Interest on rate reduction bonds	98,899	108,359	115,791	87,616	-
Other interest	14,762	11,740	20,249	44,993	98,605
Rental interest factor	7,433	4,833	3,200	15,483	11,874
Amortized premiums, discounts and capitalized expenses related to indebtedness	7,153	6,291	6,549	5,206	9,315
Preferred dividend security requirements of consolidated subsidiairies	9,265	9,265	9,265	12,082	23,603
Interest capitalized (not including AFUDC)	600	1,058	2,085	684	15
Total fixed charges, as defined	$ 277,965	$ 267,805	$ 291,610	$ 313,113	$ 344,108
Ratio of Earnings to Fixed Charges	1.58	1.65	1.80	2.22	2.04

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 33-34622 and 33-40156 on Forms S-3 and Nos. 33-63023, 333-63144 and 333-121364 on Forms S-8 of our reports dated March 16, 2005, (which express an unqualified opinion and include explanatory paragraphs with respect to the Company's 2003 adoption of Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities* and the Company's restatement of the consolidated balance sheet as of December 31, 2003 and the related consolidated statement of cash flows for the year then ended), relating to the consolidated financial statements and consolidated financial statement schedules of Northeast Utilities, and our report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, dated March 16, 2005, (which expresses an unqualified opinion on management's assessment and an adverse opinion on the effectiveness of the Company's internal control over financial reporting because of a material weakness), all appearing in and incorporated by reference in this Annual Report on Form 10-K of Northeast Utilities for the year ended December 31, 2004.

We also consent to the incorporation by reference in Registration Statement Nos. 333-118276 of The Connecticut Light and Power Company, 333-116725 of Public Service Company of New Hampshire, and 333-108712 of Western Massachusetts Electric Company on Forms S-3 of our reports dated March 16, 2005, relating to the consolidated financial statements and consolidated financial statement schedules of The Connecticut Light and Power Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company, respectively, all appearing in and incorporated by reference in this Annual Report on Form 10-K for each of the respective companies for the year ended December 31, 2004.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Hartford, Connecticut
March 16, 2005

EXHIBIT 21

SUBSIDIARIES OF THE REGISTRANT

	State of Incorporation
Northeast Utilities (a Massachusetts business trust)	MA
The Connecticut Light and Power Company	CT
CL&P Funding LLC	DE
CL&P Receivables Corporation	CT
Holyoke Water Power Company	MA
Holyoke Power and Electric Company	MA
North Atlantic Energy Corporation	NH
North Atlantic Energy Service Corporation	NH
Northeast Nuclear Energy Company	CT
Northeast Utilities Service Company	CT
NU Enterprises, Inc.	CT
Select Energy Services, Inc.	MA
Select Energy Contracting, Inc.	MA
Mode 1 Communications, Inc.	CT
Northeast Generation Company	CT
Northeast Generation Services Company	CT
E. S. Boulos Company	CT
Woods Electrical Co., Inc.	CT
Select Energy, Inc.	CT
Select Energy New York, Inc.	DE
Woods Network Services, Inc.	CT
Public Service Company of New Hampshire	NH
PSNH Funding LLC	DE
PSNH Funding LLC 2	DE
The Quinnehtuk Company	MA
The Rocky River Realty Company	CT
Western Massachusetts Electric Company	MA
WMECO Funding LLC	DE
Yankee Energy System, Inc.	CT
Yankee Gas Services Company	CT

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles W. Shivery, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Northeast Utilities (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Northeast Utilities (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Charles W. Shivery and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Charles W. Shivery
(Signature)
Charles W. Shivery
Chairman, President and Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of The Connecticut Light and Power Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of The Connecticut Light and Power Company (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Hampshire (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Public Service Company of New Hampshire (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 31

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Cheryl W. Grisé, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David R. McHale, certify that:

1. I have reviewed this Annual Report on Form 10-K of Western Massachusetts Electric Company (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2005

/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

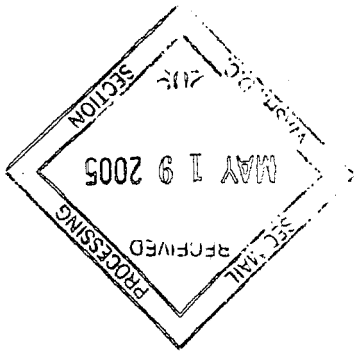
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Western Massachusetts Electric Company (the registrant) on Form 10-K for the period ending December 31, 2004 as filed with the Securities and Exchange Commission (the Report), we, Cheryl W. Grisé and David R. McHale, certify, pursuant to 18 U.S.C. Sec. 1350, as adopted pursuant to Sec. 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the registrant.

/s/ Cheryl W. Grisé
(Signature)
Cheryl W. Grisé
Chief Executive Officer



/s/ David R. McHale
(Signature)
David R. McHale
Senior Vice President and Chief Financial Officer

March 16, 2005

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

