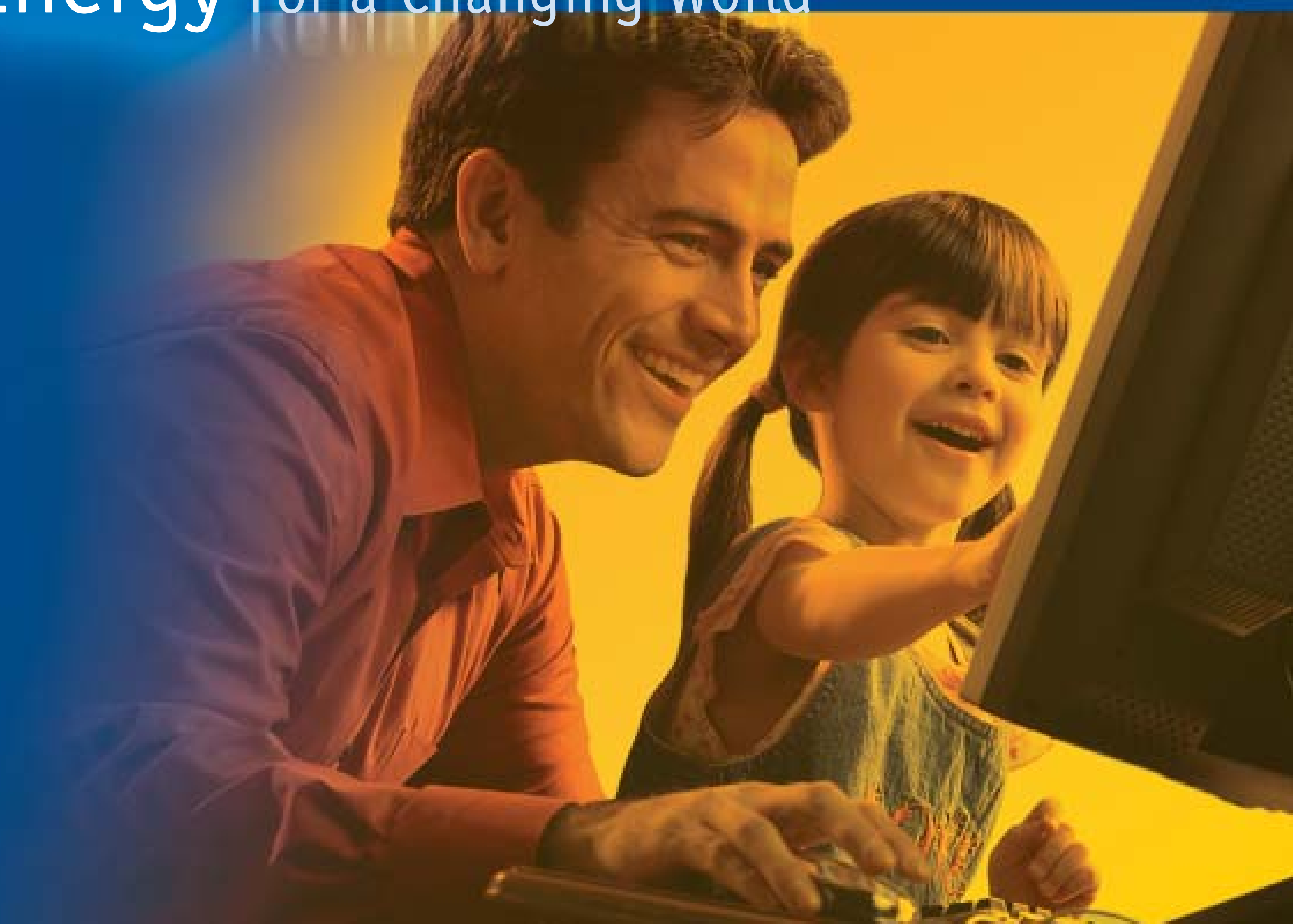
Northeast Utilities
2002 Annual Report

Energy For a Changing World



Energy is at the heart of everything we do.

Our customers' energy needs are changing.

From the energy of our 6,560 employees, to the electric and natural gas energy we deliver to 2 million customers in Connecticut, western Massachusetts and New Hampshire, to anticipating the region's needs for an upgraded energy transmission system, to managing our competitive businesses from Maine to Maryland, we take to heart our vital role supporting customers and communities with essential service. And we deliver on that commitment every day.

As technology brings advances and new applications to homes and businesses, our customers' energy needs change and grow. Our more than 100 years serving the northeast have encompassed a sea change. Today, customers use sophisticated computers at home and work, and businesses require unprecedented power quality and reliability. Northeast Utilities provides both the stability and flexibility to weather change and deliver solutions to meet customers' changing energy needs with strength and confidence. Our brand is built on that promise.

Michael G. Morris
Chairman, President and Chief Executive Officer

Financial Highlights

(Thousands of dollars, except share information and statistical data)	*2002*	*2001*	*% Change*
Operating Revenues	$ 5,216,321	$ 5,968,220	(13)%
Operating Income	466,655	539,174	(13)%
Net Income	152,109	243,510	(38)%
Fully Diluted Earnings Per Common Share	$ 1.18	$ 1.79	(34)%
Fully Diluted Common Shares Outstanding *(Average)*	129,341,360	135,917,423	(5)%
Dividends Per Share	$ 0.53	$ 0.45	18%
Sales of Electricity *(kWh-millions)*	119,859	85,984	39%
Electric Customers *(Average)*	1,809,528	1,793,071	1%
Gas Customers *(Average)*	190,855	190,998	—%
Property, Plant and Equipment, Net	$ 4,728,369	$ 4,472,977	6%

Our Vision:

To become the highest performing regional provider of energy products and services, strengthening our region's security, stability and vitality.

Delivering: Value

Dear fellow shareholder, employee, customer, and business partner:

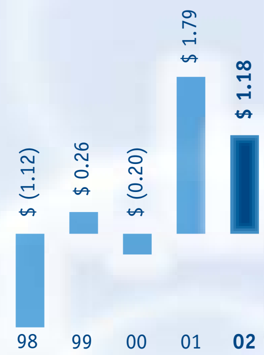
In 2002 Northeast Utilities' employees once again demonstrated a dedication to excellence, and their efforts provided the stability and reliability you value. 2002 marks milestone achievements – our financial position is stronger today than at any time in the past 30 years, and our standing in the regional energy market holds strong. Our role in high-voltage electric transmission continues to distinguish us as an industry leader. Across both our regulated and competitive businesses, from serving families to municipalities to major industries, people rely on us to provide the "energy for a changing world."

2002 was a year of solidly grounded business practices through which we:

- Continued raising our dividend and buying back shares, enhancing the value of your investment.
- Maintained the strongest credit ratings in decades, increasing the credit position of NU as our industry's average credit profile declined.
- Delivered solid profits from all four regulated operating companies, while earning impressive customer service ratings.
- Completed the divestiture of nuclear generation, receiving fair treatment from regulators on the recovery of stranded costs.
- Avoided the billions of dollars of investment losses taken by companies with heavy merchant generation and overseas investments.

The year of change and uncertainty in our industry also brought challenges, chief among them the stock market decline. The Dow Jones Utility Average dropped by nearly 27 percent; by contrast, NU shares fell by just under 14 percent. Our reported earnings declined to $152.1 million, or $1.18 per fully diluted share in 2002 from $243.5 million, or $1.79 per fully diluted share, in 2001, due primarily to gains recorded in 2001 related to the sale of Millstone Station. Our 2002 results were further impacted by disappointing results in our competitive businesses, as discussed later in this letter.

With our employees as the foundation of every business and customer service success, NU is poised for further growth and profitability in 2003 and beyond. A six-point business strategy will serve as our compass to achieve increased market share and enhance your investment in our company.



Earnings per Common Share
(Dollars)

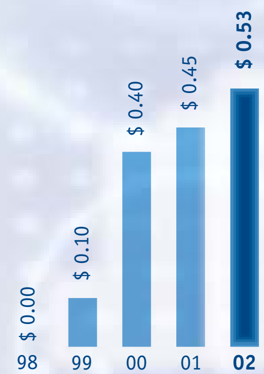
Business Ethics and Sound Business Practices

Ethics and integrity are the foundation on which we build NU's success, and we are proud of our record. As Congress and the federal Securities and Exchange Commission introduced changes in corporate governance, accounting and financial reporting, we scrutinized our operations and management practices based on an in-depth review we conducted. We certified the completeness and accuracy of our financial reporting, reflecting our full compliance with both the letter and spirit of the law. We continue to uphold this standard.

Lasting Partnerships

The energy business plays a unique and critical role in our society, with many touch points. Our collaborative partnerships with regional officials, community leaders and environmental organizations afford us a connection to our customers beyond the physical reach of power and gas lines. These relationships afford us the opportunity to represent our customers and bring pressing energy issues to the attention of national and local leaders.

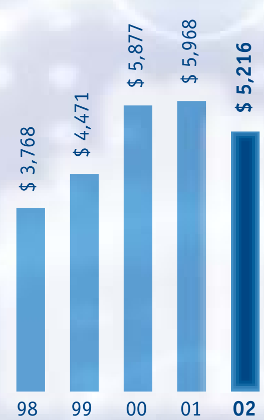
Working regionally with regulators and legislators, NU contributes to workable energy policy and rules. Locally, we will see a transition from Connecticut's four-year Standard Offer period, mandated by 1998 restructuring legislation and ending in 2003. We continue to support the Connecticut Department of Public Utility Control to ease the transition to 2004.



Dividends per Share
(Dollars)

Strong Financial Flexibility and Liquidity

NU's balance sheet is strong. Using the more than $4 billion received from selling most of our generating plants and securitizing our stranded costs, we paid off roughly half of the approximately $4.6 billion of debt, preferred stock and lease obligations held since the end of 1997. Virtually all our short-term debt has been paid as a result of the $384 million sale of our interest in the Seabrook nuclear units at the end of 2002. With NU securities remaining stable in 2002 despite hundreds of downgrades of other utilities' credit ratings and with our required refinancing obligations at a modest level, NU will maintain a strong balance sheet to retain our financial flexibility.



Revenues
(Dollars in Millions)

Rising Dividend and Successful Share Repurchase

Management expects to continue to grow the dividend in order to achieve one of the highest dividend growth rates in our industry. The NU Board of Trustees will continue to evaluate the company's dividend based on our earnings target and other factors. On May 14, 2002, the Board approved a 10 percent increase in the quarterly dividend to $0.1375 per share, effective with the third quarter of 2002. Similar dividends were declared for the fourth quarter of 2002 and the first quarter of 2003.

One of the best investments we can make is in our company, which is why we continue our share repurchase program. We have been pleased with its effect on our earnings per share in both 2002 and 2001. By repurchasing NU shares in the open market, we can spread our earnings and dividends across fewer shares. We spent more than $57 million in 2002 to repurchase some 3.7 million NU shares at an average price of about $15.78 per share. Our Board has authorized the repurchase of up to an additional 7 million shares in the first half of 2003. We will evaluate the program in light of industry liquidity standards and our capital program, which have both changed dramatically over the past two years.

Utilities are among the highest yielding stocks in the U.S., with dividends especially important to our investors. Consequently, we support President Bush's proposal to end the double taxation on dividends and again ask that you join us in that support.

Balanced Growth, With Reinvestment in Transmission and Distribution

Our vision of a region enjoying growth and vitality is intrinsically linked to ensuring the reliability and capacity of its energy infrastructure. With regular infusions of financial capital we are substantially reinvesting in our regulated businesses to provide customers a wider choice of energy supply and reliability improvements, as well as to deliver steady growth and profitability to our shareholders.

CL&P, exclusively a transmission and distribution business following the 2002 sales of its interests in the Seabrook and Vermont Yankee nuclear plants, continues to improve infrastructure, reliability and efficiency. Last year CL&P invested approximately $140 million in distribution lines, $35 million in the transmission system, $20 million in new meters and other customer services, and $17 million in substations. We expect to increase spending in these projects to ensure the reliability of bulk power supplies in Connecticut.

At Yankee Gas, our investments are bringing increased fuel choice and energy options, the underpinnings of successful local economic development initiatives and satisfied energy customers. Yankee Gas invested $70 million in new projects in 2002, about triple the amount before Yankee rejoined NU. We built the first natural gas distribution line into East Lyme, Connecticut, and continue to refine plans and secure approvals for a liquefied natural gas storage and production facility at our Waterbury work center. Our goal is to provide a secure, reliable natural gas supply that will help keep prices stable for our customers.

With New Hampshire experiencing the fastest growing economy in New England, PSNH invested some $110 million in new projects in 2002 and will continue to invest heavily in 2003 to expand the distribution and transmission system and upgrade the operations of its fossil-fueled plants.

At WMECO, completion of a new $4.4 million substation – the first substation built in 30 years in this service area – connects a gas-fired electric generation facility to the New England grid, offering customers yet another source of electricity.

Moving power from pockets of excess supply to pockets of heavy demand is a pressing need in the fast growing area of southwest Connecticut as well as elsewhere in New England. By investing more than $500 million in three major transmission projects over the next six years, we can enhance our ability to import into the region less expensive power generated from more environmentally friendly plants. This proposed investment would remedy the critical southwest Connecticut supply situation and, in the long-term, ensure the stability and reliability of power for our service area and all of New England.

Because we see this as a regional and national need, NU will create a stand-alone Transmission Business and will record its revenues and expenses in that business unit going forward in 2003. We join the New England ISO and the Federal Energy Regulatory Commission (FERC), as well as some of the state utility commissions, in advocating a more robust regional transmission system. To this end we will continue to advocate not only a business segregation but also a regulatory separation between intrastate and interstate commerce facilities as they are categorized by their actual function going forward. We fully support FERC's new incentive returns on equity capital and look forward to continuing to work with state and federal agencies to accomplish these very important national goals, which we believe will benefit our customers and our shareholders equally.

We are pleased to report progress in our southwest Connecticut projects as we continue to discuss these critical facilities in public forums and establish the basis and need for a new 345-kV electric transmission line along existing rights of way between Norwalk and Bethel; a second 345-kV transmission line along existing rights of way between Norwalk and Middletown; and replacement of an undersea electric transmission line between Norwalk and Northport, Long Island.

In the competitive arena, we continue to acquire niche companies in the energy services business, purchasing Woods Electrical and Woods Network Services in 2002 to complement the 2001 acquisitions of E.S. Boulos and Niagara Mohawk Energy Marketing, which was renamed Select Energy New York.

We regularly scrutinize potential new investments that can be accretive to shareholder value. We are purchasing the assets and franchise of Connecticut Valley Electric Company, which serves some 10,000 electric customers in western New Hampshire. We have not moved forward on purchasing additional merchant generation, feeling that the prices do not reflect true market conditions.

Competitive Businesses Must Make Meaningful Earnings Contribution

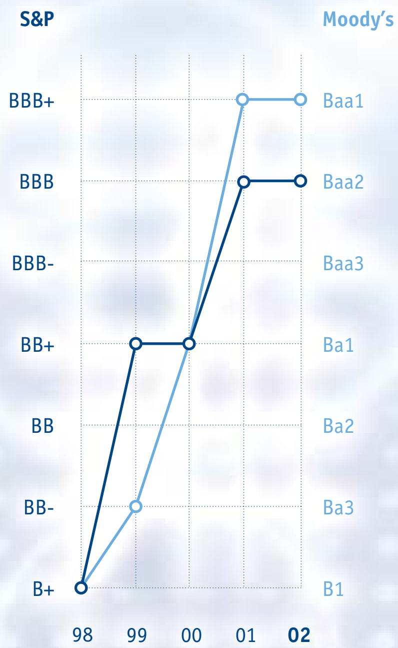
Chuck Shivery joined us in June 2002 as President and Chief Executive Officer of NU Enterprises, Inc. and has applied decades of experience to refine our competitive energy businesses and develop a new model for success. I believe we will see the results of his work this year.

The 2002 financial performance of NU's competitive energy businesses was very disappointing overall, with a collective loss of $54.1 million after modest earnings in 2001 and 2000.

In 2002 we faced challenges in competitive energy retail marketing and energy trading, as well as the continuation of the Connecticut Standard Offer contract. Even with our strong franchise in the northeast United States, selling electricity and natural gas to more than 10,000 large commercial, industrial and institutional customers, we were not insulated from first quarter 2002 losses due to one of the warmest winters on record. We are revamping our contract pricing to build more profit margin into our sales, while at the same time lowering our overhead. We are also managing our forward positions more conservatively to reduce the large swings in value that we have experienced in the past.

Our energy trading business lost significant sums of money last spring when natural gas prices spiked. Further, the number of firms with which we could trade fell sharply due to several deciding to exit the business. With fewer counterparties available to us, we lowered the level of capital at risk in the trading business considerably. We will continue to trade, on a smaller scale, as an important adjunct to our wholesale and retail marketing business.

The net result of changes in our business portfolio is NU's position as a smaller, more agile company. In recent years we added Yankee Energy and our competitive businesses, and sold Millstone, Seabrook and the fossil plants owned by CL&P and WMECO. Given our reduced size, we took the painful step in 2002 of reducing our administrative staff, eliminating the positions of 200 employees and 100 contractors. This should result in approximately $20 million in pre-tax cost savings in 2003.



NU Unsecured Debt Rating

I would like to thank several NU leaders who left our company in 2002. Raymond Golden, who chose to retire in December, was a Trustee for four years and provided valuable guidance to us. Bruce Kenyon, widely respected as the chief architect of the 1996-1999 turnaround at Millstone Station, retired as president of our Generation Group at the end of 2002. We are also indebted to four other NU executives who retired in 2002 – Jack Keane, Ted Feigenbaum, Gary Simon, and Keith Marvin – all of whom made lasting contributions to NU over their many years of dedicated service.

I would be remiss if I did not mention and thank all of the dedicated individuals in the NU family, past and present, who worked on our nuclear program from our industry-leading vision in the early days to the closing of the Seabrook sale to FPL. In the beginning and through the first decades, we were viewed as among the best nuclear operators in the world. This was followed by a period in the late 1980s and early- to mid-1990s when we faced our deepest challenge in the nuclear area. By the end of the 1990s and into the new millennium we regained our footing and closed our nuclear history as we had begun by being viewed as among the best nuclear operators in the world. The company owes a deep debt of gratitude to our state regulators and politicians, both state and federal, for helping us through these challenging times. We owe a specific gratitude to the Nuclear Regulatory Commission for helping us to become a better, more conservative operator and to create a safety-conscious work environment, which became the industry model. Lastly, we would like to thank the nuclear industry, with special thanks to the Nuclear Energy Institute, and Institute of Nuclear Power Operations, for their many contributions to our success. With the support of these groups and many more, we leave the nuclear industry as we began, with our heads held high.

Finally, my sincere appreciation is extended to our shareholders who continue to trust us with their investment and look to us to provide responsible, effectual leadership in a time of economic uncertainty and change. We are proud to earn your continued confidence as we leverage our industry expertise, proactively anticipate and meet our customers' energy needs, and address critical issues of energy security and reliability.

Sincerely,

Michael G. Morris

Michael G. Morris
Chairman, President and Chief Executive Officer

Bradley International Airport
Serving Hartford, Connecticut / Springfield, Massachusetts

Expanding to support the region's transportation infrastructure and access to global markets, Bradley International Airport called on Select Energy Services, Inc. to create an on-site cogeneration power plant. Select Energy Services designed, built and now manages the central energy plant, which produces reliable gas-fired power and thermal energy for a new terminal's electrical, heating and cooling needs. NU's Northeast Generation Services Company handles day-to-day operations. Yankee Gas both transports natural gas to serve the building and is working with the airport on alternate fuel vehicles for ground transportation. Key partners at Bradley International Airport are (left) James Adams, Deputy Commissioner of Connecticut's Department of Transportation, and Scott Frantz, Chairman of the Board of Bradley International Airport.

Delivering: Reliable Service

In 2002 NU opened a new state-of-the-art Emergency Operations Center at our Berlin, Connecticut, headquarters. Designed to ensure a coordinated, safe, efficient response to any emergency that might adversely affect our customers, the Center serves as a central command for disasters including major storms and power outages. NU has a long heritage and strong national reputation in emergency management and has offered the Center to other utilities as well as state and municipal officials.

Few things are as important to the communities we serve as reliable, reasonably priced energy to keep homes and businesses running and the economy moving forward. Our network of poles, wires and pipes provides a strong infrastructure for the safety, security and stability of the region.

To help CL&P's 87,500 small- to mid-size business customers – from "Mom and Pop" retail stores to small manufacturers – CL&P opened a new Business Solutions Center in Berlin, Connecticut. Our business solutions consultants provide a single point of contact on technical issues such as power quality, reliability and energy efficiency.

WMECO launched two new products in 2002 to enhance service reliability. For participating customers, our new Outage Notification Service provides the peace of mind that they and WMECO will be alerted automatically of a power outage. This service is especially helpful for physically challenged or medically dependent customers at home. Our new residential Surge Protection Service protects homes in two ways – the device blocks electric power surges from entering, with extra plug-in devices to provide a second level of protection for sensitive electronic equipment.

To keep pace with its growing customer base and replace old and outdated equipment, PSNH has invested more than $110 million in our transmission and distribution system. These reliability improvements are helping to serve PSNH customers such as Fidelity Investments. To meet Fidelity's exacting needs, PSNH improved power quality and reliability by reconfiguring the distribution system, which involved several substations in the Nashua area. Thanks to PSNH, Fidelity's customer service, bond trading, Internet and data center operations can run smoothly.

Yankee Gas delivered more energy options to homeowners and businesses across Connecticut, installing 12 miles of new natural gas pipeline. The choice of clean, reliable natural gas had never been an energy option for the town of East Lyme until Yankee Gas extended its distribution system through the town's business district. East Lyme First Selectman Wayne Fraser noted, "The expansion of natural gas into our commercial district will make the town more competitive, helping us attract potential new businesses and give existing businesses greater flexibility in their energy choices." The second year of Yankee's planned multi-year system expansion supported local economic development growth and the energy reliability needs of businesses in 11 communities, including three industrial parks.

In our competitive business group, Northeast Generation Services Company completed projects throughout New England to upgrade utility substations for increased energy security. A growing number of power generation and industrial customers also looked to us for a range of reliability services from plant modernization to fuel cell operations.

Efficiency means a lot of things at Northeast Utilities. From efficient, cost-effective operations supporting our customers, to advancing our "energy efficiency ethic" helping customers save energy, money and the environment, we know efficiency.

In fact, employee teams are at work throughout NU examining and enhancing the efficiency of our operations. CL&P implemented a Work Management System that is standardizing work functions across work centers. Yankee Gas has one of the best customer response records in the natural gas industry – in 2002, meeting or exceeding all customer service and satisfaction measures in a new Service Quality Plan, thanks to more streamlined processes. WMECO employees developed a more efficient way to recover costs associated with third-party damage to our equipment, such as when a car strikes a utility pole. And at PSNH's Merrimack generating station, an employee team was able to complete a planned outage safely, ahead of schedule, saving some $900,000 in the process.

NU is a leader in advancing efficiency for customers, too. We promote the efficient use of energy while caring for the environment and promoting economic development. Hundreds of thousands of customers across Connecticut, western Massachusetts and New Hampshire have participated in our programs that help large and small businesses, homeowners and renters, and state and local governments save energy, money and the environment.

In New York, Select Energy is the U.S. General Services Administration's electricity supplier of choice. Their multi-year agreement includes wind power for the Binghamton Federal Building and the Alexander Pirnie Federal Building in Utica, making them the first federal facilities in the country to be powered entirely by wind-generated electricity.

From improving lighting in school classrooms to create a better environment for learning while saving Connecticut towns energy and money, to offering a PRIME program – Process Reengineering for Increased Manufacturing Efficiency – for commercial customers such as the Simmons Company mattress makers in WMECO's area, to our competitive businesses supporting facilities like the Portsmouth Naval Shipyard in Kittery, Maine, with upgrades to the energy efficiency of their military facilities, energy efficiency is one of the best ways we can add value for our customers.

PSNH's New Central Warehouse, Bow, New Hampshire

Located on 17 acres, PSNH's new 32,200-square-foot facility features a state-of-the-art warehouse, testing facility, loading area, offices and outdoor storage for electrical equipment, transformers and wire. PSNH area work locations across the state are efficiently served by warehouse employees (left) William Tyler and Roger Rhealt.

Delivering: Efficiency

NU-Sponsored Habitat Home, Windsor, Connecticut

Combining the energy of our employee volunteers, sponsorship from Northeast Utilities, our valuable guidance on energy efficiency, and a strong partnership with Hartford Area Habitat for Humanity, we were able to help Tiffany Pettigrew and her son, Jordan, become first-time homeowners in the spring of 2002. Their Windsor, Connecticut, home meets federal ENERGY STAR® standards to save electricity, gas and money every day, all year. Thanks to a partnership with NU, Hartford Area Habitat for Humanity is now constructing all their homes to these valuable energy efficiency standards.

Delivering: Social Responsibility

Perhaps never before have consumers and investors judged corporations so intently on their social responsibility. It is vital to the success and profitability of any company.

The principle of corporate social responsibility has been part of the fabric of Northeast Utilities for more than 100 years. We are committed to giving back to the communities in which we live and work. Education, job training, economic and community development, social and health services, environmental stewardship and civic responsibility – these are all areas in which people count on NU to be a good neighbor. We deliver on that commitment, and more.

In 2002, the Massachusetts Audubon Society, the oldest independent state Audubon Society in the nation and the largest environmental organization in New England, received a grant from the NU Foundation to support a two-year study to determine what influences the reproduction success of shrubland nesting birds in power line rights of way. These birds are in decline throughout the New England area. The Massachusetts Audubon and NU will use the data from the study to safeguard important habitats.

NU's Northeast Generation Company and Northeast Generation Services Company were recognized for Outstanding River Stewardship in 2002. Our environmentally suitable solutions stabilized erosion and improved wildlife habitat in areas adjacent to our power facilities along the Connecticut River.

Committed to fostering respect for diversity in the workplace, Yankee Gas and CL&P were major supporters of a Connecticut Public Television original documentary on diversity in the state. A compelling exploration of the racial, religious and cultural differences that divide as well as unify us, "Understanding the Divide" follows residents' personal struggles, successes, barriers and triumphs. Thousands of television viewers will see diversity in a new light thanks to this riveting presentation.

To both build team spirit within the company and support U.S. troops abroad at holiday time, NU's Transmission Business employees organized and shipped more than 1,200 pounds of food, hygiene aids and entertainment items to U.S. troops stationed in Afghanistan.

We also contribute our expertise and financial support to a number of education initiatives across NU. For example, PSNH supports the Latino Initiative aimed at attracting Hispanic students to the university system. And CL&P is actively involved in the Hartford Construction Jobs Initiative Program, a jobs training program focusing on pre-apprentice training for individuals in the Hartford area. This program received the National Workforce Excellence Award in 2002.

Regulated Businesses

The Connecticut Light and Power Company

Business and Services

Delivering *Energy for a Changing World*, CL&P has been a part of everyday life in Connecticut for more than 100 years by providing safe and reliable electric service to more than 1.1 million customers' homes, neighborhoods and businesses.

Markets

CL&P's 2,300 employees are committed to anticipating and meeting customer needs and ensuring the reliability of nearly 21,000 miles of distribution lines serving 149 Connecticut cities and towns. An active member in the communities it serves, CL&P offers programs in energy efficiency, economic development and environmental education.

Public Service of New Hampshire

Business and Services

PSNH is the largest electric utility in New Hampshire, providing safe, dependable and reliable electric service to more than 447,000 homes and businesses.

Markets

Serving 202 communities, PSNH provides electric service to more than 75 percent of the Granite State and offers a number of programs and services to help customers save money and energy every month. With 14 generation facilities, PSNH has an ample and diverse supply of energy that is part of New Hampshire's continued economic growth.

Transmission Services

Business and Services

NU continues to distinguish itself as an industry leader in its pursuit of high-voltage electric transmission infrastructure solutions for our customers. The transmission business will invest nearly $1 billion over the next five years to provide customers with access to a reliable, diverse and competitively priced electricity supply.

Markets

To support regional growth and vitality and address the region's need for reliable service, NU is working to strengthen the existing transmission system. The successful completion of our planned projects will deliver more energy choices, improved reliability and competitively priced energy to nearly five million customers across New England.

Western Massachusetts Electric Company

Business and Services

WMECO distributes safe, dependable and reliable energy and innovative energy solutions to meet the needs of approximately 200,000 customers throughout western Massachusetts.

Markets

Serving 59 communities, WMECO is western Massachusetts' largest electric distribution company and a partner in each community it serves through its economic and community development assistance, environmental stewardship and community involvement. Providing a unique and innovative array of residential, municipal, commercial, and industrial programs, WMECO assists customers in managing their costs, enhancing their quality of life and maintaining a competitive economic climate.

Yankee Energy System, Inc.

Business and Services

Yankee Energy System, Inc. includes Yankee Gas Services Company (Yankee Gas), Connecticut's largest natural gas distribution company, and Yankee Energy Financial Services Company (Yankee Financial), providing a full range of residential and commercial energy equipment financing options.

Markets

Yankee Energy, through its principal operating subsidiary, Yankee Gas, delivers natural gas and related products and services to 191,000 residential, commercial and industrial customers in 70 Connecticut cities and towns. Yankee Financial offers residential and business customers financing options through its Hometown Energy Loan Program and Energy Key commercial financing program.

Competitive Businesses

NU Enterprises, Inc. (NUEI) is the wholly-owned subsidiary holding company of our competitive energy businesses:

Select Energy, Inc.

Business and Services

Our wholesale business line markets power to standard offer and default service providers, municipally-owned utilities, aggregators and other retail electric suppliers. We also provide full-service retail electric and natural gas supply to large commercial and industrial customers.

Markets

Primarily the 11 northeastern states from Maine to Maryland.

Select Energy Services, Inc.

Business and Services

From engineering consulting to plant operation services, Select Energy Services specializes in turn-key energy and water systems for government, industrial, commercial and institutional facilities.

Markets

Primarily the 11 northeastern states with federal installations throughout the U.S. and internationally.

Northeast Generation Services Company

Business and Services

NGS provides power plant management and operations, engineering and design, project management, and construction and maintenance services to industrial and power generation facilities.

Markets

Northeast and mid-Atlantic states.

Northeast Generation Company and Holyoke Water Power Company

Business and Services

NGC and HWP, a direct subsidiary of NU, own a total of 1,438 MW of generation capacity. NGC assets include the 1,080-MW Northfield Mountain pumped storage facility, 190 MW of conventional hydroelectric facilities and a 21-MW peaking facility. HWP owns the 147-MW coal-fired Mt. Tom facility.

Markets

The New England power pool.

Management's Discussion and Analysis

Financial Condition

Overview

Consolidated: Northeast Utilities and subsidiaries (NU or the company) reported 2002 earnings of $152.1 million, or $1.18 per share compared with earnings of $243.5 million, or $1.79 per share in 2001 and a loss of $28.6 million, or $0.20 per share in 2000. In 2002 and 2001, the divestiture of nuclear generation assets in which NU had a significant ownership interest had a material positive impact on the company's financial results. All per share amounts are reported on a fully diluted basis.

During 2002, NU recorded after-tax gains totaling $24.5 million, or $0.19 per share, associated with the sale of its ownership interest in the Seabrook nuclear units (Seabrook) and the elimination of reserves associated with its ownership share of Seabrook assets. During 2001, NU recorded a net after-tax gain of $115.6 million, or $0.85 per share, associated with the sale of its ownership interest in the Millstone nuclear units (Millstone).

During 2002 and 2001, NU recorded various other charges. During 2002, NU recorded an after-tax loss of $11 million, or $0.09 per share, primarily associated with the write-down of investments in NEON Communications, Inc. (NEON) and Acumentrics Corporation (Acumentrics). During 2001, NU recorded an after-tax loss of $22.4 million, or $0.17 per share, as a result of the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and an after-tax loss of $35.4 million, or $0.26 per share, associated with an agreement with two financial institutions to repurchase NU common shares. Excluding the aforementioned nuclear generation asset divestitures and other charges, NU earned $138.6 million in 2002, compared with $185.7 million in 2001.

NU's revenues for 2002 decreased to $5.2 billion from revenues of $6 billion for 2001. The decrease in revenues is due to lower competitive energy subsidiary revenues and lower regulated subsidiary revenues. The decrease in the competitive energy subsidiaries' revenues is primarily due to lower wholesale marketing revenues from Select Energy, Inc. and subsidiary (Select Energy) full requirements contracts, primarily due to lower energy prices. The decrease in the regulated subsidiaries' revenues is due to lower regulated wholesale and retail revenues. Regulated wholesale revenues decreased primarily due to lower sales associated with purchase-power contracts, lower wholesale sales in New Hampshire and the 2001 revenue associated with the sale of Millstone output. The decrease in regulated retail revenue is primarily related to a rate decrease at Public Service Company of New Hampshire (PSNH), a decrease of the Western Massachusetts Electric Company (WMECO) standard offer rate and a decrease in Yankee Gas Services Company (Yankee Gas) revenues associated with lower gas sales and lower 2002 rates.

NU's earnings per share (EPS) continued to benefit from the company's ongoing share repurchase program. During 2002 NU repurchased 3.7 million shares at an average price of $15.78 in addition to the 14.3 million shares repurchased in 2001 at an average price of $20.34. The company had 127.6 million shares outstanding at December 31, 2002, compared to 130.1 million outstanding shares on December 31, 2001.

In January and February 2003, NU repurchased an additional 1.1 million shares at an average price of $14.44 and can repurchase an additional 6 million shares through June 30, 2003, under an existing resolution approved by the NU Board of Trustees.

The share repurchase program is part of a fundamental restructuring of NU's earnings base that has taken place since 1999. Over the past four years, NU's regulated subsidiaries have sold nearly 5,000 megawatts (MW) of New England electric generation to unaffiliated companies for approximately $2 billion and have securitized more than $2 billion of stranded costs. The proceeds from those sales and securitizations have allowed NU to reduce its combined level of debt and preferred stock by nearly 50 percent since the end of 1997. However, the reduction of NU's generation plant and lower level of regulatory assets also has significantly reduced the earnings power of NU's regulated electric businesses.

NU has partially offset that lower regulated earnings base by acquiring Yankee Energy System, Inc. (Yankee) in 2000, lowering debt and preferred stock levels, repurchasing common shares, making needed investments in its regulated electric distribution and transmission infrastructure, and expanding into the competitive energy business in the Northeast United States. To date, the success of those efforts has been mixed. The retirement of debt has significantly improved NU's consolidated balance sheets, and NU's credit ratings are higher than they have been in at least three decades. Share repurchases have been accretive, and Yankee has been well integrated into NU. NU is in the early stages of its regulated distribution and transmission investment program. As this program progresses, the regulated earnings base will increase over the next several years. However, NU's investment of more than $500 million of equity into its competitive energy businesses has not yet produced the long-term return on investment management requires. A key focus of management in 2003 will be to improve competitive business performance significantly.

Regulated Utilities: Performance among NU's five regulated subsidiaries varied in 2002 with three posting lower results than in 2001 and two posting stronger results. Net income before the payment of preferred dividends totaled $85.6 million at The Connecticut Light and Power Company (CL&P), compared with $109.8 million in 2001. The lower 2002 net income was largely attributable to an after-tax gain of $17.7 million CL&P recorded in 2001 associated with the sale of Millstone. Net income before the payment of preferred dividends at PSNH totaled $62.9 million in 2002, compared with $81.8 million in 2001. The lower 2002 net income was largely due to an after-tax gain of $15.5 million PSNH recorded in 2001 as a result of the sale of PSNH's share of the Millstone 3 nuclear unit. Net income at Yankee totaled $15.9 million in 2002, compared with $25.8 million in 2001. The lower 2002 net income was primarily due to the mild first quarter of 2002, usually Yankee Gas' most profitable period of the year, and to the after-tax recognition of approximately $10 million in 2001 related to a favorable property tax settlement.

WMECO recorded net income before the payment of preferred dividends of $37.7 million in 2002, compared with $15 million in 2001. The improved 2002 results were largely due to the recognition of $13 million in investment tax credits and the elimination of $9 million of reserves, both in 2002, as a result of regulatory decisions. North Atlantic Energy Corporation (NAEC) earned $26.3 million in 2002, compared with $4.2 million in 2001. The improved 2002 results were largely due to the elimination of a Seabrook-related reserve during 2002. On November 1, 2002, NAEC sold its 35.98 percent share of Seabrook. Subsequently, a portion of NAEC's equity was repaid to NU. NAEC's operations will not have a material impact on NU's consolidated financial results in 2003 or thereafter.

Competitive Energy Subsidiaries: The decline in NU's 2002 earnings was primarily a result of disappointing results at NU's competitive energy subsidiaries. In 2002, those businesses lost $54.1 million, or $0.42 per share, compared with earnings prior to the charge associated with the adoption of SFAS No. 133 of $5 million, or $0.04 per share, in 2001 and a contribution towards NU's consolidated earnings of $13.6 million, or $0.10 per share, in 2000. Select Energy's wholesale marketing business was essentially break-even in 2002, following a loss of approximately $13 million in 2001. Those results include the performance of Northeast Generation Company (NGC) and Holyoke Water Power Company (HWP). Select Energy's retail marketing business experienced weaker performance during 2002, with losses of approximately $28 million, compared with 2001 losses of approximately $8 million, excluding the loss associated with the adoption of SFAS No. 133, as amended. Select Energy's trading business also lost approximately $24 million in 2002 compared with earnings of $19 million in 2001. NU's energy services businesses, including Northeast Generation Services Company (NGS) and Select Energy Services, Inc. (SESI), were essentially break-even in 2002. SESI earned $3 million while NGS lost $3.2 million. In 2001, SESI earned $2.4 million and NGS earned $4.6 million. In 2002, NU Enterprises, Inc. (NUEI) and the energy services subsidiaries of Yankee lost approximately $2 million.

Future Outlook

Consolidated: NU estimates that it will earn between $1.10 per share and $1.30 per share in 2003.

Regulated Utilities: The earnings range of between $1.10 and $1.30 per share includes earnings of between $1.05 per share and $1.15 per share at the regulated businesses, compared with aggregate earnings of $1.72 per share at the regulated businesses in 2002. The primary reason for the earnings reduction at the regulated businesses in 2003 is the sale of Seabrook in 2002 and the resulting elimination of operating earnings at NAEC in 2003, the recording of $13 million of tax credits at WMECO in 2002, and a significant reduction in the projected level of pension income in 2003 and forward.

NU recorded $73.4 million of pre-tax pension income in 2002, approximately 30 percent of which was capitalized and reflected as a reduction to the cost of capital expenditures with the remainder being recognized in the consolidated statements of income as reductions to operating expenses. In 2003, as a result of continued poor performance in the equity markets, NU is projecting the total level of pre-tax pension income to decline to approximately $31 million, with a similar percentage being reflected as a reduction to the cost of capital expenditures. Pension income is annually adjusted during the second quarter based upon updated actuarial valuations, and the 2003 estimate may be modified.

The lower pre-tax pension income will be partially offset by a reduction in workforce at NU. In 2002, NU reduced its workforce by approximately 200 employees and commenced an effort to reduce the number of non-employee vendors it currently employs by approximately 50 percent. Together these efforts are expected to reduce costs by approximately $20 million annually on a pre-tax basis. Management believes that most of the cost of the workforce reduction, which was approximately $13 million, is recoverable from ratepayers as a stranded cost related to industry restructuring.

Competitive Energy Subsidiaries: NU projects that the financial performance of its competitive energy subsidiaries will improve in 2003 and that those subsidiaries will earn between $0.15 per share and $0.25 per share. NU believes that its wholesale marketing business, including NGC and HWP, will be profitable. Management also projects that its retail marketing business will break-even and its trading business will be modestly profitable in 2003, and that financial performance at its energy services businesses, NGS and SESI, will also be profitable in the aggregate.

NU also projects that parent company expenses, primarily related to three long-term debt issuances, will cost the company approximately $0.10 per share in 2003.

Liquidity

Consolidated: The year 2002 represented the final year of a four-year process of selling most of the regulated generation assets owned by NU. The sale of those assets and the sale of more than $2.1 billion of rate reduction bonds and certificates to securitize stranded costs resulted in the inflow of more than $4.3 billion over a 40-month period ending with the sale of NU's 40.04 percent ownership of Seabrook, 35.98 percent by NAEC and 4.06 percent by CL&P, on November 1, 2002. NU received approximately $367 million of total cash proceeds from the sale of Seabrook and another approximately $17 million from Baycorp Holdings, Ltd. as a result of the sale of its 15 percent 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 will be used to pay approximately $95 million in taxes. The remaining proceeds received by NAEC were refunded to PSNH through the Seabrook Power Contracts. As a result, NU remained at a high level of liquidity during 2002, despite rising capital investments in its regulated electric and gas segments. At December 31, 2002, NU had $2.4 billion of long-term and short-term debt and capital lease obligations outstanding, excluding rate reduction bonds, compared with $2.7 billion of debt and capital lease obligations outstanding at December 31, 2001.

Aside from the rate reduction bonds outstanding, NU has a very modest level of sinking fund payments and debt maturities due between 2003 and 2011, averaging approximately $38 million annually and totaling $56.9 million in 2003. Most of the debt that must be repaid during that period of time was issued by NU parent, NGC and Yankee Gas. No CL&P, PSNH or WMECO debt issues mature during that nine-year period. Because of NU's current high level of liquidity and modest level of debt maturities in the coming years, management does not expect to experience the severe credit and refinancing issues that many other energy industry companies have faced in the past two years.

NU's net cash flows provided by operating activities increased to $612.6 million in 2002, compared with $328.6 million in 2001 and $599.8 million in 2000. Cash flows provided by operating activities increased primarily due to increases in working capital items, primarily accrued taxes, offset by a reduction in net income, primarily due to the gain associated with the sale of Millstone in 2001. Accrued taxes increased because the taxes related to the sale of Seabrook will not be paid until March of 2003. The decrease in cash flows provided by operating activities in 2001 related primarily to increases in receivables and unbilled revenues associated with the sales growth of NU's competitive energy subsidiaries.

There was a lower level of investing and financing activities in 2002 as compared to 2001, primarily due to the issuance of long-term debt, issuance of rate reduction bonds and certificates and the buyout and buydown of independent power producer contracts in 2001. The level of common dividends totaled $67.8 million in 2002, compared with $60.9 million in 2001 and $57.4 million in 2000. The increase resulted from NU paying a $0.125 per share quarterly common dividend in the first two quarters of 2002 and a $0.1375 per share quarterly dividend in the last two quarters of 2002. The level of quarterly common dividend payments during 2001 was $0.10 per share during the first two quarters of 2001 and $0.125 during the last two quarters of 2001. The increase in the common dividend was partially offset by a decrease in outstanding shares.

Management expects to continue to increase the dividend level, subject to NU's ability to meet earnings targets and the judgment of its Board of Trustees at the time the dividends are declared. On January 13, 2003, the NU Board of Trustees approved the payment of a $0.1375 per share dividend payable on March 31, 2003, to shareholders of record at March 1, 2003.

Despite the increase in the common dividend, NU parent ended the year with a high level of liquidity, all of which was loaned to subsidiaries through the NU Money Pool or through direct loans. The parent company's cash levels increased as a result of continued return of equity capital from its regulated subsidiaries, as well as their payment of common dividends to the parent. In 2002, CL&P paid $60.1 million of dividends to NU parent and returned another $100 million of equity capital through share repurchases. PSNH paid $45 million of dividends in 2002, in addition to the return of another $37 million of equity capital. As a result of the Seabrook sale, NAEC paid $5 million of dividends and returned another $35 million of equity capital to NU. WMECO paid $16 million of dividends and returned $14 million of equity capital to NU. The parent company also received another $10 million in dividends from NGC through its parent company, NUEI along with $3 million directly from NUEI. The parent company's liquidity is reinforced by no debt maturities, a modest common dividend, and minimal sinking fund payments of $23 million in 2003 and $24 million in 2004. Equity capital transactions between NU parent and its subsidiaries are eliminated in consolidation.

Regulated Utilities: NU's regulated utilities had a modest level of financings in 2002. In January 2002, PSNH issued an additional $50 million in rate reduction bonds and used the proceeds to repay short-term debt that was incurred to buyout a purchased-power contract in December 2001. In April 2002, NU issued $263 million of 7.25 percent senior unsecured notes due on April 1, 2012. Proceeds from the refinancing were used to redeem a similar amount of variable rate notes that were issued on February 28, 2001 related to the Yankee merger.

In November 2002, the regulated utilities renewed their $300 million credit line, under terms similar to the arrangement that expired in November 2002. A previous credit line had provided up to $350 million for the regulated companies. There were $7 million in borrowings on this credit line at December 31, 2002.

In addition to its revolving credit arrangement, CL&P can access up to $100 million by selling certain of its accounts receivable. At December 31, 2002, CL&P had $40 million outstanding under this arrangement. The current accounts receivable arrangement is expected to be renewed in July 2003.

Rate reduction bonds are included on the consolidated balance sheets of NU, CL&P, PSNH and WMECO, even though the debt is nonrecourse to these companies. At December 31, 2002, these companies had a total of $1.9 billion in rate reduction bonds outstanding, compared with $2 billion outstanding at December 31, 2001. All outstanding rate reduction bonds of CL&P are scheduled to amortize by December 30, 2010, with those of PSNH scheduled to fully amortize by May 1, 2013, and those of WMECO scheduled to fully amortize by June 1, 2013. Interest on the rate reduction bonds totaled $115.8 million in 2002, compared with $87.6 million in 2001. Amortization of the rate reduction bonds totaled $169 million in 2002, compared with $100 million in 2001. CL&P, PSNH and WMECO fully recovered the amortization and interest payments from customers in 2002 and the bonds had no impact on net income. Moreover, because the debt is nonrecourse to these companies, the three rating agencies that rate their debt and preferred stock securities do not include the revenues, expenses, or outstanding securities related to the rate reduction bonds in establishing the credit ratings of NU or its subsidiaries.

CL&P and Yankee Gas have embarked upon significant upgrade programs within their service territories. Over the past five years, CL&P has increased its annual level of investment in electric utility plant by approximately 50 percent. Much of the additional investment has been devoted to improving the reliability of CL&P's electric distribution system. Over the next several years, CL&P has proposed a significant expansion of its 345,000 volt electric transmission system into southwestern Connecticut at a cost that is likely to exceed $500 million. If Connecticut regulators approve the expansion, CL&P's construction expenditures are projected to exceed $350 million annually from 2004 through 2007. Such a program would exceed CL&P's projections for internally generated operating cash flows, and therefore, CL&P expects to access the capital markets for financing during this period. In 2003, CL&P is expected to generate enough cash internally to fund most, if not all, of its capital needs.

Yankee Gas, pursuant to the recommendations of the Connecticut Department of Public Utility Control (DPUC) when it approved NU's acquisition of Yankee, has embarked upon a significant expansion within its service territory. Yankee has not paid a common dividend since it merged with NU in 2000, using its internally generated cash to fund its expansion program. This expansion will likely require Yankee Gas to issue new debt. Although Yankee Gas' debt is not currently rated, management believes Yankee Gas would be able to attract capital at a reasonable cost due to its regulated activities and strong balance sheet. At December 31, 2002, Yankee Gas had $215.4 million of common equity, excluding common equity related to goodwill, and $151.4 million of long-term debt.

PSNH funded its capital expenditures through internally generated cash flows and through proceeds returned from NAEC as a result of the sale of Seabrook. PSNH returned $37 million of equity capital to NU in 2002. PSNH's capital expenditures are expected to total $116.3 million in 2003 and remain largely funded through internally generated cash flows.

WMECO has applied to the Massachusetts Department of Telecommunications and Energy (DTE) to refinance approximately $100 million of short-term and spent nuclear fuel obligations. A decision is expected in the first half of 2003. CL&P also is considering refinancing approximately $200 million of spent nuclear fuel obligations in 2003.

Competitive Energy Subsidiaries: In November 2002, NU renewed its $350 million credit line for the competitive energy subsidiaries, under terms similar to the arrangement that expired in November 2002. A previous credit line had provided up to $300 million for the competitive energy subsidiaries. There were $49 million in borrowings on this credit line at December 31, 2002, and Select Energy had approximately $6.7 million in letters of credit outstanding to provide credit assurance for wholesale power transactions.

NU's competitive businesses have minimal capital expenditures. NGC's capital expenditures totaled $16.4 million while HWP's totaled $1 million and other capital expenditures totaled $5.8 million in 2002. In July 2002, NU's competitive energy subsidiaries acquired certain assets and assumed certain liabilities of Woods Electrical Co., Inc. (Woods Electrical), an electrical services company, and Woods Network Services, Inc. (Woods Network), a network products and services company, for an aggregate adjusted purchase price of $16.3 million (collectively Woods). NU made no other business acquisitions in 2002.

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' October 13, 1999 Agreement and Plan of Merger, as amended and restated as of January 11, 2000 (the Merger Agreement). On March 12, 2001, NU filed suit against Con Edison in the United States District Court for the Southern District of New York (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 seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation. Con Edison has claimed that it is entitled to recover a portion of the merger synergy savings estimated to have a net present value of in excess of $700 million. NU disputes both Con Edison's entitlement to any damages as well as its method of computing its alleged damages.

The companies have completed discovery in the litigation. Motions for summary judgment were argued before the District Court on February 4, 2003. No trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU.

For further information regarding this litigation, see NU's 2002 report on Form 10-K, Item 3, "Legal Proceedings."

Implementation of Standard Market Design

On March 1, 2003, the New England independent system operator (ISO) implemented a new Standard Market Design (SMD). As part of this effort, locational marginal pricing (LMP) will be utilized to assign value and causation to transmission congestion. Transmission congestion costs will be assigned to the load zone in which the congestion occurs. Those costs are now spread across virtually all New England electric customers. In addition, the implementation of SMD will impact wholesale energy contracts with respect to the energy delivery points contained in those contracts.

Regulated Utilities: Connecticut has been designated a single load zone. Due to the transmission constraints and inadequate generation, Connecticut could experience significant additional congestion costs under SMD. The New England ISO estimates that the costs of transmission congestion for 2003 in New England under SMD will range between $50 million and $300 million. The New England ISO estimates that the majority of this congestion and its costs will be in Connecticut, where approximately 80 percent are expected to be paid by CL&P beginning on March 1, 2003. CL&P believes that under the terms of its standard offer service contracts with its standard offer suppliers these costs are its responsibility. The contracts with the standard offer suppliers expire on December 31, 2003. In addition, the determination of the energy delivery points associated with the standard offer service contracts under SMD could also produce significant costs for CL&P that management cannot determine at this time.

Another factor affecting the level of congestion costs is the designation of certain generating units by the New England ISO as units needed for system reliability. Some of the companies owning these units have applied to the Federal Energy Regulatory Commission (FERC) for "reliability must run" (RMR) treatment. RMR treatment allows these units to receive cost of service-based payments that recognize their reliability value. Prior to March 1, 2003, all RMR costs were spread across New England with all utilities being billed by the New England ISO based upon their share of New England's load. NU's regulated electric utilities were responsible for approximately 25 percent of these costs. Effective with the March 1, 2003 implementation of SMD by the New England ISO, RMR costs will be allocated to the load zone in which the RMR unit is located. At present, the only load zone that will experience a cost increase in which a NU regulated electric company operates is Connecticut. With respect to the Connecticut load zone, there are two generating units operating under a RMR contract with an additional contract pending before FERC. These contracts are for one year terms, and one contract contains an extension option. On a combined basis, these two RMR contracts will result in an annual cost of approximately $45 million to the Connecticut load zone. CL&P accounts for approximately 80 percent of the Connecticut load zone, and would be responsible for approximately $36 million of this cost. In the near future, it is probable that there will be significant new requests for RMR treatment in Connecticut which, if approved by FERC, would add significant additional costs to the total cost of energy in Connecticut. However, generating units operating under RMR contracts could potentially mitigate the overall level of congestion costs.

These unavoidable congestion and RMR costs are part of the prudent cost of providing regulated electric service in Connecticut. A DPUC regulatory proceeding is expected to be initiated soon to determine the appropriate recovery mechanism for these costs. If these costs are incurred before the final recovery mechanism is established by the DPUC, CL&P expects to record a regulatory asset for those costs incurred. See Critical Accounting Policies and Estimates – Regulatory Accounting and Assets included in management's discussion and analysis for further information.

Competitive Energy Subsidiaries: The implementation of SMD in New England will create challenges and opportunities for Select Energy. The impact of SMD on its wholesale marketing business could be significant. The determination of the energy delivery points in many wholesale marketing contracts and the location of sources of supply could have a significant effect. As more information regarding the timing and impact of SMD becomes available, there could be additional adverse effects that management cannot determine at this time.

Competitive Energy Subsidiaries

Subsidiaries: NU's competitive energy subsidiaries include HWP and NUEI, which is the parent company of Select Energy and its subsidiary Select Energy New York, Inc. (SENY), NGC, SESI, and NGS. Select Energy engages in wholesale and retail energy marketing activities and energy trading activities.

NU's competitive energy subsidiaries own 1,438 MW of generation capacity, consisting of 1,291 MW at NGC and 147 MW at HWP, which are used to support Select Energy's wholesale marketing business.

SESI performs energy management services for large industrial, commercial and institutional facilities, including the United States Department of Defense, and engages in energy related construction services. NGS operates and maintains NGC's and HWP's generation assets and provides third-party electrical, mechanical, and engineering contracting services.

Outlook: NU is taking a number of steps to return the competitive energy businesses to profitability in 2003 from the loss of $54.1 million in 2002. NU has acquired additional energy services businesses and expects that after essentially break-even earnings in 2002, they will be profitable in 2003.

Select Energy engages in energy trading activities primarily for price discovery and risk management purposes. Select Energy has considerably reduced its speculative trading activities and the amount of capital at risk in the trading operation to a daily average of approximately $0.4 million from up to $6 million in early 2002, and projects that the after-tax loss of approximately $24 million in 2002 will turn into modest profits in 2003. The 2002 results were negatively impacted by an increase in natural gas prices during March and April 2002.

Significant contributing factors to the 2002 loss in the retail marketing business were unprofitable energy contracts and unusually mild weather which significantly reduced natural gas sales. Many of the unprofitable contracts expired in 2002. Select Energy plans to size the retail marketing organization to fit the expected level of business and expects to better manage volumetric risk, particularly in the winter heating months. As a result, management expects to break-even in the retail marketing business in 2003, compared with a loss of approximately $28 million in 2002. To achieve this result in 2003, Select Energy must obtain new retail business and successfully manage its portfolio of retail contracts.

In the wholesale marketing business, Select Energy, including NGC and HWP, expects to be profitable in 2003, compared with essentially break-even performance in 2002. Select Energy expects significant improvement to come from improved results on its contract with CL&P, improved management of power supply contracts, and a return to normal river conditions around NGC's conventional hydroelectric plants. Select Energy expects the CL&P contract to be between breakeven and a loss of $10 million in 2003 compared to a loss of $47 million in 2002. Near drought conditions in New England, particularly in the first three quarters of 2002, lowered pre-tax earnings by approximately $6 million in 2002. This earnings projection also assumes that Select Energy will be successful in securing a significant amount of new business at acceptable margins and managing its wholesale marketing portfolio. NGC owns 1,291 MW of primarily hydroelectric generation capacity in Massachusetts and Connecticut and earned $30.4 million in 2002 and $42.3 million in 2001. HWP owns a 147 megawatt coal-fired plant in Holyoke, Massachusetts and lost $0.9 million in 2002 following earnings of $4.4 million in 2001. Select Energy has wholesale contracts with NGC and HWP to purchase all of the output of their generation assets. Accordingly, the results of these companies are included in Select Energy's wholesale marketing business.

CL&P's standard offer service purchases from Select Energy represented approximately $501 million of total competitive energy subsidiaries' revenues for 2002, compared with approximately $497 million for 2001. Other transactions between CL&P and Select Energy amounted to approximately $130 million in revenues for Select Energy for 2002, compared with approximately $151 million in 2001. These amounts are eliminated in consolidation.

Additionally, WMECO's purchases from Select Energy represented approximately $14 million and $4 million of total competitive energy subsidiaries' revenues in 2002 and 2001, respectively.

In 2002, the competitive energy subsidiaries 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 remaining years. In addition, the useful lives of certain software was revised and shortened to reflect a remaining life of 1.5 years. As a result of these studies, NU's operating expenses decreased by approximately $5.1 million in 2002 and are expected to decrease by approximately $9.4 million for 2003.

Competitive Energy Subsidiaries' Market and Other Risks

Overview: NU's competitive energy subsidiaries are exposed to certain market risks inherent in their business activities. Certain competitive energy subsidiaries, primarily Select Energy, enter into contracts of varying lengths of time to buy and sell energy commodities, including electricity, natural gas and oil. Market risk represents the risk of loss that may impact Select Energy's financial results due to adverse changes in commodity market prices.

Risk management within the competitive energy subsidiaries, including Select Energy, is organized by management to address the market, credit and operational exposures arising from the company's primary business segments including wholesale marketing, retail marketing and trading. The framework and degree to which these risks are managed and controlled is consistent with the limitations imposed by NU's Board of Trustees as established and communicated in NU's overall risk management policies and procedures. As a means to monitor and control compliance with these policies and procedures, NU has formed a Risk Oversight Council (ROC) to monitor competitive energy risk management processes independently from the businesses that create or manage these risks. The ROC ensures that the polices pertaining to these risks are followed and makes recommendations to the Board of Trustees regarding periodic adjustment to the metrics used in measuring and controlling portfolio risk while also confirming the methodologies employed by management to discern portfolio values.

Wholesale and Retail Marketing: A significant portion of Select Energy's wholesale marketing business is providing energy to full requirements customers, primarily regulated distribution companies. Under full requirements contract terms, Select Energy is required to provide the total energy requirement for the customers' load at all times. Wholesale and retail marketing transactions, including the full requirements contracts, are intended to be part of Select Energy's normal purchases and sales and are recognized on the accrual basis of accounting.

An important component of Select Energy's risk management strategy is focused on managing the volume and price risks of full requirements contracts. These risks include significant fluctuations in supply and demand due to numerous factors such as weather, plant availability, transmission congestion, and potentially volatile price fluctuations. Select Energy uses energy contracts to hedge these risks. While not classified as hedges for accounting purposes, these contracts, which are included in the wholesale and retail marketing portfolios and are subject to accrual accounting, are important to Select Energy's risk management. As discussed above, Select Energy's 2002 results were negatively impacted by weather patterns that resulted in contracted supply exceeding demand in the warmer than expected winter and purchasing supply during certain summer months at prices higher than those forecasted.

The competitive energy subsidiaries manage their portfolio of wholesale and retail marketing contracts and assets to maximize value while maintaining an acceptable level of risk. The lengths of contracts to buy and sell energy vary in duration from daily/hourly to several years. At any point in time, the wholesale and retail marketing portfolio may be long (purchases exceed sales) or short (sales exceed purchases). Portfolio and risk management disciplines with established policies and procedures are used to manage exposures to market risks. At forward market prices in effect at December 31, 2002, the wholesale marketing portfolio, which includes the CL&P standard offer service contract and other contracts that extend to 2013, had a positive fair value. This positive fair value indicates a positive impact on Select Energy's gross margin in the future. However, there is significant volatility in the energy commodities markets that will impact this position between now and when the contracts are settled. Portfolio volatility reflects fluctuations in value due to changes in energy prices in the region, new transactions entered into during the period and positions settling during the period. Accordingly, there can be no assurances that Select Energy will realize the gross margin corresponding to the present positive fair value on its wholesale marketing portfolio. The gross margin realized could be at a level that is not sufficient to cover Select Energy's other operating costs, including the cost of corporate overhead.

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 purchases for firm sales 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 retail supply 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, natural gas or oil. A derivative that effectively 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 other comprehensive income, which is a component of equity. 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 accumulated other comprehensive loss and the hedge and the forecasted transaction being hedged are in a loss position on a combined basis. At December 31, 2002, Select Energy had hedging derivative assets of $22.8 million and hedging derivative liabilities of $2 million. At December 31, 2001, Select Energy had hedging derivative assets of $2.9 million and hedging derivative liabilities of $60.7 million. The change from hedging derivative liabilities at December 31, 2001 to hedging derivative assets at December 31, 2002 resulted primarily from increased natural gas prices and the maturity or termination of hedge instruments existing at December 31, 2001.

Energy Trading: Energy trading transactions at Select Energy include financial transactions and physical delivery transactions for electricity, natural gas and oil in which Select Energy is attempting to profit from changes in market prices. Energy trading contracts are recorded at fair value, and changes in fair value impact earnings. For information regarding changes in accounting for energy trading transactions, see Note 1C, "New Accounting Standards," to the consolidated financial statements.

At December 31, 2002, Select Energy had trading derivative assets of $102.9 million and trading derivative liabilities of $61.9 million on a counterparty-by-counterparty basis, for a net positive position of $41 million on the entire trading portfolio. At December 31, 2001, Select Energy had trading derivative assets of $147.2 million and trading derivative liabilities of $90.8 million on a counterparty-by-counterparty basis, for a net positive position of $56.4 million on the entire trading portfolio. These amounts are combined with other derivatives and are included in derivative assets and derivative liabilities on the accompanying consolidated balance sheets. Information regarding the other derivatives is included in Note 3, "Derivative Instruments, Market Risk and Risk Management," to the consolidated financial statements.

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

Select Energy has policies and procedures requiring all trading positions to be marked-to-market at the end of each trading day. Controls are in place segregating responsibilities between 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, 2002 and 2001 below. 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; 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 quotes; and 3) prices based on models or other valuation methods primarily include forwards and options and other transactions for which specific quotes are not available. These transactions are modeled using recognized option pricing models. The option component of a forward electricity purchase contract had a fair value of $4.5 million at December 31, 2002, and is the only amount included in this method of determining fair value. The fair value of this contract component at December 31, 2001 was not material. Broker quotes for electricity are available through the year 2005, and models are generally used for the years 2006 and thereafter. Select Energy has procured sourcing for the contracts with maturities in excess of four years. Accordingly, the value of these contracts and the related power supply contracts do not need to be determined with a model. Broker quotes for natural gas are available through 2013. The decrease in the number of counterparties participating in the market for long-term energy contracts continues to impact Select Energy's ability to determine the estimated fair value of its long-term energy contracts.

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 based on models or other methods for longer-term contracts are less certain. Accordingly, there is a risk that contracts will not be realized at the amounts recorded.

As of and for the years ended December 31, 2002 and 2001, respectively, 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, 2002*			
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	$(1.2)	$ 0.1	$ —	$ (1.1)
Prices provided by external sources	2.8	20.2	14.6	37.6
Prices based on models or other valuation methods	—	4.5	—	4.5
Totals	$ 1.6	$24.8	$14.6	$41.0

(Millions of Dollars)	*Fair Value of Trading Contracts at December 31, 2001*			
Sources of Fair Value	*Maturity Less Than One Year*	*Maturity of One to Four Years*	*Maturity in Excess of Four Years*	*Total Fair Value*
Prices actively quoted	$ 6.5	$ 6.8	$ —	$13.3
Prices provided by external sources	6.5	15.8	20.8	43.1
Prices based on models or other valuation methods	—	—	—	—
Totals	$13.0	$22.6	$20.8	$56.4

As indicated in the tables, the fair value of energy trading contracts decreased $15.4 million from $56.4 million at December 31, 2001 to $41 million at December 31, 2002. This decrease, combined with the realized losses on positions taken and closed in 2002, is included in Select Energy's gross margin and, after it is tax affected, is reflected in the $24 million that Select Energy's trading business lost in 2002.

	Years Ended December 31,	
	2002	*2001*
(Millions of Dollars)	*Total Fair Value*	
Fair value of trading contracts outstanding at the beginning of the period	$56.4	$13.8
Acquisition of SENY	—	10.9
Contracts realized or otherwise settled during the period	(4.0)	(9.4)
Fair value of new contracts when entered into during the period	13.7	58.6
Changes in fair values attributable to changes in valuation techniques and assumptions	(39.9)	—
Changes in fair value of contracts	14.8	(17.5)
Fair value of trading contracts outstanding at the end of the period	$41.0	$56.4

During the first quarter of 2002, Select Energy terminated certain long-term energy contracts. Coincident with these contract terminations, new contracts were entered into with different terms and conditions. Select Energy also entered into several new contracts with existing counterparties. These new energy trading contracts are trading derivatives, and collectively they had a positive fair value of $13.7 million when entered into. In 2001, Select Energy entered into certain contracts with a fair value of $58.6 million when entered into.

Effective October 1, 2002, Select Energy adopted a consensus reached by the Emerging Issues Task Force (EITF) on October 25, 2002 in Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Adopting this consensus required management to conduct a thorough review of contracts in the trading portfolio to determine if there were any contracts in the trading portfolio that were not derivatives, as defined. Management determined that there were no nonderivative contracts in the energy trading portfolio, and as such, there was no cumulative effect of an accounting change as of October 1, 2002.

In connection with management's review of the contracts in the trading portfolio, the significant changes in the energy trading market and the change in the focus of the energy trading business, certain long-term derivative energy contracts that were included in the trading portfolio and valued at $33.9 million at November 30, 2002, were designated as normal purchases and sales. The impact of this designation is that the contracts were adjusted to fair value at November 30, 2002 and were not and will not be adjusted subsequently for changes in fair value. The $33.9 million carrying value of these contracts was reclassified from trading derivative assets to other long-term assets and will be amortized on a straight-line basis to fuel, purchased and net interchange power expense over the remaining terms of the contracts, some of which extend to 2011. This amount is included in changes in fair values attributable to changes in valuation techniques and assumptions.

The other negative $6 million reflected in changes in fair value attributable to changes in valuation techniques and assumptions relates to $12 million of contracts held by SENY at acquisition that were determined to be held for nontrading purposes by Select Energy. Accordingly the $12 million of contracts were removed from the trading portfolio. Long-term trading contracts with maturities in excess of four years and transmission congestion contracts were revalued during the year based on the availability of market information, which added $6 million to the value of the trading portfolio.

Late in the fourth quarter of 2002, Select Energy began to receive reliable market information concerning the impact of LMP in New England with the implementation of SMD, which is currently scheduled for March 1, 2003. Select Energy began to use this market information in its valuation of contracts in the trading portfolio. The impact of using this information was to reduce the portfolio value by $10.3 million, which is reflected as a negative amount in changes in fair value of contracts.

Nontrading: Nontrading derivative contracts are for delivery of energy related to the competitive energy subsidiaries' retail and wholesale marketing activities. At December 31, 2002, Select Energy had nontrading derivative assets of $2.9 million and no nontrading derivative liabilities. At December 31, 2001, Select Energy had no nontrading derivative assets or liabilities.

Changing Market: The breadth and depth of the market for energy trading and marketing products in Select Energy's market has been adversely affected by the withdrawal or financial weakening of a number of companies who have historically done significant amounts of business with Select Energy. In general, the market for such products has become shorter term in nature with less liquidity, and participants are more often unable to meet Select Energy's credit standards without providing cash or letter of credit support. Select Energy is being adversely affected by these factors, and there could be a continuing adverse impact on Select Energy's business prospects.

Changes are occurring in the administration of transmission systems in territories in which Select Energy does business. Regional transmission organizations (RTO) are being contemplated, and other changes are occurring within transmission regions. For example, the impact of the implementation of SMD on Select Energy's existing positions resulted in a decrease of $10.3 million in the fair value of Select Energy's trading portfolio. The impact of SMD on its wholesale marketing business is potentially more significant. The determination of the energy delivery points in many wholesale marketing contracts and the location of generation assets included in the wholesale marketing business could be significantly affected. As more information regarding the timing and impact of SMD becomes available, there could be additional adverse effects that management cannot determine at this time.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur as a result 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 conditions (including credit ratings), collateral requirements under certain circumstances (including cash in advance, letters of credit, 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 trading activities. 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, 2002, approximately 83 percent of Select Energy's counterparty credit exposure to wholesale marketing and trading counterparties is cash collateralized or rated BBB- or better. In excess of half of the remaining credit exposure is to unrated municipalities.

At December 31, 2002, two positions with counterparties collectively represented approximately 40 percent of the $102.9 million trading derivative assets. All other counterparties represented less than 10 percent of the trading derivative assets. Select Energy manages the credit risk of its trading portfolio in accordance with established credit risk management policies and procedures.

Select Energy Credit: A number of Select Energy's contracts 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. At NU's present investment grade ratings, Select Energy has not had to post any collateral based on credit downgrades. Were NU's unsecured ratings to decline two to three levels to sub-investment grade, Select Energy could, under its present contracts, be asked to provide approximately $140 million of collateral or letters of credit to various unaffiliated counterparties and approximately $80 million to several ISOs and unaffiliated local distribution companies, which NU, under present circumstances, would be able to provide from available sources. NU's ratings are currently stable, and management does not believe that at this time there is a significant risk of a ratings downgrade to sub-investment grade levels.

For further information regarding Select Energy's activities and risks see Note 3, "Derivative Instruments, Market Risk and Risk Management," and Note 11, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

Business Development and Capital Expenditures

Consolidated: NU anticipates that it will continue to increase its level of capital expenditures at its regulated subsidiaries to meet customers' increasing needs for additional and more reliable energy supplies. Investments in regulated utility plant, excluding nuclear fuel, totaled $468.8 million in 2002, compared with $428.3 million in 2001 and $345.6 million in 2000. NU expects that level to reach $640.2 million in 2003 and may be as high as $650 million in 2004, if CL&P's plans to expand its 345,000 volt transmission system are approved.

Regulated Utilities: CL&P's capital expenditures, excluding nuclear fuel, totaled $242.3 million in 2002, compared with $237.4 million in 2001 and $208.2 million in 2000. CL&P expects capital expenditures to increase to $326.9 million in 2003. CL&P spent $141.2 million related to its overhead and underground electric distribution system in 2002 and expects to spend a similar amount in 2003. CL&P spent $35.6 million to upgrade its transmission system in 2002, and expects its transmission capital expenditures to increase to $95 million in 2003, if its current construction plans receive regulatory approval. CL&P also spent $20 million on new meters and customer services, and $17 million on substations in 2002.

In 2001, CL&P announced plans for three transmission projects. In September 2002, the Connecticut Siting Council (CSC) approved the first project, a plan to replace an undersea electric transmission line between Norwalk, Connecticut and Northport – Long Island, New York, at an estimated cost of $80 million. CL&P owns 50 percent of the line with the

Long Island Power Authority also owning 50 percent. The project still requires federal and New York state approvals. Given the approval process and the uncertainty created by the recent damage to the existing transmission line, the expected in-service date is currently under evaluation. At December 31, 2002, CL&P has capitalized approximately $4.8 million related to this project.

In early 2003, the CSC completed hearings on the second project, a $135 million proposal to build a new 345,000 volt transmission line between Norwalk, Connecticut and Bethel, Connecticut. A decision is expected in April 2003. The current cost estimate is based on building the entire transmission line aboveground. Alternative proposals have been made to build all or part of the line underground, which likely would result in significantly higher construction costs. CL&P hopes to have the new transmission line operational by the summer of 2005. At December 31, 2002, CL&P has capitalized approximately $8.8 million related to this project.

By mid-2003, CL&P expects to apply to the CSC for approval of a third project, the installation of another 345,000 volt transmission line between Norwalk, Connecticut and Middletown, Connecticut. Estimated construction costs of this overhead line are approximately $500 million. CL&P will jointly construct this project with United Illuminating with CL&P owning 80 percent or approximately $400 million of the project. At December 31, 2002, CL&P has capitalized approximately $2.4 million related to this project.

Construction of these three projects would significantly enhance CL&P's ability to provide reliable electric service to the rapidly growing energy market in southwestern Connecticut. Despite the need for such facilities, significant opposition has been raised. As a result, management cannot be certain as to the expected in-service dates or the ultimate cost of these projects. Should the plans proceed, applicable law provides that CL&P will be able to recover its operating cost and carrying costs through federally approved transmission tariffs.

Yankee Gas has also proposed expansion of its gas distribution system in Connecticut. Yankee Gas' capital expenditures totaled $70.8 million in 2002, compared with $47.8 million in 2001 and $21.6 million in 2000. Yankee Gas expects capital expenditures to total $72.9 million in 2003 as it continues to expand its distribution system and expects to begin work on a liquefied natural gas storage facility proposed in Waterbury, Connecticut.

The expectation that PSNH will retain its generation assets, at least through 2004, will result in higher near-term capital expenditures at PSNH. PSNH's capital expenditures, excluding nuclear fuel, totaled $109.8 million in 2002, compared with $92.6 million in 2001 and $69.5 million in 2000. Capital expenditures are expected to total $116.3 million in 2003, as PSNH continues to upgrade and expand its distribution and transmission system and upgrade its generation plants.

On December 5, 2002, PSNH announced an agreement to acquire the franchise and electric system of Connecticut Valley Electric Company, Inc. (CVEC), a subsidiary of Central Vermont Public Service Corporation (CVPS) that serves approximately 10,000 customers in western New Hampshire. Under the agreement, PSNH will pay CVPS approximately $9 million for its assets and an additional $21 million to terminate a wholesale power contract between CVPS and CVEC. Customers of CVEC will become customers of PSNH, whose residential rates are now approximately 20 percent lower than those of CVEC. PSNH will be allowed to recover the $21 million payment with a return consistent with Part 3 stranded cost treatment under the "Agreement to Settle PSNH Restructuring" (Restructuring Settlement). Part 3 stranded costs are nonsecuritized regulatory assets which must be recovered by a recovery end date determined in accordance with the Restructuring Settlement or be written off. The sale agreement is supported by the New Hampshire Governor's Office, New Hampshire Public Utilities Commission (NHPUC) staff, the state Office of Consumer Advocate, the City of Claremont, and New Hampshire Legal Assistance. The FERC and the NHPUC must approve the sale, which is expected to become effective on January 1, 2004.

As a result of a lower projected growth rate and an adequately sized transmission system to meet near term needs, WMECO does not forecast significant changes in its construction program. WMECO's capital expenditures, excluding nuclear fuel, totaled $23.4 million in 2002, compared with $30.9 million in 2001 and $27.3 million in 2000. WMECO's capital expenditures are expected to total $28.1 million in 2003.

Competitive Energy Subsidiaries: Capital expenditures at NU's competitive generation subsidiaries, NGC and HWP, are expected to be modest in 2003, with $12.1 million at NGC and $3.8 million at HWP. In 2002, NGC's and HWP's capital expenditures totaled $16.4 million and $1 million, respectively.

In recent years, NU has considered several additional investments in the competitive energy business. In 2001, NU proposed constructing a completely new direct current cable between Norwalk, Connecticut and Long Island, New York to serve the merchant power market. However, because of growing financial distress in the merchant power industry, NU concluded that such a project was not feasible at the time and withdrew its proposal from the FERC in November 2002. NU also has considered investing in additional peaking or intermediate generation in the New York and the Mid-Atlantic states. However, NU concluded in 2002 that potential returns on such investments were not adequate given the likely purchase prices.

NU continues to examine niche acquisitions in the energy services business. In 2002, NU acquired Woods Electrical and Woods Network for an aggregate adjusted purchase price of $16.3 million. In 2001, NU acquired the E.S. Boulos Company (Boulos), a high-voltage electrical contractor based in Maine, and Niagara Mohawk Energy Marketing, Inc., an energy marketing company based in New York that was subsequently renamed SENY. Both Boulos and SENY were profitable, with Boulos earning $2.7 million and SENY earning $17.2 million for the year ended December 31, 2002. Since acquisition on July 1, 2002, Woods earned $0.1 million.

Regional Transmission Organization

The FERC has required all transmission owning utilities to voluntarily start forming RTOs or to state why this process has not begun.

NU has been discussing with the other transmission owners in New England the potential to form an Independent Transmission Company (ITC). If formed, the ITC would be a for-profit entity and would perform certain transmission functions required by the FERC, including tariff control, system planning and system operations. The remaining functions required by the FERC would be performed by the ISO regarding the energy market and short-term reliability. Together, the ITC, if formed, and ISO would form the FERC-desired RTO.

In January 2002, the New York and New England ISOs announced their intention to form an RTO. On November 22, 2002, the two ISOs withdrew their joint petition to FERC. The New England ISO intends to make an RTO filing with the transmission owners in New England in 2003.

The agreements needed to create the RTO and to define the working relationships among the ISO and the transmission owners should be created in 2003, and will allow the RTO to begin operation shortly thereafter. The agreements are expected to include provisions for the future creation of one or more ITCs within the RTO. The creation of the RTO will require a FERC rate case, and the impact on NU's return on equity as a result of this rate case cannot be estimated at this time. At December 31, 2002, NU capitalized $1.3 million related to RTO formation activities.

Merchant Energy Company Counterparty Exposures

Certain subsidiaries of NU, including CL&P, Yankee Gas, Select Energy, and NGS, have entered into various transactions with subsidiaries of NRG Energy, Inc. (NRG). NRG's credit rating has been downgraded to below investment grade by all three major rating agencies, and NRG is presently in default on debt service payments. Management does not expect that the resolution of the transactions with NRG will have a material adverse effect on NU's consolidated financial condition or results of operations. Additionally, NU does not have a significant level of exposure to other merchant energy companies. For further information regarding these transactions, see NU's 2002 report on Form 10-K, Item 1, "Business."

Restructuring and Rate Matters

Connecticut – CL&P: Since retail competition began in Connecticut in 2000, an extremely small number of customers have opted to choose an alternate supplier. At December 31, 2002, virtually all of CL&P's customers were procuring their electricity through CL&P's standard offer service. In 2003, Select Energy will continue to supply 50 percent of CL&P's standard offer supply service with NRG Power Marketing, Inc. (NRG-PM), a subsidiary of NRG, contracted to supply 45 percent and a subsidiary of Duke Energy, Inc. contracted to supply the remaining 5 percent of service. On November 18, 2001, at NRG-PM's request, CL&P filed an application with the DPUC to raise the standard offer rate from an average of $0.0495 per kilowatt-hour (kWh) to $0.0595 per kWh to help promote competition in advance of the January 1, 2004 termination of the standard offer period and to provide financial relief to standard offer suppliers. In December 2001, the DPUC rejected CL&P's request, but opened two new dockets to examine the absence of effective retail competition in Connecticut and the financial condition of the suppliers. The first docket culminated in a joint study report issued in a DPUC decision on February 15, 2002, which provided the DPUC's and the Office of Consumer Counsel's findings on how to best structure default service and other issues related to electric industry restructuring. In the second docket, the DPUC concluded on June 17, 2002, that it would not commence further proceedings.

On July 18, 2002, CL&P, concerned with NRG-PM's financial viability, filed a new proposal with the DPUC to maintain current total rates, but to shift $0.007 per kWh from being used to recover stranded costs to instead provide additional payments to NRG-PM and Select Energy to ensure electric reliability in southwestern Connecticut. On July 26, 2002, the DPUC denied the proposal.

CL&P continues to evaluate NRG-PM's ability to meet its obligations under the standard offer service contract. If CL&P is required to seek an alternate source of supply, CL&P would pursue recovery of any additional costs associated with obtaining such supply from NRG-PM pursuant to the contract and may be required to seek DPUC approval to flow through any such costs to customers. Management believes that recovery of these costs, should they be incurred, would be permitted under the provisions of Connecticut's electric utility restructuring legislation and with the DPUC's prior decisions. On February 21, 2003, Fitch Ratings lowered its rating outlook on CL&P to negative as a result of its concern over timely recovery of purchased-power costs if NRG-PM were to default on its CL&P standard offer obligations and CL&P needed to acquire replacement supply service at significantly higher prices.

On September 27, 2001, CL&P filed its application with the DPUC for approval of the disposition of the proceeds in the amount of approximately $1.2 billion from the sale of the Millstone units. This application described and requested DPUC approval for CL&P's treatment of its share of the proceeds from the sale. In accordance with Connecticut's electric utility industry restructuring legislation, CL&P was required to utilize any gains from the Millstone sale to offset stranded costs. The DPUC's final decision regarding this application was issued on February 27, 2003, and increased the amount of net proceeds used to reduce stranded costs by $26.9 million. The earnings impact of the final decision will be reflected in 2003 earnings and will result in an increase in first quarter net income of $2.6 million.

On November 1, 2002, CL&P sold its interest in Seabrook to a subsidiary of FPL Group, Inc. (FPL). The gain on the sale was used to reduce stranded costs.

CL&P continues to be subject to the earnings sharing mechanism implemented by the DPUC, under which CL&P's earnings in excess of a 10.3 percent return on equity will be shared equally by shareholders and ratepayers.

CL&P expects to file a distribution rate case with the DPUC in mid-2003 that would be effective January 1, 2004. Also in the second half of 2003, CL&P will need to secure bids for power supply contracts for 2004 to meet the needs of its customers. Management has not yet identified what level of rates it will request in 2004, but believes that several factors could combine to result in a significant increase in supply costs in 2004. The first is the expiration of current standard offer supply contracts. Another factor is the likely impact of LMP in New England with the implementation of SMD. Implementation of such pricing, which occurred on March 1, 2003, will force Connecticut electric customers to bear the significant additional costs of serving southwestern Connecticut with less efficient local generation because of insufficient transmission capacity to bring cheaper energy into the region. CL&P's completed and planned reliability improvements and transmission construction program will also impact the level of rates management will request in 2004.

Connecticut – Yankee Gas: Following rate proceedings that began in 2001, the DPUC ordered a $4 million rate decrease effective April 1, 2002. The decision endorsed Yankee Gas' distribution expansion plan, subject to annual reviews, and approved, with some conditions, its capital investment ratemaking recovery mechanism, the Infrastructure Expansion Rate Mechanism (IERM). The final decision also authorized an 11 percent return on equity for Yankee Gas and a sharing formula between shareholders and ratepayers for earnings above that level from 2002 through 2005.

On October 1, 2002, Yankee Gas filed supplemental testimony and exhibits to its original IERM filing with the DPUC on August 1, 2002. This filing reflected those 2001 through 2003 system expansion projects that Yankee Gas has undertaken or plans to undertake by December 31, 2003, and that meet certain financial criteria outlined by the DPUC. Yankee Gas is currently proposing no IERM charge for 2003 and that any over-collection for 2003 be carried forward to the 2004 IERM period. A final decision from the DPUC regarding this filing is expected in the first quarter of 2003.

A schedule has been set in Yankee Gas' proceeding before the DPUC to obtain rate approval to build a two billion cubic foot liquefied natural gas storage and production facility in Waterbury, Connecticut. The schedule includes hearings in March 2003 with a final decision in the second quarter of 2003. If approved, construction on the facility, which could cost approximately $60 million, could begin in the fourth quarter of 2003.

In December 2002, the DPUC opened a new docket concerning Yankee Gas overearnings. Hearings related to this docket are scheduled to be held in March 2003 with a final decision scheduled for May 2003, and management cannot determine the ultimate impact of this docket.

New Hampshire: In July 2001, the NHPUC opened a docket to review the fuel and purchased-power adjustment clause (FPPAC) costs incurred between August 2, 1999, and April 30, 2001. Under the Restructuring Settlement, FPPAC deferrals are recovered as a Part 3 stranded cost through the stranded cost recovery charge. On December 31, 2002, the NHPUC issued its final order allowing recovery of virtually all such costs.

On June 28, 2002, PSNH made its first stranded cost recovery charge reconciliation filing with the NHPUC for the period May 1, 2001, through December 31, 2001. This filing reconciles stranded cost revenues against actual stranded cost charges with any difference being credited against stranded costs or deferred for future recovery. Included in the stranded cost charges are the generation costs for the filing period. The generation costs included in this filing were subject to a prudence review by the NHPUC. In January 2003, PSNH entered into a settlement agreement with the Office of Consumer Advocate and the staff of the NHPUC that resolved all outstanding issues. In conjunction with the settlement agreement, the NHPUC staff recommended no disallowances resulting from their review of the outages at PSNH's generating plants. A final order approving the settlement agreement was issued by the NHPUC in February 2003. The NHPUC order approved PSNH's reconciliation of stranded costs as outlined within the Settlement Agreement and had no impact on PSNH's earnings.

On September 12, 2002, the NHPUC issued a final decision approving the auction results in the sale of Seabrook to FPL. On November 1, 2002, the sale was consummated. The proceeds received by NAEC, after NAEC repaid its outstanding debt, were refunded to PSNH through the Seabrook Power Contracts. PSNH used the proceeds received from NAEC to recover stranded costs and repay debt with the remaining proceeds to be returned to NU. As a result of the Seabrook sale, PSNH expects its wholesale electric sales to decline significantly in 2003. However, PSNH expects to generate most of the electricity it needs to serve retail customers from its own generating plants or purchased-power obligations and to purchase the remainder in the wholesale market.

On February 1, 2003, in accordance with the Restructuring Settlement, PSNH raised the transition service rate for residential and small commercial customers to $0.0460 per kWh from $0.0440 per kWh. On the same date, PSNH also raised its transition service rate for large commercial and industrial customers to $0.0467 per kWh from $0.0440 per kWh. PSNH expects these rates to be adequate to recover its generation and purchased-power costs, including the recovery of carrying costs on PSNH's generation investment. If recoveries exceed PSNH's costs, those overrecoveries will be credited against PSNH's Part 3 stranded cost balance. If actual costs exceed those recoveries, PSNH will defer those costs for future recovery from customers through its Stranded Cost Recovery Charge.

PSNH's delivery rates are fixed until February 1, 2004. Under the Restructuring Settlement, PSNH must file a rate case by December 31, 2003, for the purpose of commencing a review of PSNH's delivery rates. Also, under New Hampshire electric industry restructuring statutes, PSNH cannot divest its nonnuclear generation assets until at least February 1, 2004. At this time, management does not expect PSNH to propose selling its 1,200 MW of generation assets.

Massachusetts: In December 2001, the DTE approved approximately a 14 percent reduction in WMECO's overall rates for standard offer service, primarily reflecting a reduction in WMECO's standard offer service supply costs in 2002 to approximately $0.048 per kWh from approximately $0.073 per kWh. In December 2002, the DTE approved an overall increase of approximately 1.8 percent in WMECO's non-contract standard offer rates, primarily reflecting slightly increased standard offer and default service costs as well as other inflationary factors. Select Energy won the bid to supply WMECO with standard offer service in 2003 at an average rate of approximately $0.050 per kWh. An unaffiliated company won a bid to serve WMECO with default service for the period of January 1, 2003, through June 30, 2003, at an average price of $0.051 per kWh.

On June 7, 2002, the DTE issued its decision on WMECO's 1998 through 1999 stranded cost reconciliation. The decision included, among other things, a conclusion that investment tax credits associated with generation assets that have been divested should not be returned to ratepayers. As a result, WMECO recognized approximately $13 million in tax credits during the second quarter of 2002.

On March 30, 2001, WMECO filed its second annual stranded cost reconciliation with the DTE for calendar year 2000. On March 29, 2002, WMECO filed its 2001 annual transition cost reconciliation with the DTE. This filing reconciled the recovery of stranded generation costs for calendar year 2001 and includes sales proceeds from WMECO's portion of the Millstone units, the impact of securitization and approximately a $13 million benefit to ratepayers from WMECO's nuclear performance-based ratemaking process.

Subsequently, WMECO and the office of the Massachusetts Attorney General reached a settlement resolving all transition charge issues for the 1998 through 2001 reconciliations. This settlement was filed for DTE review on December 3, 2002 and approved on December 27, 2002. The settlement had a positive impact of $9 million on WMECO 2002 pretax earnings.

For further information regarding commitments and contingencies related to restructuring, see Note 8A, "Commitments and Contingencies – Restructuring and Rate Matters," to the consolidated financial statements.

Nuclear Generation Asset Divestitures

Seabrook: On November 1, 2002, CL&P, NAEC, and certain other joint owners consummated the sale of their ownership interest in Seabrook.

VYNPC: On July 31, 2002, Vermont Yankee Nuclear Power Corporation (VYNPC) consummated the sale of its nuclear generating unit. NU subsidiaries CL&P, PSNH, and WMECO combined own 17 percent of VYNPC.

Millstone: On March 31, 2001, CL&P and WMECO consummated the sale of Millstone 1 and 2 and CL&P, PSNH and WMECO sold their ownership interests in Millstone 3.

Under the terms of these asset divestitures, the purchasers agreed to assume responsibility for decommissioning their respective units. For further information regarding these divestitures and nuclear decommissioning, see Note 7, "Nuclear Generation Asset Divestitures," and Note 8F, "Nuclear Decommissioning and Plant Closure Costs," to the consolidated financial statements. For further information regarding spent nuclear fuel disposal costs, see Note 8C, "Commitments and Contingencies – Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, assumptions and at times difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact the financial condition of NU. The following describes 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 significant control is maintained and all intercompany transactions between these subsidiaries are eliminated as part of the consolidation process. NU has less than 50 percent ownership interests in the Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company, Maine Yankee Atomic Power Company, VYNPC, two companies that transmit electricity imported from the Hydro-Quebec system, NEON, Acumentrics, and R.M. Services, Inc., which are classified as variable interest entities under Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities," and for which NU was not classified as the primary beneficiary. As a result, management does not expect the adoption of Interpretation No. 46 to result in the consolidation of any currently unconsolidated entities or to have any other material impacts on NU's consolidated financial statements.

Revenue Recognition: Regulated utility revenues are based on rates approved by the state regulatory commissions. These regulated rates are applied to customers' accounts based on their use of energy. 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 their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on generation volumes, estimated customer usage by class, line losses, and applicable customer rates.

Competitive energy subsidiary revenues are recognized at different times for the different businesses. 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.

Energy Trading and Derivative Accounting: On October 1, 2002, NU adopted EITF Issue No. 02-3. The consensuses in EITF Issue No. 02-3 require net reporting of trading revenues and expenses, and rescinded EITF Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities," which had allowed contracts to be marked-to-market based on trading intent. On July 1, 2002, NU adopted net reporting of trading revenues and expenses, as then allowed by EITF Issue No. 98-10. The rescission of EITF Issue No. 98-10 by EITF Issue No. 02-3 also required that contracts that are not derivatives as defined under SFAS No. 133 be removed from the consolidated balance sheets as a cumulative effect of accounting change and no longer recorded at fair value. The adoption of EITF Issue No. 02-3 did not have a material impact on NU's consolidated financial statements.

However, in implementing EITF Issue No. 02-3, Select Energy performed a review of all contracts previously recorded under EITF Issue No. 98-10. In connection with management's review of the contracts in the trading portfolio, the significant changes in the energy trading market and the change in the focus of the energy trading business, certain long-term derivative energy contracts that were included in the trading portfolio and valued at $33.9 million at November 30, 2002, were designated as normal purchases and sales. The impact of the normal purchases and sales designation is that the contracts were adjusted to fair value at November 30, 2002 and were not and will not be adjusted subsequently for changes in fair value. The $33.9 million carrying value of these contracts was reclassified from trading derivative assets to other long-term assets and will be amortized on a straight-line basis to fuel, purchased and net interchange power expense over the remaining terms of the contracts, some of which extend to 2011.

Select Energy uses derivative investments in its trading, wholesale, and retail marketing businesses. The application of derivative accounting under SFAS No. 133 is complex and requires management judgment in the following respects: 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 NU's consolidated net income.

During 2002, approximately $7 million of transmission congestion contracts, which were included in Select Energy's marketing portfolio, were determined to be derivatives. These contracts were recorded at fair value using a valuation model and, at the same time, a valuation reserve on these contracts was recorded due to the lack of available market data. Management continues to believe the amount paid for the contracts best represents their market value. If these assumptions regarding the classification of the contracts change or if new accounting guidance is issued, there may be an impact on NU's consolidated financial statements.

Regulatory Accounting and Assets: 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." CL&P's, PSNH's and WMECO's transmission and distribution businesses 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 regulatory assets. Such a write-off could have a material impact on NU's consolidated financial statements.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on NU's consolidated financial statements. Management believes it is probable that NU's regulated utility companies will recover their investments in long-lived assets, including regulatory assets.

Goodwill and Other Intangible Assets: On January 1, 2002, NU adopted SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 142 requires that management determine reporting units that carry goodwill. The determination of reporting units requires judgment based on how the business segments are managed. SFAS No. 142 also requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment upon adoption and at least annually thereafter by applying a fair value-based test. The fair value-based test involves estimating the fair value of the reporting units by using both discounted cash flow methodologies and an analysis of comparable companies or transactions. The discounted cash flow methodologies that are utilized involve critical assumptions and estimates made by management. If these assumptions are changed there could be a significant impact on NU's consolidated financial statements.

Pension and Postretirement Benefit Obligations: NU's subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Plan) covering substantially all regular NU employees and also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees. 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 resultant 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.

Pre-tax periodic pension income for the Plan, excluding settlements, curtailments, and special termination benefits, totaled $73.4 million and $101 million for the years ended December 31, 2002 and 2001, respectively. Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 9.25 percent for 2002 and 9.5 percent for 2001. NU expects to use a long-term rate of return assumption of 8.75 percent for 2003. The pension 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," associated with early termination programs and the sale of the Millstone and Seabrook nuclear units. Net SFAS No. 88 items totaled $22.2 million of income and $2.6 million in expense for the years ended December 31, 2002 and 2001, respectively. Approximately 30 percent of net pension income is capitalized as a reduction to capital additions to utility plant.

In developing the expected long-term rate of return assumption, NU evaluated input from actuaries, consultants and economists as well as long-term inflation assumptions and NU's historical 20-year compounded return of 10.7 percent. NU's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 45 percent in United States equities and 14 percent in non-United States equities, both with an expected long-term rates of return of 9.25 percent, 3 percent in emerging market equities with an expected long-term return of 10.25 percent, 20 percent in fixed income securities with an expected long-term rate of return of 5.5 percent, 5 percent in high yield fixed income securities with expected long-term rates of return of 7.5 percent, 8 percent in private equities with expected long-term rates of return of 14.25 percent, and 5 percent in real estate with expected long-term rates of return of 7.5 percent. The combination of these target allocations and expected returns results in the overall assumed long-term rate of return of 8.75 percent for 2003. The actual asset allocation at December 31, 2002, was close to these target asset allocations, and NU regularly reviews the actual asset allocations and periodically rebalances the investments to the targeted allocation when appropriate. NU reduced the long-term rate of return assumption by 0.5 percent and 0.25 percent, respectively, each of the last two years due to lower rate of return assumptions for most asset classes. NU believes that 8.75 percent is a reasonable long-term rate of return on Plan assets for 2003. 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.

NU bases the actuarial determination of Plan pension income/expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation 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 value of assets 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 Plan assets. At December 31, 2002, the Plan had cumulative unrecognized investment losses of $507.9 million, which will increase pension expense over the next four years by reducing the expected return on Plan assets. At December 31, 2002, the Plan also had cumulative unrecognized actuarial gains of $89 million, which will reduce pension expense over the expected future working lifetime of active Plan participants, or approximately 13 years. The combined total of unrecognized investment losses and actuarial gains at December 31, 2002 is $418.9 million. This amount impacts the actuarially determined prepaid pension amount recorded on the consolidated balance sheet but has no impact on expected Plan funding.

The discount rate that is utilized in determining future pension obligations is based on a basket of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. To compensate for the Plan's longer duration 0.25 percent was added to this rating. The discount rate determined on this basis has decreased from 7.25 percent at December 31, 2001 to 6.75 percent at December 31, 2002.

Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on Plan assets of 8.75 percent, a discount rate of 6.75 percent and various other assumptions, NU estimates that pension income/expense for the Plan will be approximately $31 million in income, approximately $7 million in expense and approximately $39 million in expense in 2003, 2004 and 2005, respectively. Future actual pension income/expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plan.

The effect of lowering the expected long-term rate of return on Plan assets by 0.5 percent would have reduced pension income for 2002 by approximately $11 million. The effect of lowering the discount rate by 0.5 percent would have also reduced pension income for 2002 by approximately $11 million.

The compensation increase assumption used for 2002 was based on the expected increase in payroll for personnel covered by the Plan. The effect of lowering the compensation increase assumption by 0.5 percent would have increased pension income for 2002 by approximately $5 million.

The value of the Plan assets has decreased from $2 billion at December 31, 2001 to $1.6 billion at December 31, 2002. The investment performance returns and declining discount rates have reduced the funded status of the Plan on a projected benefit obligation (PBO) basis from an overfunded position of $302.8 million at December 31, 2001 to an underfunded position of $157.5 million at December 31, 2002. The PBO includes expectations of future employee service and compensation increases. The significant deterioration in the funded position of the Plan will likely result in Plan contributions sooner than previously expected. NU has not made contributions since 1991. This deterioration could also lead to the requirement under defined benefit plan accounting to record an additional minimum liability. The accumulated benefit obligation (ABO) of the Plan was $78 million less than Plan assets at December 31, 2002. The ABO is the obligation for employee service provided through December 31, 2002. If the ABO exceeds Plan assets, NU will record an additional minimum liability in 2003.

Income Taxes: Income tax expense is calculated in each of the jurisdictions in which NU operates for each period for which a statement of income is presented. 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 of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. NU must also assess the likelihood that the 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. This asset amounted to $331.9 million and $301.3 million at December 31, 2002 and 2001, respectively.

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.

Environmental Matters: At December 31, 2002, NU has recorded a reserve for various environmental liabilities. NU's environmental liabilities are based on the best estimate of the amounts to be incurred for the investigation, remediation and monitoring of the remediation sites. It is possible that future cost estimates will either increase or decrease as additional information becomes known. Changes in future cost estimates will have a smaller impact on NU's subsidiaries that have regulatory mechanisms to recover environmental remediation costs. These subsidiaries include PSNH and Yankee Gas. Yankee Gas recorded an environmental liability for former manufactured gas plant sites of $19.4 million and $22.9 million at December 31, 2002 and 2001, respectively.

Special Purpose Entities and Off-Balance Sheet Financing: NU has a total of seven special purpose entities (SPE), all of which are currently consolidated in the financial statements. 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 such bankruptcy proceedings.

The CL&P Receivables Corporation (CRC) is an SPE that was incorporated on September 5, 1997, and is a wholly owned subsidiary of CL&P. The CRC was established for the sole purpose of selling CL&P's accounts receivable and is included in the consolidation of NU's financial statements. On July 10, 2002 the CRC renewed its Receivables Purchase and Sale Agreement with CL&P and a subsidiary of Citigroup, Inc. (Citigroup). The agreement gives the CRC the right to sell and Citigroup the right to purchase up to $100 million in receivables through July 9, 2003. At December 31, 2002 there was $40 million outstanding under this facility. Sales of receivables to Citigroup under this arrangement meet the accounting criteria for derecognition from the consolidated balance sheets. Accordingly, the $40 million outstanding under this facility is not reflected as debt or included in the consolidated financial statements.

During 2001, SESI established an SPE, HEC/CJTS Energy Center LLC (HEC/CJTS), to provide a bankruptcy-remote entity in connection with an energy project constructed for the State of Connecticut (State). This SPE was established for financing purposes with cooperation from the State Treasurer. HEC/CJTS is limited in the transactions it may enter into and may not initiate an event of bankruptcy without a vote of its sole member and all directors, including independent directors. Pursuant to an engineering, procurement, and construction agreement with the State, SESI constructed a power plant to provide energy and heat to the Connecticut Juvenile Training School (Project), in return for the State entering into a 30-year lease. SESI assigned its interest in the lease with the State to HEC/CJTS in exchange for payments totaling $17.7 million.

During 2001, HEC/CJTS transferred its interest in the lease with the State to unaffiliated investors in exchange for the issuance of $19.2 million of Certificates of Participation (Certificates). This transfer was accounted for as a sale at the beginning of the lease term. HEC/CJTS is included in the accompanying consolidated financial statements, however, upon transfer of the interest in the lease, the debt of $19.2 million created upon issuance of the Certificates was derecognized. No gain or loss was recorded. Proceeds from the issuance of the Certificates, net of issuance costs and net construction interest, were transferred to SESI as payment for the Project construction.

During 1999, SESI established another SPE, HEC/Tobyhanna Energy Project, LLC (HEC/Tobyhanna), to provide a bankruptcy-remote entity 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 are limited to those related to the project and HEC/Tobyhanna, including the Certificates, is included in the accompanying consolidated financial statements.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 3, "Derivative Instruments, Market Risk and Risk Management," Note 4, "Employee Benefits," Note 5, "Goodwill and Other Intangible Assets," Note 6, "Sale of Customer Receivables," and Note 8B, "Commitments and Contingencies – Environmental Matters," to the consolidated financial statements.

Other Matters

Other Commitments and Contingencies: For further information regarding other commitments and contingencies, see Note 8, "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, 2002, is summarized through 2007 as follows:

(Millions of Dollars)	*2003*	*2004*	*2005*	*2006*	*2007*
Notes payable to banks	$ 56.0	$ —	$ —	$ —	$ —
Long-term debt	56.9	61.7	88.7	26.6	8.3
Capital leases	3.1	3.0	2.8	2.7	2.6
Operating leases	23.1	20.6	18.4	16.2	9.8
Long-term contractual arrangements	567.8	551.3	533.0	517.1	364.2
Select Energy purchase agreements	3,302.0	612.6	290.1	68.7	69.2
Totals	$4,008.9	$1,249.2	$933.0	$631.3	$454.1

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 not included in this table. 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 10, "Leases," and Note 8E, "Long-Term Contractual Arrangements," to the consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts including, but not limited to, statements regarding future earnings, refinancings, the use of proceeds from restructuring, and the recovery of operating costs. Words such as estimates, expects, anticipates, intends, plans, and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments, volatility in electric and natural gas commodity markets, and other presently unknown or unforeseen factors.

Results of Operations

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

Income Statement Variances	*2002 over/(under) 2001*		*2001 over/(under) 2000*	
(Millions of Dollars)	*Amount*	*Percent*	*Amount*	*Percent*
Operating Revenues	$(752)	(13)%	$ 92	2%
Operating Expenses:				
Fuel, purchased and net interchange power	(610)	(17)	332	10
Other operation	(21)	(3)	(93)	(11)
Maintenance	5	2	3	1
Depreciation	4	2	(39)	(16)
Amortization	(521)	(53)	706	(a)
Taxes other than income taxes	8	4	(19)	(8)
Gain on sale of utility plant	455	71	(642)	(100)
Total operating expenses	(680)	(13)	248	5
Operating Income	(72)	(13)	(156)	(22)
Interest expense, net	(9)	(3)	(19)	(7)
Other income/(loss), net	(144)	(77)	202	(a)
Income before tax expense	(207)	(46)	65	17
Income tax expense	(92)	(53)	12	8
Preferred dividends of subsidiaries	(2)	(23)	(7)	(49)
Income before extraordinary loss and accounting change	(113)	(43)	60	30
Extraordinary loss, net of tax benefit	—	—	234	100
Cumulative effect of accounting change, net of tax benefit	22	100	(22)	(100)
Net income/(loss)	$ (91)	(38)%	$272	(a)

(a) *Percent greater than 100.*

Operating Revenues

Total revenues decreased by $752 million or 13 percent in the year 2002, compared with the year 2001, primarily due to lower competitive energy revenues ($377 million after intercompany eliminations) and lower regulated subsidiaries revenues due to lower wholesale and transmission revenues ($240 million after intercompany eliminations), and lower regulated retail revenues ($135 million).

The competitive energy companies' revenue decrease in 2002 is primarily due to lower wholesale marketing revenues from Select Energy full requirements contracts, primarily due to lower energy prices. The decrease in regulated wholesale revenues is primarily due to lower sales associated with purchased-power contracts ($91 million), lower PSNH wholesale sales ($94 million), primarily due to a reduction in prices and a lower volume of bilateral transactions and sales of excess capacity and energy, and the 2001 revenue associated with the sale of Millstone output ($42 million). The regulated retail revenue decrease is primarily due to the May 2001 rate decrease for PSNH ($22 million), and the 2002 decrease in the WMECO standard offer energy rate ($77 million), lower Yankee revenue due to lower purchased gas adjustment clause revenue ($59 million) and a combination of the April 2002 rate decrease and lower gas sales ($27 million), partially offset by an increase resulting from the collection of CL&P deferred fuel costs ($25 million) and higher retail electric sales ($25 million). Regulated retail electric kWh sales increased by 1.3 percent, and firm natural gas volume sales decreased by 4.3 percent in 2002.

Total revenues increased by $92 million or 2 percent in the year 2001, compared with the year 2000, primarily due to higher revenues from the competitive energy subsidiaries ($164 million after intercompany eliminations), higher revenues from Yankee Gas ($127 million) and higher regulated retail electric revenues ($33 million), partially offset by lower wholesale regulated revenues ($190 million) and lower transmission revenues ($26 million). The competitive energy subsidiaries' increase is primarily due to higher revenues from Select Energy as a result of new wholesale energy contracts. The Yankee Gas increase was primarily due to a full year of revenue in 2001 versus ten months post merger in 2000. The regulated retail increase is primarily due to a 1.7 percent increase in sales ($41 million), the increase in WMECO's standard offer service rate ($59 million) and the recovery of previously deferred fuel costs for CL&P ($19 million), partially offset by the 5 and 11 percent rate decreases for PSNH that were effective October 1, 2000 and May 1, 2001, respectively ($89 million). Wholesale revenues were lower primarily due to the sale of Millstone at the end of the first quarter of 2001.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expense decreased by $610 million or 17 percent in the year 2002, primarily due to lower wholesale sales from the competitive businesses ($301 million after intercompany eliminations), lower Yankee expense primarily due to lower gas prices ($69 million), and lower purchased-power costs for the regulated subsidiaries ($240 million net of eliminations).

Fuel, purchased and net interchange power expense increased in 2001, primarily due to higher purchased energy and capacity costs as a result of higher sales for Select Energy ($347 million, which reflects eliminations of purchases from other NU subsidiaries), higher expense for Yankee primarily due to a full year in 2001 and higher gas prices ($83 million), and higher expense for WMECO primarily due to the increased cost of the standard offer supply ($70 million), partially offset by lower wholesale cost for CL&P and PSNH ($173 million, net of eliminations).

Other Operation and Maintenance

Other operation and maintenance expenses (O&M) decreased $16 million in 2002, primarily due to lower expenses associated with the regulated businesses ($56 million), partially offset by higher competitive companies' expenses associated with Select Energy's costs of goods sold and the expansion of new businesses ($42 million). The regulated O&M decrease is primarily due to lower nuclear expenses as a result of the sale of the Millstone units at the end of the first quarter in 2001 ($55 million).

Other O&M expenses decreased $90 million in 2001, primarily due to lower nuclear expenses ($133 million) as a result of the sale of the Millstone units at the end of the first quarter of 2001, partially offset by higher O&M expenses for the competitive energy subsidiaries, primarily due to an acquisition made by NGS ($49 million).

Depreciation

Depreciation increased $4 million in 2002, primarily due to higher expense resulting from higher regulated plant balances ($11 million), partially offset by the Millstone unit decommissioning expenses recorded in 2001 ($8 million).

Depreciation expense decreased $39 million in 2001, primarily due to the elimination of decommissioning expenses as a result of the sale of the Millstone units at the end of the first quarter of 2001 ($25 million) and the buydown of the Seabrook Power Contracts ($14 million).

Amortization

Amortization decreased $521 million in 2002, primarily due to the amortization in 2001 related to the gain on sale of the Millstone units ($642 million) and lower amortization related to recovery of the Millstone investment ($45 million), partially offset by the higher PSNH amortization in 2002 primarily related to the gain on the sale of Seabrook ($155 million) and higher amortization related to the regulated companies recovery of stranded costs ($23 million).

Amortization of regulatory assets, net increased in 2001, primarily due to the amortization in 2001 related to the gain on sale of the Millstone units by CL&P and WMECO ($642 million) and higher amortization related to restructuring.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $8 million in 2002, primarily due to CL&P's payments to the Town of Waterford for its loss of property tax revenue resulting from electric utility restructuring ($15 million) and the favorable 2001 property tax settlement with the City of Meriden for CL&P and Yankee, which decreased 2001 taxes ($15 million). These increases were partially offset by the 2002 recognition of a Connecticut sales and use tax audit settlement for the years 1993 through 2001 ($8 million), lower gross earnings taxes ($6 million), lower New Hampshire franchise taxes ($3 million) and lower property taxes ($4 million).

Taxes other than income taxes decreased by $19 million in 2001, primarily due to the reduction in property tax for CL&P and WMECO due to the sale of the Millstone units ($16 million), the property tax settlement with the City of Meriden for CL&P and Yankee in 2001 ($15 million), and lower New Hampshire franchise tax ($5 million), partially offset by higher Connecticut gross earnings taxes ($14 million) on higher CL&P revenues.

Gain on Sale of Utility Plant

Gain on the sale of utility plant decreased $455 million in 2002 primarily due to the gain recognized in the 2001 sale of CL&P's and WMECO's ownership interests in the Millstone units ($642 million), partially offset by CL&P's and NAEC's 2002 sale of Seabrook ($187 million).

Interest Expense, Net

Interest expense, net decreased $9 million in 2002, primarily due to NAEC's reduction of debt.

Interest charges, net decreased in 2001, primarily due to reacquisitions and retirements of long-term debt ($54 million) and higher short-term borrowings in 2000 associated with asset transfers and the Yankee merger ($54 million), partially offset by the interest expense associated with the issuance of rate reduction bonds in 2001 ($88 million).

Other Income/(Loss), Net

Other income/(loss), net decreased $144 million in 2002 primarily due to the 2001 gain related to the Millstone sale ($202 million) and the 2002 investment write-downs ($18 million), partially offset by the 2002 Seabrook related gains ($39 million) and the 2001 loss on share repurchase contracts ($35 million).

Other income/(loss), net increased primarily due to NU's recognition in 2001 of a gain in connection with the sale of the Millstone nuclear units to a subsidiary of Dominion Resources, Inc. (the pre-tax amount of $189 million is included in other income with an offsetting income tax expense impact of $73 million), higher interest and dividend income ($20 million), lower nuclear related costs in 2001 ($18 million), and lower environmental reserve expense in 2001 ($10 million), partially offset by the charge related to the forward purchase of 10.1 million NU common shares ($35 million).

Income Taxes

The consolidated statement of income taxes provides 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 decreased by $92 million in 2002, primarily due to the recognition of WMECO investment tax credits in the second quarter of 2002 and the tax impacts of the Millstone sale in 2001, partially offset by tax impacts of the sale of Seabrook in 2002.

Federal and state income taxes combined increased in 2001, primarily due to higher taxable income. The increase in income taxes as a result of higher taxable income was partially offset by a reduction in income taxes as a result of the favorable resolution of open tax years. For further information regarding income taxes, see the Consolidated Statements of Income Taxes.

Preferred Dividends of Subsidiaries

Preferred dividends decreased in 2001 and 2002 primarily due to lower preferred stock outstanding.

Extraordinary Loss, Net of Tax Benefit

The extraordinary loss in 2000 is primarily due to an after-tax write-off by PSNH of approximately $225 million of stranded costs under the Restructuring Settlement with the state of New Hampshire, combined with other positive effects on PSNH from the discontinuance of SFAS No. 71 ($11 million) and a loss associated with the then pending discontinuance of SFAS No. 71 at HWP and the sale of its assets ($20 million).

Cumulative Effect of Accounting Change, Net of Tax Benefit

The cumulative effect of accounting change, net of tax benefit, recorded in 2001, represents the effect of the adoption of SFAS No. 133, as amended ($22 million).

Company Report

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of Northeast Utilities and subsidiaries and other sections of this annual report. These financial statements, which were audited by Deloitte & Touche LLP in 2002 and 2001, and Arthur Andersen LLP in 2000, 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.

The company has endeavored to establish a control environment that encourages the maintenance of high standards of conduct in all of its business activities. Management is responsible for maintaining a system of internal control over financial reporting, which is designed to provide reasonable assurance, at an appropriate cost-benefit relationship, to the company's management and Board of Trustees regarding the preparation of reliable, published financial statements. The system is supported by an organization of trained management personnel, policies and procedures, and a comprehensive program of internal audits. Through established programs, the company regularly communicates to its management employees their internal control responsibilities and policies prohibiting conflicts of interest.

The Audit Committee of the Board of Trustees is composed entirely of independent trustees. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to review the activities of each and to discuss audit matters, financial reporting matters, and the system of internal control. The Audit Committee also meets periodically with the internal auditors and the independent auditors without management present.

Because of inherent limitations in any system of internal controls, errors or irregularities may occur and not be detected. The company believes, however, that its system of internal accounting control and control environment provide reasonable assurance that its assets are safeguarded from loss or unauthorized use and that its financial records, which are the basis for the preparation of all financial statements, are reliable. Additionally, management believes that its disclosure controls and procedures are in place and operating effectively. Disclosure controls and procedures are designed to ensure that information included in reports such as this annual report is recorded, processed, summarized, and reported within the time periods required and that information disclosed is accumulated and reviewed by management for discussion and approval.

Independent Auditors' Report

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, 2002 and 2001, and the related consolidated statements of income, comprehensive income, shareholders' equity, cash flows and income taxes for the years then ended. The consolidated financial statements of the Company as of December 31, 2000, and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated January 22, 2002. 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 auditing standards generally accepted in the United States of America. 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, the 2002 and 2001 consolidated financial statements present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries (a Massachusetts trust) as of December 31, 2002 and 2001, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1C to the consolidated financial statements, effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. In 2002, the Company adopted Emerging Issues Task Force Issue 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and, retroactively, restated the 2001 consolidated financial statements. Also, as discussed in Note 5, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets," as of January 1, 2002.

As discussed above, the consolidated financial statements of the Company as of December 31, 2000 and for the year then ended were audited by other auditors who have ceased operations. As described in Note 5, the 2001 and 2000 consolidated financial statements have been revised to include the transitional disclosures required by SFAS No. 142, which was adopted by the Company as of January 1, 2002. Our audit-procedures with respect to the disclosures in Note 5 with respect to 2000 included i) agreeing the previously reported net income to the previously issued consolidated financial statements and the adjustments to reported net income representing amortization expense (including any related tax effects) recognized in that period related to goodwill and intangible assets that are no longer being amortized as a result of initially applying SFAS No. 142 (including any related tax effects) to the

Company's underlying records obtained from management, and ii) testing the mathematical accuracy of the reconciliation of adjusted net income to reported net income, and the related earnings-per-share amounts. In our opinion, the disclosures in Note 5 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2000 consolidated financial statements of the Company other than with respect to such disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2000 consolidated financial statements taken as a whole.

DELOITTE & TOUCHE LLP

Hartford, Connecticut
January 28, 2003
(February 27, 2003 as to Note 8A)

Report of Independent Public Accountants

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 (a Massachusetts trust) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, comprehensive income, shareholders' equity, cash flows, and income taxes for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the 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, the financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1C to the consolidated financial statements, effective January 1, 2001, the company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

ARTHUR ANDERSEN LLP

Hartford, Connecticut
January 22, 2002

Readers of these consolidated financial statements should be aware that this report is a copy of a previously issued Arthur Andersen LLP report and that this report has not been reissued by Arthur Andersen LLP. Furthermore, this report has not been updated since January 22, 2002, and Arthur Andersen LLP completed its last post-audit review of December 31, 2001, consolidated financial information on May 13, 2002.

Readers should also be aware that amounts previously reported have been reclassified with the adoption of net reporting, which is discussed in Note 1C to the consolidated financial statements. The 2001 consolidated financial statements have been reaudited by Deloitte & Touche LLP.

Consolidated Balance Sheets

(Thousands of Dollars)	At December 31, 2002	2001
Assets		
Current Assets:		
Cash and cash equivalents	$ 85,393	$ 96,658
Investments in securitizable assets	178,908	206,367
Receivables, less provision for uncollectible accounts of $15,425 in 2002 and $16,353 in 2001	767,089	659,759
Unbilled revenues	126,236	126,398
Fuel, materials and supplies, at average cost	119,853	108,516
Special deposits	2,455	60,261
Derivative assets	130,929	150,299
Prepayments and other	110,261	67,910
	1,521,124	1,476,168
Property, Plant and Equipment:		
Electric utility	5,141,887	5,743,575
Gas utility	679,055	634,884
Competitive energy	866,294	850,061
Other	205,115	195,741
	6,892,351	7,424,261
Less: Accumulated depreciation	2,484,549	3,273,737
	4,407,802	4,150,524
Construction work in progress	320,567	289,889
Nuclear fuel, net	—	32,564
	4,728,369	4,472,977
Deferred Debits and Other Assets:		
Regulatory assets	2,910,029	3,287,537
Goodwill and other purchased intangible assets, net	345,867	333,123
Prepaid pension	328,890	232,398
Nuclear decommissioning trusts, at market	—	61,713
Other	433,338	468,007
	4,018,124	4,382,778
Total Assets	$10,267,617	$10,331,923

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

Consolidated Balance Sheets

(Thousands of Dollars)	At December 31, 2002	2001
Liabilities and Capitalization		
Current Liabilities:		
Notes payable to banks	$ 56,000	$ 290,500
Long-term debt – current portion	56,906	50,462
Accounts payable	766,128	608,705
Accrued taxes	141,667	27,371
Accrued interest	40,597	35,659
Derivative liabilities	63,900	151,648
Other	179,154	161,277
	1,304,352	1,325,622
Rate Reduction Bonds	1,899,312	2,018,351
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,436,507	1,491,394
Accumulated deferred investment tax credits	106,471	120,071
Deferred contractual obligations	354,469	216,566
Other	552,641	633,523
	2,450,088	2,461,554
Capitalization:		
Long-Term Debt	2,287,144	2,292,556
Preferred Stock – Nonredeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value – authorized 225,000,000 shares; 149,375,847 shares issued and 127,562,031 shares outstanding in 2002 and 148,890,640 shares issued and 130,132,136 shares outstanding in 2001	746,879	744,453
Capital surplus, paid in	1,108,338	1,107,609
Deferred contribution plan – employee stock ownership plan	(87,746)	(101,809)
Retained earnings	765,611	678,460
Accumulated other comprehensive income/(loss)	14,927	(32,470)
Treasury stock, 18,022,415 shares in 2002 and 14,359,628 in 2001	(337,488)	(278,603)
Common Shareholders' Equity	2,210,521	2,117,640
Total Capitalization	4,613,865	4,526,396
Commitments and Contingencies (Note 8)		
Total Liabilities and Capitalization	$10,267,617	$10,331,923

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, 2002	2001	2000
Operating Revenues	$5,216,321	$5,968,220	$5,876,620
Operating Expenses:			
Operation –			
Fuel, purchased and net interchange power	3,026,102	3,635,736	3,303,995
Other	752,482	773,058	866,742
Maintenance	263,487	258,961	255,884
Depreciation	205,646	201,013	239,798
Amortization	461,544	983,037	276,821
Taxes other than income taxes	227,518	219,197	238,587
Gain on sale of utility plant	(187,113)	(641,956)	—
Total operating expenses	4,749,666	5,429,046	5,181,827
Operating Income	466,655	539,174	694,793
Interest Expense:			
Interest on long-term debt	134,471	140,497	194,406
Interest on rate reduction bonds	115,791	87,616	—
Other interest	20,249	51,545	104,896
Interest expense, net	270,511	279,658	299,302
Other Income/(Loss), Net	43,828	187,627	(14,309)
Income Before Income Tax Expense	239,972	447,143	381,182
Income Tax Expense	82,304	173,952	161,725
Income Before Preferred Dividends of Subsidiaries	157,668	273,191	219,457
Preferred Dividends of Subsidiaries	5,559	7,249	14,162
Income Before Cumulative Effect of Accounting Change and Extraordinary Loss, Net of Tax Benefits	152,109	265,942	205,295
Cumulative effect of accounting change, net of tax benefit of $14,908	—	(22,432)	—
Extraordinary loss, net of tax benefit of $169,562	—	—	(233,881)
Net Income/(Loss)	$ 152,109	$ 243,510	$ (28,586)
Basic Earnings/(Loss) Per Common Share:			
Income before cumulative effect of accounting change and extraordinary loss, net of tax benefits	$ 1.18	$ 1.97	$ 1.45
Cumulative effect of accounting change, net of tax benefit	—	(0.17)	—
Extraordinary loss, net of tax benefit	—	—	(1.65)
Basic Earnings/(Loss) Per Common Share	$ 1.18	$ 1.80	$ (0.20)
Fully Diluted Earnings/(Loss) Per Common Share:			
Income before cumulative effect of accounting change and extraordinary loss, net of tax benefits	$ 1.18	$ 1.96	$ 1.45
Cumulative effect of accounting change, net of tax benefit	—	(0.17)	—
Extraordinary loss, net of tax benefit	—	—	(1.65)
Fully Diluted Earnings/(Loss) Per Common Share	$ 1.18	$ 1.79	$ (0.20)
Basic Common Shares Outstanding (average)	129,150,549	135,632,126	141,549,860
Fully Diluted Common Shares Outstanding (average)	129,341,360	135,917,423	141,967,216

Consolidated Statements of Comprehensive Income

(Thousands of Dollars)	For the Years Ended December 31, 2002	2001	2000
Net Income/(Loss)	$152,109	$243,510	$(28,586)
Other Comprehensive Income/(Loss), Net of Tax:			
Qualified cash flow hedging instruments	52,360	(36,859)	—
Unrealized (losses)/gains on securities	(5,121)	2,620	245
Minimum pension liability adjustments	158	—	—
Other comprehensive income/(loss), net of tax	47,397	(34,239)	245
Comprehensive Income/(Loss)	$199,506	$209,271	$(28,341)

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

Consolidated Statements of Shareholders' Equity

(Thousands of Dollars)	*Common Shares*	*Capital Surplus, Paid In*	*Deferred Contribution Plan – ESOP*	*Retained Earnings (a)*	*Accumulated Other Comprehensive Income/(Loss)*	*Treasury Stock*	*Total*
Balance as of January 1, 2000	$ 686,969	$ 942,025	$ (127,725)	$ 581,817	$ 1,524	$ (1,299)	$ 2,083,311
Net loss for 2000				(28,586)			(28,586)
Cash dividends on common shares – $0.40 per share				(57,358)			(57,358)
Issuance of 11,388,032 common shares, $5 par value	56,940	164,443					221,383
Transaction fee on forward share purchase arrangement						(13,786)	(13,786)
Allocation of benefits – ESOP		(1,617)	13,262				11,645
Redemption of preferred stock		(749)					(749)
Capital stock expenses, net		2,478					2,478
Other comprehensive income					245		245
Balance as of December 31, 2000	743,909	1,106,580	(114,463)	495,873	1,769	(15,085)	2,218,583
Net income for 2001				243,510			243,510
Cash dividends on common shares – $0.45 per share				(60,923)			(60,923)
Issuance of 108,779 common shares, $5 par value	544	1,207					1,751
Allocation of benefits – ESOP		(2,296)	12,654				10,358
Repurchase of common shares						(293,452)	(293,452)
Mark-to-market on forward share purchase arrangement						29,934	29,934
Capital stock expenses, net		2,118					2,118
Other comprehensive loss					(34,239)		(34,239)
Balance as of December 31, 2001	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 485,207 common shares, $5 par value	2,426	5,032					7,458
Allocation of benefits – ESOP and restricted stock		(4,679)	14,063	2,835			12,219
Repurchase of common shares						(58,885)	(58,885)
Capital stock expenses, net		376					376
Other comprehensive income					47,397		47,397
Balance as of December 31, 2002	$746,879	$1,108,338	$ (87,746)	$765,611	$14,927	$(337,488)	$2,210,521

(a) 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, 2002, retained earnings available for payment of dividends totaled $318.3 million.

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,* *2002*	*2001*	*2000*
Operating Activities:			
Income before preferred dividends of subsidiaries	$157,668	$ 273,191	$219,457
Adjustments to reconcile to net cash flows provided by operating activities:			
Depreciation	205,646	201,013	239,798
Deferred income taxes and investment tax credits, net	(149,325)	(116,704)	(16,117)
Amortization	461,544	983,037	276,821
Net amortization/(deferral) of recoverable energy costs	27,623	(2,005)	(30,603)
Gain on sale of utility plant	(187,113)	(641,956)	—
Cumulative effect of accounting change, net of tax	—	(22,432)	—
Prepaid pension	(96,492)	(92,852)	(138,877)
Net other sources/(uses) of cash	10,707	(65,064)	88,967
Changes in working capital:			
Receivables and unbilled revenues, net	(102,181)	(301,068)	(104,868)
Fuel, materials and supplies	(27,590)	55,195	12,450
Accounts payable	153,450	100,277	171,148
Accrued taxes	114,296	(27,439)	(128,107)
Investments in securitizable assets	27,459	61,779	9,474
Other working capital (excludes cash)	16,953	(76,366)	254
Net cash flows provided by operating activities	612,645	328,606	599,797
Investing Activities:			
Investments in plant:			
Electric, gas and other utility plant	(468,842)	(428,312)	(345,596)
Competitive energy assets	(23,150)	(15,368)	(7,140)
Nuclear fuel	(465)	(14,275)	(61,286)
Cash flows used for investments in plant	(492,457)	(457,955)	(414,022)
Investments in nuclear decommissioning trusts	(9,876)	(105,076)	(39,550)
Net proceeds from the sale of utility plant	366,786	1,045,284	—
Buyout/buydown of IPP contracts	(5,152)	(1,157,172)	—
Payment for acquisitions, net of cash acquired	(16,351)	(31,699)	(260,347)
Other investment activities, net	15,234	(51,677)	(28,478)
Net cash flows used in investing activities	(141,816)	(758,295)	(742,397)
Financing Activities:			
Issuance of common shares	7,458	1,751	4,269
Repurchase of common shares	(57,800)	(291,789)	—
Issuance of long-term debt	310,648	703,000	26,477
Issuance of rate reduction bonds	50,000	2,118,400	—
Retirement of rate reduction bonds	(169,039)	(100,049)	—
Net (decrease)/increase in short-term debt	(234,500)	(1,019,477)	961,977
Reacquisitions and retirements of long-term debt	(314,773)	(714,226)	(685,555)
Reacquisitions and retirements of preferred stock	—	(60,768)	(126,771)
Retirement of monthly income preferred securities	—	(100,000)	—
Retirement of capital lease obligation	—	(180,000)	—
Cash dividends on preferred stock	(5,559)	(7,249)	(14,162)
Cash dividends on common shares	(67,793)	(60,923)	(57,358)
Other financing activities, net	(736)	37,660	(21,414)
Net cash flows (used in)/provided by financing activities	(482,094)	326,330	87,463
Net decrease in cash and cash equivalents	(11,265)	(103,359)	(55,137)
Cash and cash equivalents – beginning of year	96,658	200,017	255,154
Cash and cash equivalents – end of year	$ 85,393	$ 96,658	$200,017

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

Consolidated Statements of Capitalization

(Thousands of Dollars)		At December 31, 2002	2001
Common Shareholders' Equity		$2,210,521	$2,117,640
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption – $50 par value – authorized 9,000,000 shares in 2002 and 2001; 2,324,000 shares outstanding in 2002 and 2001; Dividend rates of $1.90 to $3.28; Current redemption prices of $50.50 to $54.00		116,200	116,200
Long-Term Debt: (a)			
First Mortgage Bonds –			
Final Maturity	Interest Rates		
2005	5.00% to 6.75%	116,000	140,000
2009-2012	6.20% to 7.19%	80,000	80,000
2019-2024	7.88% to 10.07%	254,995	255,945
2026	8.81%	320,000	320,000
Total First Mortgage Bonds		770,995	795,945
Other Long-Term Debt – Pollution Control Notes and Other Notes – (b)			
2003-2012	6.24% to 8.58% and Adjustable Rate	358,400	381,500
2016-2018	5.90%	25,400	25,400
2021-2022	Adjustable Rate and 1.55% to 6.00%	428,285	428,285
2028	5.85% to 5.95%	369,300	369,300
2031	Adjustable Rate	62,000	62,000
Total Pollution Control Notes and Other Notes		1,243,385	1,266,485
Fees and interest due for spent nuclear fuel disposal costs (c)		253,638	249,314
Other		80,181	36,257
Total Other Long-Term Debt		1,577,204	1,552,056
Unamortized premium and discount, net		(4,149)	(4,983)
Total Long-Term Debt		2,344,050	2,343,018
Less: Amounts due within one year		56,906	50,462
Long-Term Debt, Net		2,287,144	2,292,556
Total Capitalization		$4,613,865	$4,526,396

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

Notes to Consolidated Statements of Capitalization

(a) Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2002, for the years 2003 through 2007 and thereafter, excluding fees and interest due for spent nuclear fuel disposal costs of $253.6 million and unamortized premiums and discounts of $4.1 million are $56.9 million, $61.7 million, $88.7 million, $26.6 million, $8.3 million, and $1,852.4 million, respectively.

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

CL&P has $315.5 million of pollution control notes secured by second mortgage liens on transmission assets, junior to the liens of their first mortgage bond indentures.

CL&P has $62 million of tax-exempt Pollution Control Revenue Bonds (PCRBs) with bond insurance secured by the first mortgage bonds and a liquidity facility. For financial reporting purposes, these first mortgage bonds would not be considered outstanding 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, 2002 and 2001, $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.

(b) The average effective interest rate on the variable-rate pollution control notes ranged from 1.2 percent to 1.7 percent for 2002 and 1.2 percent to 3.8 percent for 2001. NU's variable rate long-term debt maturities and cash sinking fund requirements are $178.5 million in 2021 and $62 million in 2031.

(c) For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 8C, "Commitments and Contingencies – Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

Consolidated Statements of Income Taxes

(Thousands of Dollars)	*For the Years Ended December 31,* 2002	2001	2000
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 197,426	$244,501	$154,790
State	34,204	46,155	23,052
Total current	231,630	290,656	177,842
Deferred income taxes, net:			
Federal	(108,524)	(80,968)	7,297
State	(14,210)	(15,644)	(5,529)
Total deferred	(122,734)	(96,612)	1,768
Investment tax credits, net	(26,592)	(20,092)	(17,885)
Total income tax expense	$ 82,304	$173,952	$161,725
Deferred income taxes are comprised of the tax effects of temporary differences as follows:			
Deferred tax asset associated with net operating losses	$ —	$ 2,206	$ 1,563
Depreciation, leased nuclear fuel, settlement credits and disposal costs	89,621	(185,850)	9,514
Regulatory deferral	(141,592)	(33,187)	(34,486)
Regulatory disallowance	345	2,323	—
Sale of generation assets	(20,500)	(225,019)	—
Pension	(1,720)	24,183	25,751
Loss on bond redemptions	(1,084)	12,396	655
Securitized contract termination costs and other	(23,044)	279,673	—
Contract settlements	(14,991)	16,640	(4,442)
Other	(9,769)	10,023	3,213
Deferred income taxes, net	$(122,734)	$ (96,612)	$ 1,768
A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:			
Expected federal income tax	$ 81,400	$156,500	$133,413
Tax effect of differences:			
Depreciation	10,404	5,313	2,882
Amortization of regulatory assets	13,540	5,748	16,835
Investment tax credit amortization	(26,592)	(20,092)	(17,885)
State income taxes, net of federal benefit	12,996	19,832	11,390
Dividends received deduction	(3,237)	(3,382)	(8,618)
Tax asset valuation allowance/reserve adjustments	(1,310)	(7,000)	(2,136)
Merger-related expenditures	—	(4,589)	5,829
Amortization of PSNH acquisition costs	1,426	4,512	9,946
Nondeductible stock expenses	—	12,388	—
Other, net	(6,323)	4,722	10,069
Total income tax expense	$ 82,304	$173,952	$161,725

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

Notes To Consolidated Financial Statements

1. Summary of Significant Accounting Policies

A. About Northeast Utilities

Northeast Utilities (NU or the company) is the parent company of the Northeast Utilities system. NU's regulated utilities furnish franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through three wholly owned subsidiaries: The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH) and Western Massachusetts Electric Company (WMECO). Another wholly owned subsidiary, North Atlantic Energy Corporation (NAEC), previously sold all of its entitlement to the capacity and output of the Seabrook Station 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. Other subsidiaries include Holyoke Water Power Company (HWP), a company engaged in the production of electric power, and Yankee Energy System, Inc. (Yankee), the parent company of Yankee Gas Services Company (Yankee Gas), Connecticut's largest natural gas distribution system.

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 NU's 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 operating subsidiaries are subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions.

NU Enterprises, Inc. (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 Select Energy, Inc., and subsidiary (Select Energy), a corporation engaged in the trading, marketing, transportation, storage, and sale of energy commodities, at wholesale and retail, in designated geographical areas; Northeast Generation Company (NGC), a corporation that acquires and manages generation facilities; Select Energy Services, Inc. and subsidiaries (SESI), a provider of energy management, demand-side management and related consulting services for commercial, industrial and institutional electric companies and electric utility companies, and; Northeast Generation Services Company and subsidiaries (NGS), a corporation that maintains and services fossil or hydroelectric facilities and provides third-party electrical, mechanical, and engineering contracting services.

In July 2002, the competitive energy subsidiaries acquired certain assets and assumed certain liabilities of Woods Electrical Co. Inc., (Woods Electrical), an electrical services company, and Woods Network Services, Inc. (Woods Network), a network products and services company for an aggregate adjusted purchase price of $16.3 million. Woods Electrical is wholly owned by NGS, and Woods Network is wholly owned by NUEI.

Another subsidiary is Mode 1 Communications, Inc. (Mode 1), an investor in a fiber-optic communications network.

Several wholly owned subsidiaries of NU provide support services for NU's companies and, in some cases, for other New England utilities. Northeast Utilities Service Company provides centralized accounting, administrative, engineering, financial, information resources, legal, operational, planning, purchasing, and other services to NU's companies. Until the sale of Seabrook on November 1, 2002, North Atlantic Energy Service Corporation (NAESCO) had operational responsibility for Seabrook. Three other subsidiaries construct, acquire or lease some of the property and facilities used by NU's companies.

B. Presentation

The consolidated financial statements of NU include the accounts of all 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 contingent liabilities 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.

Certain reclassifications of prior years' data have been made to conform with the current year's presentation.

C. New Accounting Standards

Energy Trading and Risk Management Activities: In June 2002, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) reached a consensus on EITF Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," requiring companies engaged in energy trading activities to classify revenues and expenses associated with energy trading contracts on a net basis in revenues, rather than recording revenues for sales and expenses for purchases. While this consensus was subsequently rescinded by the EITF on October 25, 2002, NU chose to adopt net reporting of energy trading revenues and expenses for contracts that physically settle effective July 1, 2002. Operating revenues and fuel, purchased and net interchange power for the year ended December 31, 2002 reflect net reporting, and the adoption of net reporting was applied retroactively to 2001 operating revenues and fuel, purchased and net interchange power but had no effect on net income.

The impact on previously reported amounts in 2001 is as follows:

(Millions of Dollars)	
Operating Revenues:	
As previously reported	$6,873.8
Impact of reclassification	(905.6)
As currently reported	$5,968.2
Fuel, Purchased and Net Interchange Power:	
As previously reported	$4,541.3
Impact of reclassification	(905.6)
As currently reported	$3,635.7

Operating revenues and fuel, purchased and net interchange power for the year ended December 31, 2000 were not adjusted, as the impact of net reporting was not material to NU's consolidated results of operations in 2000.

On October 25, 2002, the EITF reached additional consensuses in EITF Issue No. 02-3. These consensuses supercede the consensuses the EITF reached in June 2002. The first consensus rescinds EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities for Energy Trading Activities," under which Select Energy previously accounted for energy trading activities. This consensus requires companies engaged in energy trading activities to discontinue fair value accounting effective January 1, 2003, for contracts that do not meet the definition of a derivative in Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, effective January 1, 2003. NU adopted this consensus effective October 1, 2002. Management determined that there were no trading contracts subject to fair value accounting that did not meet the definition of a derivative in SFAS No. 133. Accordingly, there was no cumulative effect of an accounting change.

The second consensus requires that companies engaged in energy trading activities classify revenues and expenses associated with energy trading contracts on a net basis in revenues effective January 1, 2003. NU adopted net reporting effective July 1, 2002, before this consensus was reached by the EITF.

Asset Retirement Obligations: In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." 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 is effective on January 1, 2003, for NU. Management has completed its review process for potential asset retirement obligations (AROs) and has not identified any material AROs which have been incurred. However, management has identified certain removal obligations which arise in the ordinary course of business that either have a low probability of occurring or are not material in nature. 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.

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. At December 31, 2002, NU maintained approximately $321 million in cost of removal regulatory liabilities, which are included in the accumulated provision for depreciation.

Stock-Based Compensation: In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." This statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for a voluntary change to the fair value-based method of accounting for stock-based employee compensation and requires prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for 2002, and NU included the disclosures required by SFAS No. 148 in this annual report. For the required disclosures, see Note 1K, "Summary of Significant Accounting Policies – Stock-Based Compensation" and Note 4D, "Employee Benefits – Stock-Based Compensation" to the consolidated financial statements. At this time, NU has not elected to transition to the fair value-based method of accounting for stock-based employee compensation.

Guarantees: In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Interpretation No. 45 requires that disclosures be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued and clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. Interpretation No. 45 does not apply to certain guarantee contracts, such as residual value guarantees provided by lessees in capital leases, guarantees that are accounted for as derivatives, guarantees that represent contingent consideration in a business combination, guarantees issued between either parents and their subsidiaries or corporations under common control, a parent's guarantee of a subsidiary's debt to a third party, and a subsidiary's guarantee of the debt owed to a third party by either its parent or another subsidiary of that parent. The initial recognition and initial measurement provisions of Interpretation No. 45 are applicable to NU on a prospective basis to guarantees issued or modified after January 1, 2003. Currently, management does not expect the adoption of the initial recognition and initial measurement provisions of Interpretation No. 45 to have a material impact on NU's consolidated financial statements. The disclosure requirements in Interpretation No. 45 are effective for 2002. For further information regarding these disclosures, see Note 2, "Short-Term Debt" to the consolidated financial statements.

Consolidation of Variable Interest Entities: In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities." Interpretation No. 46 addresses the consolidation and disclosure requirements for companies that hold an equity interest in a variable interest entity (VIE), regardless of the date on which the VIE was created. Interpretation No. 46 requires consolidation of a VIE's assets, liabilities and noncontrolling interests at fair value when a company is the primary beneficiary, which is defined as a company that absorbs a majority of the expected losses, risks and revenues from the VIE as a result of holding a contractual or other financial interest in the VIE. Consolidation is not required under Interpretation No. 46 for those companies that hold a significant equity interest in a VIE but are not the primary beneficiary. Interpretation No. 46 is effective for NU beginning in the third quarter of 2003. At December 31, 2002, NU held equity interests in various VIEs, for which NU was not the primary beneficiary, as NU does not absorb a majority of the expected losses, risks and revenues from the VIEs or provide a substantial portion of financial support. As a result, management does not expect the adoption of Interpretation No. 46 to have a material impact on NU's consolidated financial statements. For further information regarding NU's investments in its VIEs, see Note 1D, "Equity Investments and Jointly Owned Electric Utility Plant" to the consolidated financial statements.

Derivative Instruments: Effective January 1, 2001, NU adopted SFAS No. 133, as amended. All derivative instruments have been identified and recorded at fair value effective January 1, 2001. In addition, for those derivative instruments which are hedging an identified risk, NU has designated and documented all hedging relationships. For those contracts that do not meet the hedging requirements, the changes in fair value of those contracts were recognized currently in earnings.

D. Equity Investments and Jointly Owned Electric Utility Plant

Regional Nuclear Generating Companies: CL&P, PSNH and WMECO own common stock in four regional nuclear companies (Yankee Companies). NU's ownership interests in the Yankee Companies at December 31, 2002 and 2001, 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), 20 percent of the Maine Yankee Atomic Power Company (MYAPC), and 17 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC). NU's total equity investment in the Yankee Companies and its exposure to loss as a result of these investments at December 31, 2002 and 2001, is $48.9 million and $52.5 million, respectively. These investments are VIE's under FASB Interpretation No. 46. Excluding VYNPC, which sold its nuclear generating plant, each Yankee Company owns a single decommissioned nuclear generating plant. On July 31, 2002, VYNPC consummated the sale of its nuclear generating plant to a subsidiary of Entergy Corporation for approximately $180 million.

Seabrook: CL&P and NAEC together previously had a 40.04 percent joint ownership interest in Seabrook, a 1,148 megawatt nuclear generating unit. 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). At December 31, 2001, plant-in-service and the accumulated provision for depreciation for NU's share of Seabrook totaled $912.5 million and $840.6 million, respectively.

Hydro-Quebec: NU has a 22.66 percent equity ownership interest and an exposure to loss as a result of this investment totaling $12 million and $13.6 million at December 31, 2002 and 2001, respectively, in two companies that transmit electricity imported from the Hydro-Quebec system in Canada. This investment is a VIE under the FASB Interpretation No. 46.

Other Investments: NU also maintains certain cost method, equity method, and other investments in NEON Communications, Inc. (NEON), a provider of high-bandwidth fiber optic telecommunications services, Acumentrics Corporation (Acumentrics), a privately owned producer of advanced power generation and power protection technologies applicable to homes, telecommunications, commercial businesses, industrial facilities, and the auto industry, R.M. Services, Inc. (RMS), a provider of consumer collection services for companies throughout the United States, and BMC Energy LLC (BMC), an operator of renewable energy projects. These investments have a combined total carrying value of $29.1 million and $54 million at December 31, 2002 and 2001, respectively. During 2002, after-tax impairment write-offs were recorded to reduce the carrying values of NEON, Acumentrics and RMS to their net realizable values. Excluding BMC, these investments are VIEs under FASB Interpretation No. 46, and NU's exposure to loss as a result of these investments totaled $24.4 million and $49.3 million at December 31, 2002 and 2001, respectively. In 2001, based on a reduction in its ownership share in NEON, NU changed from the equity method of accounting to the cost method of accounting for this investment.

E. Depreciation

The provision for depreciation is calculated using the straight-line method based on the estimated remaining useful lives of depreciable utility 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 they are 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. The depreciation rates for the several classes of electric utility plant-in-service are equivalent to a composite rate of 3.2 percent in 2002 and 3.1 percent in 2001 and 2000.

In 2002, the competitive energy subsidiaries 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 remaining years. In addition, the useful lives of certain software was revised and shortened to reflect a remaining life of 1.5 years. As a result of these studies, NU's operating expenses decreased by approximately $5.1 million or $0.04 per share on a fully diluted basis in 2002.

In 2000, HWP discontinued SFAS No. 71, "Accounting for the Effect of Certain Types of Regulation," and recorded a charge to accumulated depreciation for the plant carrying value in excess of fair value for certain hydroelectric generation assets, which was recorded as an extraordinary loss. These assets were sold in the fourth quarter of 2001.

F. Revenues

Regulated utility revenues are based on rates approved by the state regulatory commissions. These regulated rates are applied to customer's accounts based on their use of energy. 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 their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on generation volumes, estimated customer usage by class, line losses, and applicable customer rates.

Competitive energy subsidiary revenues are recognized at different times for the different businesses. 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.

G. Regulatory Accounting and Assets

The accounting policies of NU's regulated utilities 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.

CL&P's, PSNH's and WMECO's transmission and distribution businesses 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 also believes it is probable that NU's operating companies will recover their investments in long-lived assets, including regulatory assets. In addition, all material regulatory assets are earning a return, except for securitized regulatory assets. The components of NU's regulatory assets are as follows:

(Millions of Dollars)	*At December 31, 2002*	*2001*
Recoverable nuclear costs	$ 85.4	$ 243.1
Securitized regulatory assets	1,891.8	2,004.1
Income taxes, net	331.9	301.3
Unrecovered contractual obligations	239.3	78.3
Recoverable energy costs, net	299.6	327.2
Other	62.0	333.5
Totals	$2,910.0	$3,287.5

In March 2000, CL&P and WMECO completed the auction of certain hydroelectric generation assets with a book value of $129 million. NGC was the winning bidder in the auction and paid approximately $865.5 million for these assets. Restructuring legislation in both Connecticut and Massachusetts requires gains from the sale of generation to be used to reduce regulatory assets and other stranded costs. Since the entities to the transaction are all wholly owned by NU, a gain was not recognized. The purchase price of the hydroelectric generation assets is reflected in competitive energy property, plant and equipment, and NGC is depreciating the plant assets over their estimated useful life.

In March 2001, CL&P and WMECO sold their ownership interests in the Millstone units. The gain on these sales in the amount of approximately $521.6 million and $119.8 million, respectively, for CL&P and WMECO were used to offset recoverable nuclear costs, resulting in a total unamortized balance of $13.1 million and $158.1 million at December 31, 2002 and 2001, respectively. Additionally, PSNH recorded a regulatory asset in conjunction with the sale of the Millstone units with an unamortized balance of $36.8 million and $40.5 million at December 31, 2002 and 2001, which is also included in recoverable nuclear costs. Also included in recoverable nuclear costs for 2002 and 2001 are $35.5 million and $44.5 million, respectively, primarily related to Millstone 1 recoverable nuclear costs associated with the recoverable portion of the undepreciated plant and related assets.

In 2000, PSNH discontinued the application of SFAS No. 71 for its generation business and created a regulatory asset for Seabrook over market generation. In April 2001, PSNH issued rate reduction bonds in the amount of $525 million. PSNH used the majority of this amount to buydown its power contracts with NAEC. The Seabrook over market generation was securitized at that time and is reflected in securitized regulatory assets at December 31, 2002 and 2001. On May 22, 2001, the Governor of New Hampshire signed a bill modifying the state's electric utility industry restructuring laws delaying the sale of PSNH's fossil and hydroelectric generation assets until at least February 1, 2004. Since then there has been no regulatory action, and management currently has no plans to divest these generation assets. As the NHPUC has allowed and is expected to continue to allow rate recovery of a return of and on these generation assets, as well as all operating expenses, PSNH again meets the criteria for the application of SFAS No. 71 for the generation portion of its business. Accordingly, costs related to the 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 nonsecuritized regulatory assets which must be recovered by a recovery end date determined in accordance with the Restructuring Settlement or be written off.

In March 2001, CL&P issued $1.4 billion in rate reduction certificates and used $1.1 billion of those proceeds to buyout or buydown certain contracts with independent power producers. In May 2001, WMECO issued $155 million in rate reduction certificates and used $80 million of those proceeds to buyout an independent power producer contract. In January 2002, PSNH issued an additional $50 million in rate reduction bonds and used the proceeds from this issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December 2001. The majority of the payments to buyout or buydown these contracts were recorded as securitized regulatory assets. CL&P also securitized a portion of its SFAS No. 109 regulatory asset.

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 and WMECO was securitized in 2001 and is included in securitized regulatory assets. These remaining amounts for PSNH are recovered as stranded costs. During 2002, NU was notified by the Yankee Companies that the estimated cost of decommissioning their units had increased over prior estimates due to higher anticipated costs for spent fuel storage, security and liability and property insurance. In December 2002, NU recorded an additional $171.6 million in deferred contractual obligations and a corresponding increase in the unrecovered contractual obligations regulatory asset as a result of these increased costs.

CL&P, PSNH, WMECO, and NAEC, under the Energy Policy Act of 1992 (Energy Act), 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) when they owned nuclear generating plants. 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 are currently recovering these costs through rates. At December 31, 2002 and 2001, NU's total D&D Assessment deferrals were $21.9 million and $28.1 million, respectively, and have been recorded as recoverable energy costs, net.

Through December 31, 1999, CL&P had an energy adjustment clause under which fuel prices above or below base-rate levels were charged to or credited to customers. CL&P's energy costs deferred and not yet collected under the energy adjustment clause amounted to $31.7 million and $59 million at December 31, 2002 and 2001, respectively, which have been recorded as recoverable energy costs, net. On July 26, 2001, the Connecticut Department of Public Utility Control (DPUC) authorized CL&P to assess a charge of approximately $0.002 per kilowatt-hour (kWh) from August 2001 through December 2003 to collect these costs. 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, 2002 and 2001, PSNH had $179.6 million and $183.3 million, respectively, of recoverable energy costs deferred under the FPPAC, including previous deferrals of purchases from independent power producers. 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 costs associated with certain contractual purchases from independent power producers that had previously been included in the FPPAC. These costs are treated as Part 3 stranded costs and amounted to $62.1 million and $68.1 million at December 31, 2002 and 2001, 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 in or refunded in future periods. These amounts are recorded as recoverable energy costs, net.

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, "Accounting for Income Taxes."

The tax effect of temporary differences, including timing differences accrued under previously approved accounting standards, that give rise to the accumulated deferred tax obligation is as follows:

(Millions of Dollars)	*At December 31,* 2002	2001
Accelerated depreciation and other plant-related differences	$ 493.7	$ 577.5
Regulatory assets:		
Nuclear stranded investment and other asset divestitures	270.9	324.6
Securitized contract termination costs and other	255.4	279.7
Income tax gross-up	194.6	190.0
Other	221.9	119.6
Totals	$1,436.5	$1,491.4

I. Cash and Cash Equivalents

Cash and cash equivalents includes cash on hand and short-term cash investments which are highly liquid in nature and have original maturities of three months or less.

J. Accounting for Competitive Energy Contracts

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

Nonderivative contracts that are entered into for the normal purchase or sale of energy to customers that will result in physical delivery are recorded at the point of delivery under accrual accounting. Derivative contracts that are entered into for the normal purchase and sale of energy and meet the "normal purchase and sale" exception to derivative accounting, as defined in SFAS No. 133, are also recorded at the point of delivery under accrual accounting.

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. Other contracts that are derivatives that do not qualify as normal purchases and sales or hedges are also recorded on the consolidated balance sheets at fair value with changes in fair value reflected in operating revenues for sales and fuel, purchased and net interchange power for purchases.

Revenues and expenses for derivative contracts that are not entered into for trading purposes are recorded at gross amounts when these transactions settle.

Competitive energy contracts that are hedging an underlying transaction and qualify as cash flow hedges are recorded on the consolidated balance sheets at fair value with changes in fair value generally reflected in 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 accounting for competitive energy contracts, see Note 3, "Derivative Instruments, Market Risk and Risk Management," to the consolidated financial statements.

K. Stock-Based Compensation

At December 31, 2002, NU maintains an Employee Stock Purchase Plan (ESPP) and other long-term incentive plans which are described more fully in Note 4D, "Employee Benefits – Stock-Based Compensation" to the consolidated financial statements. NU accounts for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-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 stock-based employee compensation.

(Millions of Dollars, except per share amounts)	For the Years Ended December 31, 2002	2001	2000
Net income/(loss), as reported	$152.1	$243.5	$(28.6)
Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effects	(5.3)	(4.4)	(5.3)
Pro forma net income/(loss)	$146.8	$239.1	$(33.9)
Earnings/(loss) per share:			
Basic – as reported	$ 1.18	$ 1.80	$(0.20)
Basic – pro forma	$ 1.14	$ 1.76	$(0.24)
Diluted – as reported	$ 1.18	$ 1.79	$(0.20)
Diluted – pro forma	$ 1.14	$ 1.76	$(0.24)

L. Other Income/(Loss), Net

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

(Millions of Dollars)	For the Years Ended December 31, 2002	2001	2000
Seabrook-related gains	$38.7	$ —	$ —
Investment write-downs	(18.4)	—	—
Gain related to Millstone sale	—	201.9	—
Loss on share repurchase contracts	—	(35.4)	—
Investment income	25.4	19.3	42.4
Other, net	(1.9)	1.8	(56.7)
Totals	$43.8	$187.6	$(14.3)

Other, net in 2000 primarily relates to nuclear related costs and adjustments to NU's environmental reserves.

M. Supplemental Cash Flow Information

In conjunction with the Yankee acquisition on March 1, 2000, common stock was issued and debt was assumed as follows (millions of dollars):

Fair value of assets acquired, net of liabilities assumed	$ 712.5
Debt assumed	(234.0)
NU common shares issued	(217.1)
Cash paid	$ 261.4

(Millions of Dollars)	For the Years Ended December 31, 2002	2001	2000
Cash paid during the year for:			
Interest, net of amounts capitalized	$259.9	$275.3	$269.7
Income taxes	$114.4	$321.0	$253.4

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. Currently, SEC authorization allows NU, CL&P, WMECO, and Yankee Gas to incur total short-term borrowings up to a maximum of $400 million, $375 million, $250 million, and $100 million, respectively. In addition, the charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. At December 31, 2002, CL&P's charter permits CL&P to incur $480 million of additional unsecured debt. PSNH is authorized by the New Hampshire Public Utilities Commission (NHPUC) to incur short-term borrowings up to a maximum of $100 million. Prior to the sale of Seabrook, NAEC had NHPUC authorization to incur short-term borrowings up to a maximum of $260 million. Currently, NAEC has no plans to incur any future short-term borrowings.

Regulated Companies Credit Agreement: On November 12, 2002, CL&P, PSNH, WMECO, and Yankee Gas entered into a 364-day unsecured revolving credit facility for $300 million. This facility replaced a $350 million facility for CL&P, PSNH, WMECO and Yankee Gas, which expired on November 15, 2002. CL&P may draw up to $150 million under the facility and PSNH, WMECO and Yankee Gas each may draw up to $100 million, subject to the $300 million maximum borrowing limit under the facility. Unless extended, the credit facility will expire on November 11, 2003. At December 31, 2002 and 2001, there were $7 million and $160.5 million, respectively, in borrowings under these facilities.

NU Parent Credit Agreement: NU replaced its $300 million 364-day unsecured revolving credit facility, which was to expire on November 15, 2002, with a 364-day unsecured revolving credit facility on November 12, 2002. This facility provides a total commitment of $350 million, which is available subject to two overlapping sub-limits. First, subject to the notional amount of any letters of credit outstanding, amounts up to $350 million are available for advances. Second, subject to the advances outstanding, letters of credit may be issued in notional amounts up to $250 million, an increase of $50 million over the prior facility in the name of NU or any of its subsidiaries. Unless extended, this credit facility will expire on November 11, 2003. At December 31, 2002 and 2001, there were $49 million and $40 million, respectively, in borrowings under these facilities. With regard to credit support, NU had $6.7 million and $45 million, respectively, in letters of credit issued under these facilities at December 31, 2002 and 2001.

NAEC Credit Agreement: On November 9, 2001, NAEC entered into an unsecured 364-day term credit agreement for $90 million. The term credit agreement contained a mandatory prepayment provision requiring 100 percent prepayment of the aggregate amount outstanding within two days of the sale of Seabrook. On November 1, 2002, NAEC consummated the sale of its ownership interest in Seabrook and repaid its $90 million in borrowings under this credit agreement. The agreement expired on November 8, 2002. At December 31, 2001, there were $90 million in borrowings under this term credit agreement.

Under the aforementioned 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, 2002 and 2001, were 4.25 percent and 3.38 percent, respectively.

These credit agreements provide that NU and its subsidiaries must comply with certain financial and nonfinancial covenants as are customarily included in such agreements, including, but not limited to, consolidated debt ratios and interest coverage ratios. The parties to the credit agreements currently are and expect to remain in compliance with these covenants.

Guarantees: NU provides credit assurance in the form of guarantees and letters of credit in the normal course of business for the financial performance obligations of certain of its competitive energy subsidiaries of which most are revocable with no term specifications. NU would be required to perform under these guarantees in the event of non-performance under these obligations by the competitive energy subsidiaries. NU currently has authorization from the SEC to provide up to $500 million of guarantees through September 30, 2003, and has applied for authority to increase this amount to $750 million. At December 31, 2002, payments guaranteed by NU, primarily on behalf of its competitive businesses, totaled $183.1 million. Additionally, NU had $6.7 million of letters of credit outstanding at December 31, 2002 and in conjunction with its investment in RMS, NU guarantees a $3 million line of credit through 2005. Also, in conjunction with its investment in SESI, NU guarantees up to $30 million of SESI debt under arrangements with a third-party financing of long-term receivables.

3. Derivative Instruments, Market Risk and Risk Management

A. Derivative Instruments

Effective January 1, 2001, NU adopted SFAS No. 133, as amended. 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 that are entered into as a normal purchase or sale and will result in physical delivery, and are documented as such, are recorded under accrual accounting. For information regarding accounting changes related to trading activities, see Note 1C, "Summary of Significant Accounting Policies – New Accounting Standards," to the consolidated financial statements.

During 2002, a positive $17 million, net of tax, was reclassified from other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized in earnings. An additional $0.9 million, net of tax, was recognized in earnings for those derivatives that were determined to be ineffective and for the ineffective portion of cash flow hedges. Also during 2002, new cash flow hedge transactions were entered into which hedge cash flows through 2005. As a result of these new transactions and market value changes since January 1, 2002, other comprehensive income increased by $52.4 million, net of tax. Accumulated other comprehensive income at December 31, 2002, was a positive $15.5 million, net of tax (increase to equity), relating to hedged transactions, and it is estimated that $9.3 million of this balance, net of tax, will be reclassified as an increase to earnings within the next twelve months. Cash flows from the hedge contracts are reported in the same category as cash flows from the underlying hedged transaction.

There have been changes to interpretations of SFAS No. 133, and the FASB continues to consider changes and amendments which could affect the way NU records and discloses derivative and hedging activities in the future.

During 2001, a positive $4.5 million, net of tax, was reclassified from other comprehensive income in connection with the consummation of the underlying hedged transactions and recognized in earnings. An additional $1.3 million, net of tax, was recognized in earnings for those derivatives that were determined to be ineffective and for the ineffective portion of cash flow hedges. Also during 2001, new cash flow hedge transactions were entered into which hedge cash flows through 2027. As a result of these new transactions and market value changes since January 1, 2001, other comprehensive income decreased by $36.9 million, net of tax. Accumulated other comprehensive income at December 31, 2001, was a negative $36.9 million, net of tax (decrease to equity), relating to hedged transactions, and it is estimated that $29.4 million of this balance, net of tax, will be reclassified as a decrease to earnings within the next twelve months. Cash flows from the hedge contracts are reported in the same category as cash flows from the underlying hedged transaction.

The tables below summarize the derivative assets and liabilities at December 31, 2002 and 2001. These amounts do not include premiums paid, which are recorded as prepayments and amounted to $26.6 million and $8.3 million at December 31, 2002 and 2001, respectively. These amounts also do not include premiums received, which are recorded as liabilities and amounted to $29.5 million and $44.2 million at December 31, 2002 and 2001, respectively. These amounts relate primarily to energy trading activities.

(Millions of Dollars)	*At December 31, 2002*		
	Assets	*Liabilities*	*Total*
Competitive Energy Subsidiaries:			
Trading	$102.9	$(61.9)	$41.0
Nontrading	2.9	—	2.9
Hedging	22.8	(2.0)	20.8
Regulated Gas Utility:			
Hedging	2.3	—	2.3
Total	$130.9	$(63.9)	$67.0

(Millions of Dollars)	*At December 31, 2001*		
	Assets	*Liabilities*	*Total*
Competitive Energy Subsidiaries:			
Trading	$147.2	$ (90.8)	$56.4
Hedging	2.9	(58.4)	(55.5)
Regulated Gas Utility:			
Hedging	0.2	(2.3)	(2.1)
NU Parent:			
Hedging	—	(0.1)	(0.1)
Total	$150.3	$(151.6)	$ (1.3)

Competitive Energy Subsidiaries Trading: As a market participant in the Northeast United States, Select Energy conducts 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 exposure. 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, 2002 and 2001 were assets of $41 million and $56.4 million, respectively.

The competitive energy subsidiaries trading portfolio includes New York Mercantile Exchange (NYMEX) futures and options, the fair value of which is based on closing exchange prices; over-the-counter forwards and options, the fair value of which is based on the mid-point of bid and ask quotes; and bilateral contracts for the purchase or sale of electricity or natural gas, the fair value of which is modeled using available information from external sources based on recent transactions and validated with a gas forward curve and an estimated heat rate conversion. The competitive energy subsidiaries trading portfolio also includes transmission congestion contracts. The fair value of certain transmission congestion contracts is based on market inputs. Market information for other transmission congestion contracts is not available, and those contracts cannot be reliably valued. Management believes the amounts paid for these contracts are equal to their fair value and has established a valuation reserve for changes in fair value in excess of cost.

Management conducted a thorough review of the contracts in the trading portfolio in order to adopt EITF Issue No. 02-3 as of October 1, 2002. Based on this review, the significant changes in the energy trading market, and the change in the focus of the energy trading business, certain long-term derivative energy contracts that were previously included in the trading portfolio and valued at $33.9 million as of November 30, 2002 were determined to be nontrading and subsequently designated as normal purchases and sales, as defined by SFAS No. 133, as of that date. Management was able to make this designation based on the high probability that these contracts will result in physical delivery. The impact of the normal purchases and sales designation is that these contracts were adjusted to fair value as of November 30, 2002 and were not and will not be adjusted subsequently for changes in fair value. The $33.9 million carrying value as of November 30, 2002 was reclassified from trading derivative assets to other long-term assets and will be amortized on a straight-line basis to fuel, purchased and net interchange power expense over the remaining terms of the contracts, which extend to 2011.

Competitive Energy Subsidiaries Nontrading: Nontrading derivative contracts are for delivery of energy related to the competitive energy subsidiaries' retail and wholesale marketing activities. These contracts are not entered into for trading purposes, but are subject to fair value accounting because these contracts are derivatives that cannot be designated as normal purchases or sales, as defined by SFAS No. 133. These contracts cannot be designated as normal purchases or sales either because they are included in the New York energy market that settles financially or because the normal purchase and sale designation was not elected by management. The fair value of nontrading derivatives was an asset of $2.9 million at December 31, 2002. The competitive energy subsidiaries held no nontrading derivatives at December 31, 2001.

Competitive Energy Subsidiaries 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 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 retail supply 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, natural gas, or oil. 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 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 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 2004. Select Energy has hedged its gas supply risk under these agreements through NYMEX futures contracts. Under these contracts, which also extend through 2004, the purchase price of a specified quantity of gas is effectively fixed over the term of the gas service agreements. At December 31, 2002 and 2001, the NYMEX futures contracts had notional values of $30.9 million and $91.3 million, respectively, and were recorded at fair value as a derivative asset of $12.2 million at December 31, 2002, and as a derivative liability of $24.5 million at December 31, 2001.

During 2002, Select Energy determined that cash flow hedges related to the CL&P standard offer service contract were ineffective. These hedges were natural gas derivatives that were used to hedge off-peak electricity purchases for CL&P standard offer sales. As a result of this ineffectiveness, Select Energy transferred $3.9 million related to these cash flow hedges from accumulated other comprehensive income to fuel, purchased and net interchange power expense. Also in 2002, Select Energy terminated these cash flow hedges and realized pre-tax income of $5.6 million. In 2001, Select Energy had a liability related to these standard offer contract hedges of $31.3 million with a corresponding accumulated other comprehensive loss.

In the fourth quarter of 2002, Select Energy designated new hedges with a derivative asset value of $5.6 million as hedging full requirements contracts in the New York market.

Regulated Gas Utility 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 two unaffiliated customers is effectively fixed over the term of the gas service agreements with those customers for a period of time not extending beyond 2005. At December 31, 2002 and 2001, the commodity swap agreement had notional values of $10.7 million and $16.9 million, respectively, and was recorded at fair value as a derivative asset of $2.3 million at December 31, 2002, and as a derivative liability of $2.3 million at December 31, 2001.

In 2001 Yankee Gas also held two interest rate swaps with a fair value derivative asset amount of $0.2 million. These swaps were terminated in 2002.

NU Parent Hedging: At December 31, 2001, NU Parent maintained a treasury interest rate lock agreement, which was recorded as a fair value liability of $0.1 million. This agreement was terminated in 2002.

B. 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.

Competitive Energy Subsidiaries Trading Portfolio: At December 31, 2002, Select Energy has calculated the market price resulting from a 10 percent unfavorable change in forward market prices. That 10 percent change would result in approximately a $2.6 million decline in the fair value of the Select Energy trading portfolio. In the normal course of business, Select Energy also faces risks that are either nonfinancial or non-quantifiable. Such risks principally include credit risk, which is not reflected in this sensitivity analysis.

Competitive Energy Subsidiaries Retail and Wholesale Marketing Portfolio: When conducting sensitivity analyses of the change in the fair value of Select Energy's electricity, natural gas and oil nontrading derivatives 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 account 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 retail and wholesale marketing portfolio, which includes cash flow hedges and electricity, natural gas and oil contracts, assuming a 10 percent unfavorable change in forward market prices. At December 31, 2002, an unfavorable 10 percent change in market price would have resulted in a decline in fair value of approximately $4.4 million.

The impact of a change in electricity, natural gas and oil prices on Select Energy's retail and wholesale marketing portfolio at December 31, 2002, is not necessarily representative of the results that will be realized when these contracts are physically delivered.

C. Other Risk Management Activities

Interest Rate Risk Management: NU manages its interest rate risk exposure by maintaining a mix of fixed and variable rate debt. At December 31, 2002, approximately 79 percent of NU's long-term debt, including the current portion and fees and interest due for spent nuclear fuel disposal costs, is at a fixed interest rate. Fixed interest rate debt is subject to interest rate risk in a falling interest rate environment. 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, annual interest expense would have increased by $4.9 million. At December 31, 2002, NU does not have any derivative contracts outstanding to manage interest rate risk.

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 their contractual obligations. NU serves a wide variety of customers and suppliers that include independent power producers, 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.

NU's regulated utilities have a lower level of credit risk related to providing electric and gas distribution service than NU's competitive energy subsidiaries.

Credit risks and market risks at the competitive energy subsidiaries are monitored regularly by a Risk Oversight Council operating outside of the business units 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 are guaranteed by the NYMEX and have a lower credit risk. 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 conditions (including credit ratings), collateral requirements under certain circumstances (including cash in advance, letters of credit, 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 NU entering into trading activities. The appropriateness of these limits is subject to continuing review. Concentrations among these counterparties may impact NU'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.

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 (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 income, approximately 30 percent of which was credited to utility plant, was $73.4 million in 2002, $101 million in 2001, and $90.9 million in 2000. These amounts exclude pension settlements, curtailments and net special termination income of $22.2 million in 2002, expense of $2.6 million in 2001, and income of $7 million in 2000.

Pension income attributable to earnings is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2002	2001	2000
Pension income before settlements, curtailments and special termination benefits	$(73.4)	$(101.0)	$(90.9)
Net pension income capitalized as utility plant (a)	22.0	30.3	27.3
Net pension income before settlements, curtailments and special termination benefits	(51.4)	(70.7)	(63.6)
Settlements, curtailments and special termination benefits reflected in earnings	—	7.5	—
Total pension income included in earnings	$(51.4)	$ (63.2)	$(63.6)

(a) *Net pension income capitalized as utility plant was calculated utilizing an average of 30 percent.*

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. 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 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 and $6.6 million of curtailment income and $0.4 million of special termination benefits income in 2000.

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 NU's 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 NU's 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.

In conjunction with the Voluntary Separation Program (VSP) that was announced in December 2000, NU recorded $26 million in settlement income and $64.7 million in curtailment income in 2001. The VSP was intended to reduce the generation-related support staff between March 1, 2001 and February 28, 2002, and was available to non-bargaining unit employees who, by February 1, 2002, were at least age 50, with a minimum of five years of credited service, and at December 15, 2000, were assigned to certain groups and in eligible job classifications.

One component of the VSP included special pension termination benefits equal to the greater of five years added to both age and credited service of eligible participants or two weeks of pay for each year of service subject to a minimum level of 12 weeks and a maximum of 52 weeks for eligible participants. The special pension termination benefits expense associated with the VSP totaled $93.3 million in 2001. The net total of the settlement and curtailment income and the special termination benefits expense was $2.6 million, of which $7.5 million of costs were included in operating expenses, $5.1 million was deferred as a regulatory liability and is expected to be returned to customers and $0.2 million was billed to the joint owners of Millstone and Seabrook.

Postretirement Benefits Other Than Pensions (PBOP): NU's subsidiaries also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees. 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 annually funds postretirement costs through external trusts with amounts that have been rate-recovered and which also are tax deductible.

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. In 2001, NU recorded PBOP curtailment expense and special termination benefits expense totaling $11.9 million in connection with the VSP. This amount was recorded as a regulatory asset and collected through regulated utility rates in 2002.

Additionally, in conjunction with the divestiture of its generation assets, NU recorded $0.4 million in special termination benefits income in 2000.

In 2002, the PBOP plan was amended to change the claims experience basis, to increase minimum retiree contributions and to reduce the cap on the company's subsidy to the dental plan. These amendments resulted in a $34.2 million decrease in NU's benefit obligation under the PBOP plan at December 31, 2002.

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

(Millions of Dollars)	*At December 31,* Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
Change in benefit obligation				
Benefit obligation at beginning of year	$(1,687.6)	$(1,670.9)	$(400.0)	$(335.3)
Service cost	(37.2)	(35.7)	(6.2)	(6.2)
Interest cost	(119.8)	(119.7)	(29.2)	(27.2)
Plan amendment	(11.4)	—	34.2	—
Actuarial loss	(117.7)	(72.1)	(44.0)	(76.2)
Benefits paid – excluding lump sum payments	97.3	94.5	44.0	38.0
Benefits paid – lump sum payments	50.2	133.8	—	—
Curtailments and settlements	44.5	75.8	3.4	6.9
Special termination benefits	(8.1)	(93.3)	—	—
Benefit obligation at end of year	$(1,789.8)	$(1,687.6)	$(397.8)	$(400.0)
Change in plan assets				
Fair value of plan assets at beginning of year	$ 1,990.4	$ 2,319.4	$ 171.1	$ 197.6
Actual return on plan assets	(213.1)	(100.7)	(14.4)	(17.1)
Employer contribution	—	—	35.0	28.6
Plan asset transfer in	2.5	—	—	—
Benefits paid – excluding lump sum payments	(97.3)	(94.5)	(44.0)	(38.0)
Benefits paid – lump sum payments	(50.2)	(133.8)	—	—
Fair value of plan assets at end of year	$ 1,632.3	$ 1,990.4	$ 147.7	$ 171.1
Funded status at December 31	$ (157.5)	$ 302.8	$(250.1)	$(228.9)
Unrecognized transition (asset)/obligation	(2.6)	(3.6)	118.5	159.1
Unrecognized prior service cost	70.1	72.8	(5.9)	—
Unrecognized net loss/(gain)	418.9	(139.6)	124.8	55.4
Prepaid/(accrued) benefit cost	$ 328.9	$ 232.4	$ (12.7)	$ (14.4)

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

	At December 31, Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Compensation/progression rate	4.00%	4.25%	4.00%	4.25%
Health care cost trend rate (a)	N/A	N/A	10.00%	11.00%

(a) *The annual per capita cost of covered health care benefits was assumed to decrease to 5.00 percent by 2007.*

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

	For the Years Ended December 31,					
	Pension Benefits			*Postretirement Benefits*		
(Millions of Dollars)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
Service cost	$ 37.2	$ 35.7	$ 41.2	$ 6.2	$ 6.2	$ 6.8
Interest cost	119.8	119.7	118.5	29.2	27.2	23.7
Expected return on plan assets	(204.9)	(214.1)	(205.1)	(16.6)	(17.0)	(14.1)
Amortization of unrecognized net transition (asset)/obligation	(1.4)	(1.5)	(1.4)	13.6	14.5	15.1
Amortization of prior service cost	7.7	6.9	7.9	(0.1)	—	—
Amortization of actuarial gain	(31.8)	(47.7)	(52.0)	—	—	—
Other amortization, net	—	—	—	2.2	(2.6)	(4.3)
Net periodic (income)/expense – before settlements, curtailments and special termination benefits	(73.4)	(101.0)	(90.9)	34.5	28.3	27.2
Settlement income	—	(26.0)	—	—	—	—
Curtailment (income)/expense	(30.3)	(64.7)	(6.6)	—	3.3	—
Special termination benefits expense/(income)	8.1	93.3	(0.4)	(1.2)	8.6	(0.4)
Total – settlements, curtailments and special termination benefits	(22.2)	2.6	(7.0)	(1.2)	11.9	(0.4)
Total – net periodic (income)/expense	$ (95.6)	$ (98.4)	$(97.9)	$ 33.3	$ 40.2	$ 26.8

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*		
	2002	*2001*	*2000*	*2002*	*2001*	*2000*
Discount rate	7.25%	7.50%	7.75%	7.25%	7.50%	7.75%
Expected long-term rate of return	9.25%	9.50%	9.50%	N/A	N/A	N/A
Compensation/progression rate	4.25%	4.50%	4.75%	4.25%	4.50%	4.75%
Long-term rate of return –						
Health assets, net of tax	N/A	N/A	N/A	7.25%	7.50%	7.50%
Life assets	N/A	N/A	N/A	9.25%	9.50%	9.50%

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	$ 0.9	$ (0.8)
Effect on postretirement benefit obligation	$12.2	$(11.0)

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.

Pension and trust assets are invested primarily in domestic and international equity securities and bonds.

The trust holding the health plan assets is 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 3 percent of eligible compensation with cash and NU shares. The matching contributions made by NU were $11.1 million in 2002, $11.7 million in 2001, and $13.6 million in 2000.

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 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 on the ESOP notes at the same rate that ESOP shares are allocated to employees. NU makes annual contributions to the ESOP equal to the ESOP's debt service, less dividends received by the ESOP. 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 2001, NU declared a $0.10 per share quarterly dividend. During the third quarter of 2001 through the second quarter of 2002, NU declared a $0.125 per share quarterly dividend. NU declared a $0.1375 per share dividend during the third and fourth quarters of 2002.

In 2002 and 2001, the ESOP trust issued 607,475 and 546,610 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. At December 31, 2002 and 2001, total allocated ESOP shares were 7,008,784 and 6,401,309, respectively, and total unallocated ESOP shares were 3,791,401 and 4,398,876, respectively. The fair market value of unallocated ESOP shares at December 31, 2002 and 2001, was $57.5 million and $77.6 million, respectively.

D. Stock-Based Compensation

Employee Share Purchase Plan: Since July 1998, NU has maintained an ESPP for all eligible employees. Under the ESPP, NU common shares were 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. Effective January 1, 2001, the ESPP was terminated because of a pending merger. In the second quarter of 2001, a new ESPP was adopted by NU's Board of Trustees and approved by NU's shareholders. During 2002, employees purchased 188,774 shares at discounted prices of $14.15 and $15.39. At December 31, 2002, 1,811,226 shares remained registered for future issuance under the ESPP.

Incentive Plans: NU has long-term incentive plans authorizing various types of awards, including stock options and performance units, to be made to eligible employees and board members. The exercise price of stock options, as set at the time of grant, is equal to the fair market value per share at the date of grant, and therefore no stock-based compensation cost is reflected in net income. A liability of $1.3 million was recorded at December 31, 2002, for the fair value of the performance units earned. Under the Northeast Utilities Incentive Plan (Incentive Plan), the number of shares which may be utilized for or made subject to issuance pursuant to grants and awards granted 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, 2002 and 2001, NU had 2,440,339 and 2,692,633 shares of common stock, respectively, registered for issuance under the Incentive Plan.

Stock option transactions for 2002, 2001 and 2000, including those options acquired in connection with the Yankee merger, are as follows:

		Exercise Price Per Share	
	Options	*Range*	*Weighted Average*
Outstanding – December 31, 1999	1,826,256	$ 9.6250 – $ 21.1250	$ 14.0585
Granted	669,470	$18.4375 – $ 22.2500	$ 18.7029
Yankee merger	10,167	$ 9.3640 – $ 12.6888	$ 10.7653
Exercised	(43,750)	$14.9375 – $ 19.5000	$ 16.0658
Forfeited and cancelled	(28,281)	$14.9375 – $ 19.5000	$ 16.6515
Outstanding – December 31, 2000	2,433,862	$ 9.3640 – $ 22.2500	$ 15.2569
Granted	817,300	$17.4000 – $ 21.0300	$ 20.2065
Exercised	(108,779)	$ 9.3640 – $ 19.5000	$ 16.0970
Forfeited and cancelled	(132,467)	$14.8750 – $ 21.0300	$ 18.2217
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**
Exercisable – December 31, 2000	1,298,339	$ 9.3640 – $ 22.2500	$ 14.2021
Exercisable – December 31, 2001	1,712,260	$ 9.6250 – $ 22.2500	$ 14.4650
Exercisable – December 31, 2002	**1,956,555**	**$ 9.6250 – $22.2500**	**$15.3758**

In 1997, 500,000 options with a weighted average exercise price of $9.625 were granted. These options, which are all exercisable at December 31, 2002, have a remaining contractual life of 4.63 years. Excluding these options from those outstanding at December 31, 2002, the resulting range of exercise prices is $14.9375 to $22.25.

For certain options that were granted in 2002, 2001 and 2000, the vesting schedule for these options is ratably over three years from the date of grant. Additionally, certain options granted in 2002, 2001 and 2000 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.

NU has also made several small grants of restricted stock and other incentive-based stock compensation under the Incentive Plan. During 2002, 2001 and 2000, $1 million, $1.2 million and $1.9 million, respectively, was expensed related to this stock-based compensation.

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:

	2002	*2001*	*2000*
Risk-free interest rate	**4.86%**	5.34%	6.56%
Expected life	**10 years**	10 years	10 years
Expected volatility	**23.71%**	25.47%	26.15%
Expected dividend yield	**2.11%**	2.11%	1.82%

The weighted average grant date fair values of options granted during 2002, 2001 and 2000 were $5.64, $6.94 and $7.50, respectively. The weighted average remaining contractual lives for those options outstanding at December 31, 2002 and 2001 are 7.50 years.

For further information regarding stock-based compensation, see Note 1C, "Summary of Significant Accounting Policies – New Accounting Standards," and Note 1K, "Summary of Significant Accounting Policies – Stock-Based Compensation," to the consolidated financial statements.

E. Supplemental Executive Retirement and Other Plans

NU has maintained a Supplemental Executive Retirement Plan (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 $20.1 million and $18 million at December 31, 2002 and 2001, respectively, represents NU's actuarially determined obligation under the SERP. For information regarding the SERP investments, see Note 9, "Fair Value of Financial Instruments," to the consolidated financial statements.

NU maintains a plan for retirement and other benefits for certain current and past company officers. The actuarially determined liability for this plan was $32.2 million and $25.2 million at December 31, 2002 and 2001, respectively.

5. Goodwill and Other Intangible Assets

Effective January 1, 2002, NU adopted SFAS No. 142, "Goodwill and Other Intangible Assets," which ceases amortization of goodwill and certain intangible assets with indefinite useful lives. SFAS No. 142 also requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment upon adoption of SFAS No. 142 and at least annually thereafter by applying a fair value-based test. Under SFAS No. 142, 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.

On July 1, 2002, the competitive energy subsidiaries acquired certain assets and assumed certain liabilities of Woods Electrical, an electrical services company and Woods Network, a network products and services company, for an aggregate adjusted purchase price of $16.3 million. The aggregate adjusted purchase price consisted of $4.2 million of tangible net assets, $0.1 million of intangible assets subject to amortization, consisting of customer backlog and employment related agreements, $6.8 million of indefinite lived intangible assets not subject to amortization consisting of $3.8 million associated with customer relationships acquired and $3 million associated with tradenames acquired, and $5.2 million of goodwill. The customer backlog and employment related agreements are being amortized over periods of one and three years, respectively, and have a weighted average amortization period of 1.6 years. This purchase price allocation is preliminary and has been adjusted since the acquisition date. Financial results of the acquired companies are included in NU's results of operations since July 1, 2002. The goodwill recognized in these transactions in the aggregate amount of $5.2 million was assigned to the competitive energy subsidiaries reportable segment and is expected to be fully deductible for tax purposes. Additionally, as part of these purchase agreements, an additional payment of not more than $9.2 million would be contingently payable by 2005 if certain earnings targets are met. Any contingent payments made will be accounted for as part of the purchase price.

NU's reporting units that maintain goodwill are generally consistent with the operating segments underlying the reportable segments identified in Note 13, "Segment Information," to the consolidated financial statements. During the fourth quarter of 2002, consistent with changes in the way management reviews the operating results of its reporting units, NU's reporting units under the competitive energy subsidiaries reportable segment were revised to include: 1) the wholesale marketing reporting unit, 2) the retail marketing reporting unit, 3) the trading reporting unit, and 4) the services reporting unit. The wholesale marketing, retail marketing and trading reporting units are comprised of the operations of Select Energy, NGC and HWP, and the services reporting unit is comprised of the operations of SESI, NGS and its newly acquired subsidiary Woods Electrical, Woods Network, and the nonenergy related subsidiaries of Yankee, including YESCO. As a result, NU's revised reporting units that maintain goodwill are as follows: Yankee Gas, classified under the regulated utilities – gas reportable segment, the wholesale and retail marketing reporting unit and the services reporting unit which are both classified under the competitive energy subsidiaries reportable segment. The goodwill balances of these reporting units are included in the table herein.

On November 30, 2001, Select Energy acquired Niagara Mohawk Energy Marketing, Inc. (NMEM) for $31.7 million. NMEM was subsequently renamed Select Energy New York, Inc. (SENY). During 2002, as a result of subsequent adjustments to SENY's purchase price allocation as a result of changes in the fair value of the assets and liabilities acquired, $3.2 million of goodwill was recorded. This goodwill amount is included in the wholesale and retail marketing reporting unit at December 31, 2002.

NU has completed its initial and subsequent impairment analyses, on January 1, 2002 and October 1, 2002, respectively, for all reporting units that maintain goodwill under SFAS No. 142. YESCO holds a note from an entity that purchased certain YESCO assets. Cash flows for YESCO support the investment but not the goodwill recorded.

As a result, in 2002, a goodwill impairment loss totaling $0.4 million was recognized in the services reporting unit. For all other reporting units, NU 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. Except for the aforementioned acquisitions and YESCO impairment, there were no other impairments or adjustments to these goodwill balances in 2002.

Inclusive of the aforementioned acquisitions and the YESCO goodwill write-off, at December 31, 2002, NU maintained $321 million of goodwill that is no longer being amortized, $18.1 million of identifiable intangible assets which continue to be amortized over an average period of 8.5 years and $6.8 million of intangible assets not subject to amortization. Primarily based on revised financial information, the remaining period of amortization related to the exclusivity agreement and the customer list were reduced from 15 years to 8.5 years during the fourth quarter of 2002, resulting in a prospective increase to amortization expense related to these intangible assets of $2 million annually. At December 31, 2001, NU maintained $313 million of goodwill and $20.1 million of identifiable intangible assets. Amortization of goodwill ceased on January 1, 2002.

These amounts are included on the consolidated balance sheets as goodwill and other purchased intangible assets, net. A summary of NU's goodwill balances at December 31, 2002 and 2001, by reportable segment and reporting unit is as follows:

(Millions of Dollars)	*At December 31, 2002*	*2001*
Regulated Utilities – Gas:		
Yankee Gas	$287.6	$287.6
Competitive Energy Subsidiaries:		
Services	30.2	25.4
Wholesale and Retail Marketing	3.2	—
Totals	$321.0	$313.0

At December 31, 2002 and December 31, 2001, NU's intangible assets and related accumulated amortization consisted of the following:

	At December 31, 2002		
(Millions of Dollars)	*Gross Balance*	*Accumulated Amortization*	*Net Balance*
Intangible assets subject to amortization:			
Exclusivity agreement	$17.7	$4.6	$13.1
Customer list	6.6	1.7	4.9
Customer backlog and employment related agreements	0.1	—	0.1
Totals	$24.4	$6.3	$18.1
Intangible assets not subject to amortization:			
Customer relationships	$ 3.8		
Trade names	3.0		
Totals	$ 6.8		

	At December 31, 2001		
(Millions of Dollars)	*Gross Balance*	*Accumulated Amortization*	*Net Balance*
Intangible assets subject to amortization:			
Exclusivity agreement	$17.7	$3.1	$14.6
Customer list	6.6	1.1	5.5
Totals	$24.3	$4.2	$20.1

NU recorded amortization expense of $2.1 million and $1.6 million for the years ended December 31, 2002 and 2001, respectively, related to these intangible assets. Based on the current amount of intangible assets subject to amortization, the estimated annual amortization expense for each of the succeeding 5 years from 2003 through 2007 is $3.7 million in 2003 and $3.6 million in subsequent years. These amounts may vary as purchase price allocations are finalized and acquisitions and dispositions occur in the future.

The results for the years ended December 31, 2001 and 2000, on a historical basis, do not reflect the provisions of SFAS No. 142. Had NU adopted SFAS No. 142 on January 1, 2000, historical income before the cumulative effect of an accounting change and extraordinary loss, net income and basic and fully diluted EPS amounts would have been adjusted as follows:

(Millions of Dollars, except share information)	*Net Income*	*Basic EPS*	*Fully Diluted EPS*
Year Ended December 31, 2002	$152.1	$1.18	$1.18
Year Ended December 31, 2001:			
Reported income before cumulative effect of accounting change	$ 265.9	$ 1.97	$ 1.96
Add back: goodwill amortization	9.0	0.07	0.07
Adjusted income before cumulative effect of accounting change	$ 274.9	$ 2.04	$ 2.03
Reported net income	$ 243.5	$ 1.80	$ 1.79
Add back: goodwill amortization	9.0	0.07	0.07
Adjusted net income	$ 252.5	$ 1.87	$ 1.86
Year Ended December 31, 2000:			
Reported income before extraordinary loss	$ 205.3	$ 1.45	$ 1.45
Add back: goodwill amortization	7.5	0.05	0.05
Adjusted income before extraordinary loss	$ 212.8	$ 1.50	$ 1.50
Reported net loss	$ (28.6)	$(0.20)	$(0.20)
Add back: goodwill amortization	7.5	0.05	0.05
Adjusted net loss	$ (21.1)	$(0.15)	$(0.15)

6. Sale of Customer Receivables

At December 31, 2002, CL&P had sold accounts receivable of $40 million to a subsidiary of Citigroup, Inc. with limited recourse through the CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. Additionally, at December 31, 2002, $3.8 million of assets were designated as collateral and restricted under the agreement with the CRC and included in the consolidated balance sheets as cash and cash equivalents. 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, 2002, amounts sold to CRC from CL&P but not sold to the Citgroup, Inc. subsidiary totaling $178.9 million are included in investments in securitizable assets on the consolidated balance sheets. No amounts were sold in 2001.

7. 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 15 percent 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 will be used to pay approximately $95 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. In connection with the sale, NAEC and CL&P recorded a gain 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 this 15 percent ownership interest. The agreement also limited any top-off amount required to be funded by Baycorp for decommissioning as part of the sale process. NU received approximately $17 million in the fourth quarter of 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), net.

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. 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.

Millstone: On March 31, 2001, CL&P and WMECO consummated the sale of Millstone 1 and 2 to a subsidiary of Dominion Resources, Inc. (Dominion). CL&P, PSNH and WMECO sold their ownership interests in Millstone 3 to Dominion along with all of the unaffiliated joint ownership interests in Millstone 3. NU received approximately $1.2 billion of cash proceeds from the sale and applied the proceeds to taxes and reductions of debt and equity at CL&P, PSNH and WMECO. As part of the sale, Dominion assumed responsibility for decommissioning the three Millstone units. In connection with the sale, CL&P and WMECO recorded a gain in the amount of $642 million, which was used to offset stranded costs. Additionally, NU recorded an after-tax gain of $115.6 million related to the prior settlement of Millstone 3 joint owner claims.

8. Commitments and Contingencies

A. Restructuring and Rate Matters

Connecticut: On September 27, 2001, CL&P filed its application with the DPUC for approval of the disposition of the proceeds in the amount of approximately $1.2 billion from the sale of the Millstone units to a subsidiary of Dominion. This application described and requested DPUC approval for CL&P's treatment of its share of the proceeds from the sale. In accordance with Connecticut's electric utility industry restructuring legislation, CL&P was required to utilize any gains from the Millstone sale to offset stranded costs. The DPUC's final decision regarding this application was received on February 27, 2003, and did not have a material impact on NU's 2002 results of operations.

New Hampshire: In July 2001, the NHPUC opened a docket to review the FPPAC costs incurred between August 2, 1999, and April 30, 2001. Under the Restructuring Settlement, FPPAC deferrals are recovered as a Part 3 stranded cost through the stranded cost recovery charge. On December 31, 2002, the NHPUC issued its final order allowing recovery of virtually all such costs.

On June 28, 2002, PSNH made its first stranded cost recovery charge reconciliation filing with the NHPUC for the period May 1, 2001, through December 31, 2001. This filing reconciles stranded cost revenues against actual stranded cost charges with any difference being credited against stranded costs or deferred for future recovery. Included in the stranded cost charges are the generation costs for the filing period. The generation costs included in this filing were subject to a prudence review by the NHPUC. In January 2003, PSNH entered into a settlement agreement with the Office of Consumer Advocate and the staff of the NHPUC which resolved all outstanding issues. In conjunction with the settlement agreement, the NHPUC staff recommended no disallowances resulting from their review of the outages at PSNH's generating plants. A final order approving the settlement agreement was issued by the NHPUC in February 2003. The NHPUC order approved PSNH's reconciliation of stranded costs as outlined within the settlement agreement and had no impact on PSNH's earnings.

Massachusetts: On March 30, 2001, WMECO filed its second annual stranded cost reconciliation with the Massachusetts Department of Telecommunications and Energy (DTE) for calendar year 2000. On March 29, 2002, WMECO filed its 2001 annual transition cost reconciliation with the DTE. This filing reconciled the recovery of stranded generation costs for calendar year 2001 and includes sales proceeds from WMECO's portion of the Millstone units, the impact of securitization and approximately a $13 million benefit to ratepayers from WMECO's nuclear performance-based ratemaking process.

WMECO and the office of the Massachusetts Attorney General reached a settlement resolving all transition charge issues for the 1998 through 2001 reconciliations. The DTE approved this settlement on December 27, 2002. The settlement had a positive impact of $9 million on WMECO 2002 pre-tax earnings.

B. Environmental Matters

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. As such, NU has active environmental auditing and training programs and believes it is substantially in compliance with the current laws and regulations.

However, the normal course of operations may involve activities and substances that expose NU to potential liabilities of which management cannot determine the outcome. Additionally, management cannot determine the outcome for liabilities that may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Management does not believe, however, that this will have a material impact on NU's consolidated financial statements.

Based upon currently available information for the estimated remediation costs at December 31, 2002 and 2001, the liability recorded by NU for its estimated environmental remediation costs amounted to $41.9 million and $46.2 million, respectively. These amounts include $28.1 million and $32.2 million at December 31, 2002 and 2001, respectively, for remediation of former manufactured gas plants.

PSNH and Yankee Gas have regulatory recovery mechanisms for environmental costs. Accordingly, regulatory assets have been recorded for certain environmental liabilities.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, 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), 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, 2002 and 2001, fees due to the DOE for the disposal of Prior Period Fuel were $253.6 million and $249.3 million, respectively, including interest costs of $171.5 million and $167.2 million, respectively.

Fees for nuclear fuel burned on or after April 7, 1983, are billed currently to customers and paid to the DOE on a quarterly basis. At December 31, 2002, as NU's ownership shares of Millstone and Seabrook have been sold, NU is no longer responsible for fees relating to current fuel burned at these facilities.

D. Nuclear Insurance Contingencies

In conjunction with the divestiture of Millstone in 2001 and Seabrook in 2002, NU terminated its nuclear insurance related to these plants, and NU has no further exposure for potential assessments related to Millstone and Seabrook. However, through its continuing association with Nuclear Electric Insurance Limited (NEIL) and CYAPC and VYNPC, NU is subject to potential retrospective assessments totaling $0.8 million under its respective NEIL insurance policies.

E. 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, operation and maintenance (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 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 $27.6 million in 2002, $25.3 million in 2001, and $24.9 million in 2000.

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 $278.3 million in 2002, $363.9 million in 2001, and $482.1 million in 2000. These amounts are for independent power producer 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.

Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of a specified quantity of gas in the normal course of business as part of its portfolio to meet its actual sales commitments. These contracts extend through 2006. The total cost of Yankee Gas' procurement portfolio, including these contracts, amounted to $158 million in 2002, $195.8 million in 2001, and $148.2 million in 2000.

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.

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

(Millions of Dollars)	*2003*	*2004*	*2005*	*2006*	*2007*
VYNPC	$ 30.8	$ 29.4	$ 27.1	$ 28.3	$ 27.4
Electricity Procurement Contracts	338.5	345.1	350.0	349.9	278.2
Gas Procurement Contracts	172.2	151.3	130.9	116.2	36.9
Hydro-Quebec	26.3	25.5	25.0	22.7	21.7
Totals	$567.8	$551.3	$533.0	$517.1	$364.2

Select Energy: Select Energy maintains long-term agreements to purchase energy in the normal course of business as part of its portfolio of resources to meet its actual or expected sales commitments. The aggregate amount of these purchase contracts was $4.3 billion at December 31, 2002 as follows:

(Millions of Dollars)	
Year	
2003	$3,302.0
2004	612.6
2005	290.1
2006	68.7
2007	69.2
Total	$4,342.6

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

F. Nuclear Decommissioning and Plant Closure Costs

In conjunction with the Millstone, Seabrook and VYNPC nuclear generation asset divestitures, the applicable liabilities and nuclear decommissioning trusts were transferred to the purchasers and the purchasers agreed to assume responsibility for decommissioning their respective units.

During 2002, NU, along with the other joint owners, were notified by the Yankee Companies that the estimated cost of decommissioning the units owned by CYAPC, YAEC and MYAPC increased in total by approximately $380 million over prior estimates due to higher anticipated costs for spent fuel storage, security and liability and property insurance. NU's share of this increase would total $171.6 million. Following rate cases to be filed by the Yankee Companies with the FERC, NU will seek recovery of the higher decommissioning costs from retail customers through the appropriate state regulatory agency. At December 31, 2002 and 2001, NU's remaining estimated obligations, for decommissioning for the units owned by CYAPC, YAEC and MYAPC, which have been shut down were $354.5 million and $216.6 million, respectively.

G. Consolidated Edison, Inc. Merger Litigation

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

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' October 13, 1999 Agreement and Plan of Merger, as amended and restated as of January 11, 2000 (the Merger Agreement). On March 12, 2001, NU filed suit against Con Edison in the United States District Court for the Southern District of New York (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 seeking damages for breach of contract, fraudulent inducement and negligent misrepresentation. Con Edison has claimed that it is entitled to recover a portion of the merger synergy savings estimated to have a net present value of in excess of $700 million. NU disputes both Con Edison's entitlement to any damages as well as its method of computing its alleged damages.

The companies have completed discovery in the litigation. Motions for summary judgment were argued before the District Court on February 4, 2002. No trial date has been set. At this stage of the litigation, management can predict neither the outcome of this matter nor its ultimate effect on NU.

For further information regarding this litigation, see NU's 2002 report on Form 10-K, Item 3, "Legal Proceedings."

9. 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: The carrying amounts approximate fair value due to the short-term nature of cash and cash equivalents.

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 $17.9 million and $7.4 million held for benefit of the SERP were recorded at their fair market values at December 31, 2002 and 2001, of $17.8 million and $9 million, respectively. For information regarding the SERP liabilities, see Note 4E, "Employee Benefits – Supplemental Executive Retirement and Other Plans" 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, 2002	
(Millions of Dollars)	*Carrying Amount*	*Fair Value*
Preferred stock not subject to mandatory redemption	$ 116.2	$ 84.0
Long-term debt –		
First mortgage bonds	771.0	810.0
Other long-term debt	1,577.2	1,597.8
Rate reduction bonds	1,899.3	2,080.6

	At December 31, 2001	
(Millions of Dollars)	*Carrying Amount*	*Fair Value*
Preferred stock not subject to mandatory redemption	$ 116.2	$ 62.4
Long-term debt –		
First mortgage bonds	795.9	847.2
Other long-term debt	1,552.1	1,554.6
Rate reduction bonds	2,018.4	2,061.8

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.

10. 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.

Capital lease rental payments charged to operating expense were $1.7 million in 2002, $13.1 million in 2001, and $50.1 million in 2000. Interest included in capital lease rental payments was $0.6 million in 2002, $4.7 million in 2001, and $11.6 million in 2000. Operating lease rental payments charged to expense were $7.8 million in 2002, $7 million in 2001, and $10.1 million in 2000.

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, 2002 are as follows:

(Millions of Dollars) *Year*	*Capital Leases*	*Operating Leases*
2003	$ 3.1	$ 23.1
2004	3.0	20.6
2005	2.8	18.4
2006	2.7	16.2
2007	2.6	9.8
After 2007	22.4	26.9
Future minimum lease payments	$36.6	$115.0
Less amount representing interest	19.8	
Present value of future minimum lease payments	$16.8	

11. Accumulated Other Comprehensive Income/(Loss)

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

(Millions of Dollars)	*December 31, 2001*	*Current Period Change*	*December 31, 2002*
Qualified cash flow hedging instruments	$(36.9)	$52.4	$15.5
Unrealized gains/(losses) on securities	5.0	(5.1)	(0.1)
Minimum pension liability adjustments	(0.6)	0.1	(0.5)
Accumulated other comprehensive (loss)/income	$(32.5)	$47.4	$14.9

(Millions of Dollars)	*December 31, 2000*	*Current Period Change*	*December 31, 2001*
Qualified cash flow hedging instruments	$ —	$(36.9)	$(36.9)
Unrealized gains on securities	2.4	2.6	5.0
Minimum pension liability adjustments	(0.6)	—	(0.6)
Accumulated other comprehensive income/(loss)	$1.8	$(34.3)	$(32.5)

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

(Millions of Dollars)	*2002*	*2001*	*2000*
Qualified cash flow hedging instruments	$(33.1)	$24.3	$ —
Unrealized gains/(losses) on securities	3.3	(1.9)	(0.2)
Minimum pension liability adjustments	—	—	—
Accumulated other comprehensive income/(loss)	$(29.8)	$22.4	$(0.2)

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, 2002*	*2001*
Balance at beginning of year	$(36.9)	$ —
Cumulative effect of adopting SFAS No. 133	—	12.3
Hedged transactions recognized into earnings	17.0	4.5
Change in fair value	29.2	(29.6)
Cash flow transactions entered into for the period	6.2	(24.1)
Net change associated with the current period hedging transactions	52.4	(36.9)
Total fair value adjustments included in accumulated other comprehensive income/(loss)	$ 15.5	$(36.9)

12. Earnings Per Share

EPS is computed based upon the weighted average number of common shares outstanding 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. The following table sets forth the components of basic and diluted EPS.

(Millions of Dollars, except share information)	*2002*	*2001*	*2000*
Income before preferred dividends of subsidiaries	$157.7	$273.2	$219.5
Preferred dividends of subsidiaries	5.6	7.3	14.2
Income before cumulative effect of accounting change and extraordinary loss	152.1	265.9	205.3
Cumulative effect of accounting change, net of tax benefit	—	(22.4)	—
Extraordinary loss, net of tax benefit	—	—	(233.9)
Net income/(loss)	$152.1	$243.5	$ (28.6)
Basic EPS common shares outstanding (average)	129,150,549	135,632,126	141,549,860
Dilutive effect of employee stock options	190,811	285,297	417,356
Fully diluted EPS common shares outstanding (average)	129,341,360	135,917,423	141,967,216
Basic earnings/(loss) per common share:			
Income before cumulative effect of accounting change and extraordinary loss	$ 1.18	$ 1.97	$ 1.45
Cumulative effect of accounting change, net of tax benefit	—	(0.17)	—
Extraordinary loss, net of tax benefit	—	—	(1.65)
Net income/(loss)	$ 1.18	$ 1.80	$ (0.20)
Fully diluted earnings/(loss) per common share:			
Income before cumulative effect of accounting change and extraordinary loss	$ 1.18	$ 1.96	$1.45
Cumulative effect of accounting change, net of tax benefit	—	(0.17)	—
Extraordinary loss, net of tax benefit	—	—	(1.65)
Net income/(loss)	$ 1.18	$ 1.79	$ (0.20)

13. Segment Information

NU is organized between regulated utilities (electric and gas since the March 1, 2000 acquisition of Yankee) and competitive energy subsidiaries based on the regulatory environment of each segment. The regulated utilities segment represents approximately 78 percent, 78 percent, and 85 percent of NU's total revenues for each of the three years in the period ended December 31, 2002, respectively, and primarily includes the operations of CL&P, PSNH and WMECO, whose complete financial statements are included in NU's combined report on Form 10-K. The regulated gas utilities segment includes the operations of Yankee Gas. The reclassification of trading revenues and expenses, which has been retroactively applied to 2001, resulted in an increase in these percentages from amounts reported in prior periods. Regulated utility 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.

On January 1, 2000, Select Energy began serving one half of CL&P's standard offer load for a four-year period through December 31, 2003, at fixed prices. Total Select Energy revenues from CL&P for CL&P's standard offer load and for other transactions with CL&P, represented approximately $631 million or 38 percent in 2002, approximately $648 million or 31 percent in 2001 and approximately $652 million or 34 percent in 2000, of total competitive energy subsidiaries' revenues. Total CL&P purchases from the competitive energy subsidiaries are eliminated in consolidation. Additionally, Select Energy revenues from NSTAR represented $277.3 million or 13 percent and $285.1 million or 15 percent of total competitive energy subsidiaries' revenues for the years ended December 31, 2001 and 2000, respectively. Beginning in 2002, Select Energy also provided basic generation service in the New Jersey market. Select Energy revenues related to these contracts represented $207.4 million or 12 percent of total competitive energy subsidiaries' revenues for the year ended December 31, 2002. No other individual customer represented in excess of 10 percent of the competitive energy subsidiaries revenues for 2002, 2001 and 2000.

Additionally, WMECO's purchases from Select Energy represented approximately $14 million and $4 million of total competitive energy subsidiaries' revenues in 2002 and 2001, respectively.

The competitive energy subsidiaries segment includes the operations of Select Energy, a corporation engaged in the trading, marketing, transportation, storage, and sale of energy commodities, at wholesale and retail, in designated geographical areas; NGC, a corporation that acquires and manages generation facilities; SESI, a provider of energy management, demand-side management and related consulting services for commercial, industrial and institutional electric companies and electric utility companies; NGS, including Woods Electrical, a corporation that maintains and services fossil or hydroelectric facilities and provides third-party electrical, mechanical, and engineering contracting services; HWP, a company engaged in the production of electric power; and Woods Network and the competitive energy subsidiaries of Yankee.

Other in the following table includes the results for Mode 1, an investor in fiber-optic communications network, the results of the nonenergy-related subsidiaries of Yankee and the company's investment in Accumentrics Corporation. Interest expense included in Other primarily relates to the debt of NU parent. Inter-segment eliminations of revenues and expenses are also included in Other.

(Millions of Dollars)	Regulated Utilities Electric	Gas	Competitive Energy Subsidiaries	Eliminations And Other	Total
For the Year Ended December 31, 2002					
Operating revenues	$3,778.1	$293.3	$1,669.8	$(524.9)	$ 5,216.3
Depreciation and amortization	(618.9)	(24.1)	(22.0)	(2.2)	(667.2)
Other operating expenses	(2,679.8)	(229.3)	(1,684.5)	511.2	(4,082.4)
Operating income/(loss)	479.4	39.9	(36.7)	(15.9)	466.7
Other income/(loss), net	42.1	(0.8)	(2.0)	4.5	43.8
Interest expense, net	(187.2)	(14.2)	(43.9)	(25.2)	(270.5)
Income tax (expense)/benefit	(121.7)	(7.3)	28.5	18.2	(82.3)
Preferred dividends	(5.6)	—	—	—	(5.6)
Net income/(loss)	$ 207.0	$ 17.6	$ (54.1)	$ (18.4)	$ 152.1
Total assets	$7,549.0	$963.0	$1,973.2	$(217.6)	$10,267.6
Total investments in plant	$ 380.6	$ 70.6	$ 23.2	$ 18.1	$ 492.5

(Millions of Dollars)	Regulated Utilities Electric	Gas	Competitive Energy Subsidiaries	Eliminations And Other	Total
For the Year Ended December 31, 2001					
Operating revenues	$4,282.7	$378.0	$2,074.8	$ (767.3)	$ 5,968.2
Depreciation and amortization	(1,619.3)	(33.3)	(10.4)	478.9	(1,184.1)
Other operating expenses	(2,171.9)	(294.6)	(2,019.5)	241.0	(4,245.0)
Operating income/(loss)	491.5	50.1	44.9	(47.4)	539.1
Other income, net	72.8	4.1	5.8	104.9	187.6
Interest expense, net	(199.3)	(14.0)	(42.9)	(23.4)	(279.6)
Income tax expense	(154.3)	(14.3)	(2.8)	(2.5)	(173.9)
Preferred dividends	(7.3)	—	—	—	(7.3)
Income before cumulative effect of accounting change	203.4	25.9	5.0	31.6	265.9
Cumulative effect of accounting change, net of tax benefit	—	—	(22.0)	(0.4)	(22.4)
Net income/(loss)	$ 203.4	$ 25.9	$ (17.0)	$ 31.2	$ 243.5
Total assets	$8,730.3	$890.0	$1,728.0	$(1,016.4)	$10,331.9
Total investments in plant	$ 380.6	$ 47.8	$ 15.4	$ 14.2	$ 458.0

(Millions of Dollars)	Regulated Utilities Electric	Gas	Competitive Energy Subsidiaries	Eliminations And Other	Total
For the Year Ended December 31, 2000					
Operating revenues	$4,738.5	$251.2	$1,894.9	$(1,008.0)	$ 5,876.6
Depreciation and amortization	(483.5)	(21.7)	(8.4)	(3.0)	(516.6)
Other operating expenses	(3,594.6)	(202.5)	(1,821.6)	953.5	(4,665.2)
Operating income/(loss)	660.4	27.0	64.9	(57.5)	694.8
Other (loss)/income, net	(11.6)	(7.1)	(4.7)	9.1	(14.3)
Interest expense, net	(191.9)	(12.2)	(53.4)	(41.8)	(299.3)
Income tax (expense)/benefit	(173.4)	(6.5)	(0.1)	18.3	(161.7)
Preferred dividends	(14.2)	—	—	—	(14.2)
Income/(loss) before extraordinary loss	269.3	1.2	6.7	(71.9)	205.3
Extraordinary loss, net of tax benefit	(214.2)	—	(19.7)	—	(233.9)
Net income/(loss)	$ 55.1	$ 1.2	$ (13.0)	$ (71.9)	$ (28.6)
Total assets	$9,620.0	$912.6	$ 684.1	$ (999.6)	$10,217.1
Total investments in plant	$ 373.5	$ 21.6	$ 7.1	$ 11.8	$ 414.0

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*
2002				
Operating Revenues	$1,284,461	$1,141,928	$1,414,304	$1,375,628
Operating Income	114,286	94,051	118,095	140,223
Net Income	18,642	28,857	48,575	56,035
Basic and Fully Diluted Earnings per Common Share	$ 0.14	$ 0.22	$ 0.38	$ 0.44
2001				
Operating Revenues	$ 1,708,436	$ 1,422,549	$ 1,544,375	$ 1,292,860
Operating Income	159,595	133,472	113,378	132,729
Income Before Cumulative Effect of Accounting Change	134,595	46,732	34,631	49,984
Cumulative Effect of Accounting Change, Net of Tax Benefit	(22,432)	—	—	—
Net Income	$ 112,163	$ 46,732	$ 34,631	$ 49,984
Basic and Fully Diluted Earnings Per Common Share:				
Income Before Cumulative Effect of Accounting Change	$ 0.93	$ 0.35	$ 0.26	$ 0.38
Cumulative Effect of Accounting Change, Net of Tax Benefit	(0.15)	—	—	—
Net Income	$ 0.78	$ 0.35	$ 0.26	$ 0.38

(a) Certain reclassifications of prior years' data have been made to conform with the current year's presentation. The summation of quarterly data may not equal annual data due to rounding. Operating revenue amounts have been reclassified from those reported in the first and second quarters related to the adoption of EITF Issue No. 02-3.

Selected Consolidated Financial Data (Unaudited)

(Thousands of Dollars, except percentages and share information)	*2002*	*2001*	*2000*	*1999*	*1998*
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 4,728,369	$ 4,472,977	$ 3,547,215	$ 3,947,434	$ 6,170,881
Total Assets	10,267,617	10,331,923	10,217,149	9,688,052	10,387,381
Total Capitalization (a)	4,670,771	4,576,858	4,739,417	5,216,456	6,030,402
Obligations Under Capital Leases (a)	16,803	17,539	159,879	181,293	209,279
Income Data:					
Operating Revenues	$ 5,216,321	$ 5,968,220	$ 5,876,620	$ 4,471,251	$ 3,767,714
Income/(Loss) Before Cumulative Effect of Accounting Change and Extraordinary Loss, Net of Tax Benefits	152,109	265,942	205,295	34,216	(146,753)
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	(22,432)	—	—	—
Extraordinary Loss, Net of Tax Benefit	—	—	(233,881)	—	—
Net Income/(Loss)	$ 152,109	$ 243,510	$ (28,586)	$ 34,216	$ (146,753)
Common Share Data:					
Basic Earnings/(Loss) Per Common Share:					
Income/(Loss) Before Cumulative Effect of Accounting Change and Extraordinary Loss, Net of Tax Benefits	$ 1.18	$ 1.97	$ 1.45	$ 0.26	$ (1.12)
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	(0.17)	—	—	—
Extraordinary Loss, Net of Tax Benefit	—	—	(1.65)	—	—
Net Income/(Loss)	$ 1.18	$ 1.80	$ (0.20)	$ 0.26	$ (1.12)
Fully Diluted Earnings/(Loss) Per Common Share:					
Income/(Loss) Before Cumulative Effect of Accounting Change and Extraordinary Loss, Net of Tax Benefits	$ 1.18	1.96	1.45	0.26	(1.12)
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	(0.17)	—	—	—
Extraordinary Loss, Net of Tax Benefit	—	—	(1.65)	—	—
Net Income/(Loss)	$ 1.18	$ 1.79	$ (0.20)	$ 0.26	$ (1.12)
Basic Common Shares Outstanding (Average)	129,150,549	135,632,126	141,549,860	131,415,126	130,549,760
Fully Diluted Common Shares Outstanding (Average)	129,341,360	135,917,423	141,967,216	132,031,573	130,549,760
Dividends Per Share	$ 0.53	$ 0.45	$ 0.40	$ 0.10	$ —
Market Price – Closing (high) (c)	$ 20.57	$ 23.75	$ 24.25	$ 22.00	$ 17.25
Market Price – Closing (low) (c)	$ 13.20	$ 16.80	$ 18.25	$ 13.56	$ 11.69
Market Price – Closing (end of year) (c)	$ 15.17	$ 17.63	$ 24.25	$ 20.56	$ 16.00
Book Value Per Share (end of year)	$ 17.33	$ 16.27	$ 15.43	$ 15.80	$ 15.63
Tangible Book Value Per Share (end of year)	$ 14.62	$ 13.71	$ 13.09	$ 15.53	$ 15.63
Rate of Return Earned on Average Common Equity (%)	7.0	11.2	(1.3)	1.6	(7.0)
Market-to-Book Ratio (end of year)	0.9	1.1	1.6	1.3	1.0
Capitalization:					
Common Shareholders' Equity	47%	46%	47%	40%	34%
Preferred Stock (a) (b)	3	3	4	5	5
Long-Term Debt (a)	50	51	49	55	61
	100%	100%	100%	100%	100%

(a) *Includes portions due within one year.*

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

(c) *Market price information reflects closing prices as presented in the* Wall Street Journal.

Consolidated Electric Sales Statistics (Unaudited)

	2002	2001	2000	1999	1998
Revenues: *(Thousands)*					
Residential	$1,512,397	$1,490,487	$1,469,439	$1,517,913	$1,475,363
Commercial	1,294,943	1,303,351	1,256,126	1,272,969	1,273,146
Industrial	485,592	549,808	566,625	560,801	568,913
Other Utilities	1,190,396	1,761,324	1,884,082	926,056	336,623
Streetlighting and Railroads	43,679	43,889	45,998	45,564	47,682
Nonfranchised Sales	—	(3,438)	16,932	24,659	22,479
Miscellaneous	41,357	67,809	96,666	52,357	16,429
Total Electric	4,568,364	5,213,230	5,335,868	4,400,319	3,740,635
Gas	466,596	566,814	461,716	—	—
Other	181,361	188,176	79,036	70,932	27,079
Total	$5,216,321	$5,968,220	$5,876,620	$4,471,251	$3,767,714
Sales: *(kWh – Millions)*					
Residential	13,923	13,322	12,940	12,912	12,162
Commercial	14,103	13,751	13,023	12,850	12,477
Industrial	6,265	6,790	7,130	7,050	6,948
Other Utilities	85,224	51,789	42,127	33,575	9,742
Streetlighting and Railroads	344	332	333	314	320
Nonfranchised Sales	—	—	107	147	193
Total	119,859	85,984	75,660	66,848	41,842
Customers: *(Average)*					
Residential	1,614,239	1,610,154	1,576,068	1,569,932	1,555,013
Commercial	183,577	171,218	166,114	164,932	162,500
Industrial	7,763	7,730	7,701	7,721	7,847
Other	3,949	3,969	3,917	3,908	3,890
Total Electric	1,809,528	1,793,071	1,753,800	1,746,493	1,729,250
Gas	190,855	190,998	185,328	—	—
Total	2,000,383	1,984,069	1,939,128	1,746,493	1,729,250
Average Annual Use Per Residential Customer *(kWh)*	8,611	8,251	8,233	8,243	7,799
Average Annual Bill Per Residential Customer	$ 934.90	$ 923.70	$ 934.94	$ 969.38	$ 946.80
Average Revenue Per kWh:					
Residential	10.86¢	11.20¢	11.36¢	11.76¢	12.14¢
Commercial	9.18	9.48	9.65	9.91	10.20
Industrial	7.75	8.10	7.95	7.95	8.19

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Attorney

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Charles W. Shivery
President-Competitive Group

Gregory B. Butler
Vice President, Secretary and General Counsel

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Vice President-Accounting and Controller

O. Kay Comendul
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PSNH – Public Service Company of New Hampshire

WMECO – Western Massachusetts Electric Company

Yankee – Yankee Gas Services Company

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Chairman, PSNH, WMECO and Yankee

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Chief Executive Officer, CL&P, PSNH, WMECO and Yankee

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O. Kay Comendul
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Patricia A. Wood
Clerk, WMECO

Competitive Company Officers

SESI – Select Energy Services, Inc.

NGC – Northeast Generation Company

NGS – Northeast Generation Services Company

NUEI – NU Enterprises, Inc.

Select – Select Energy, Inc.

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Chairman NGC, NGS and Select

William W. Schivley
Chairman of the Board, SESI
President, Select
Vice President, NUEI

James B. Redden
President, SESI

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Senior Vice President-Power Marketing, Select
Vice President, NUEI and NGC

Stephen J. Fabiani
Vice President-Retail Sales and Marketing, Select

Linda A. Jensen
Vice President-Finance, Treasurer and Clerk, SESI

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Vice President, NGC

John J. Roman
Vice President-Accounting and 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.

Shareholder Information

Shareholders

As of December 31, 2002, there were 65,176 common shareholders of record of Northeast Utilities holding an aggregate of 149,375,847 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 sales 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
2002	First	$19.87	$17.61	$0.125
	Second	$20.57	$18.05	$0.125
	Third	$18.45	$13.84	$0.1375
	Fourth	$16.97	$13.20	$0.1375
2001	First	$23.75	$16.80	$0.10
	Second	$20.75	$17.35	$0.10
	Third	$20.79	$18.30	$0.125
	Fourth	$19.25	$16.95	$0.125

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 13, 2003, at the Naismith Memorial Basketball Hall of Fame in Springfield, Massachusetts.

Form 10-K

Northeast Utilities will provide shareholders a copy of its 2002 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 01641-0270

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 1,809,528 million electric customers in Connecticut, New Hampshire and Massachusetts and 190,855 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 services)*

Select Energy Services, Inc. *(energy management)*

Support Subsidiary

Northeast Utilities Service Company *(system-wide 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

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