Annual Report 1998

New England Power Company

A Subsidiary of
New England Electric System

New England Power
A NEES company

New England Power Company
25 Research Drive
Westborough, Massachusetts 01582

Directors
(As of January 1, 1999)

Peter G. Flynn
President of the Company

Alfred D. Houston
Chairman of the Company and Chairman of New England Electric System

Cheryl A. LaFleur
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of New England Electric System

Richard P. Sergel
President and Chief Executive Officer of New England Electric System

Officers
(As of January 1, 1999)

Alfred D. Houston
Chairman of the Company and Chairman of New England Electric System

Peter G. Flynn
President of the Company

Michael E. Jesanis
Vice President of the Company and Senior Vice President and Chief Financial Officer of New England Electric System

Cheryl A. LaFleur
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of New England Electric System

John F. Malley
Vice President of the Company

Masheed H. Rosenqvist
Vice President of the Company and of certain affiliates

James S. Robinson
Vice President of the Company

Robert King Wulff
Clerk of the Company and of certain affiliates, Secretary or Assistant Clerk of certain affiliates and Assistant Secretary of an affiliate

John G. Cochrane
Treasurer of the Company and of certain affiliates, Vice President of an affiliate, Assistant Treasurer of an affiliate and Treasurer of New England Electric System

Kirk L. Ramsauer
Assistant Clerk of the Company and of certain affiliates, and Secretary, Assistant Secretary or Clerk of certain affiliates

Howard W. McDowell
Assistant Treasurer and Controller of the Company and of certain affiliates, Senior Vice President of an affiliate, Treasurer or Controller of certain affiliates and Assistant Secretary of an affiliate

Transfer Agent, Dividend Paying Agent, and Registrar of Preferred Stock
BankBoston, N.A., Boston, Massachusetts

New England Power Company

New England Power Company, (the Company) a wholly owned subsidiary of New England Electric System (NEES), is a Massachusetts corporation qualified to do business in Massachusetts, New Hampshire, Rhode Island, Connecticut, Maine, and Vermont. The Company is subject, for certain purposes, to the jurisdiction of the regulatory commissions of these six states, the Securities and Exchange Commission, under the Public Utility Holding Company Act of 1935, the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission. The Company's business is primarily the transmission of electric energy in wholesale quantities to other electric utilities, principally its distribution affiliates Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company, and The Narragansett Electric Company (Narragansett Electric). In September 1998, the Company and Narragansett Electric completed the divestiture of substantially all of their nonnuclear generating business. However, the Company continues to own minority interests in two joint owned nuclear generating units as well as minority equity interests in 4 nuclear generating companies. For further information on industry restructuring and the divestiture of NEES' nonnuclear generating business, refer to the "Industry Restructuring" section of Financial Review.

In December 1998, NEES agreed to a merger with The National Grid Group plc, whose principal subsidiary operates the transmission system in England and Wales.

In February 1999, NEES entered into an agreement to acquire Eastern Utilities Associates, a utility holding company serving approximately 300,000 customers in Massachusetts and Rhode Island. For further information on these proposed mergers, refer to the "Merger Agreements" sections of Financial Review.

Report of Independent Accountants

New England Power Company, Westborough, Massachusetts:

In our opinion, the accompanying balance sheets and the related statements of income, of retained earnings, and of cash flows present fairly, in all material respects, the financial position of New England Power Company (the Company), a wholly owned subsidiary of New England Electric System, at December 31, 1998 and 1997, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles. 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 of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

Boston, Massachusetts
February 23, 1999

PricewaterhouseCoopers LLP

New England Power Company
Financial Review

Merger Agreement with The National Grid Group plc

On December 11, 1998, New England Electric System (NEES), The National Grid Group plc (National Grid), and NGG Holdings LLC (Holdings), a directly and indirectly wholly owned subsidiary of National Grid, entered into an Agreement and Plan of Merger (Merger Agreement). Pursuant to the Merger Agreement, Holdings will merge with and into NEES (the Merger), with NEES becoming a wholly owned subsidiary of National Grid. New England Power Company (the Company) will remain a wholly owned subsidiary of NEES.

The Merger is subject to approval by a majority vote of NEES shareholders as well as National Grid shareholder approval. In addition, the Merger is subject to a number of regulatory and other approvals and consents, including approvals by the Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935 (1935 Act), Federal Energy Regulatory Commission (FERC), and Nuclear Regulatory Commission (NRC), support or approval from the states in which NEES subsidiaries operate, and clearance under both the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the Exon-Florio Provisions of the Omnibus Trade and Competitiveness Act of 1988. National Grid has obtained governmental clearance in the United Kingdom for the Merger. The Merger is expected to be completed by early 2000.

Merger Agreement with Eastern Utilities Associates

On February 1, 1999, NEES, Eastern Utilities Associates (EUA), and Research Drive LLC (Research Drive), a directly and indirectly wholly owned subsidiary of NEES, entered into an Agreement and Plan of Merger (EUA Agreement). Pursuant to the EUA Agreement, Research Drive will merge with and into EUA, with EUA becoming a wholly owned subsidiary of NEES.

The acquisition of EUA is subject to approval by a two-thirds vote of EUA shareholders. In addition, the acquisition is subject to a number of regulatory and other approvals and consents, including approvals by the SEC, under the 1935 Act, FERC, and NRC, support or approval from the states in which EUA subsidiaries operate, and clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. The EUA acquisition is expected to be completed by early 2000. Following the acquisition of EUA, the subsidiaries of NEES and EUA whose operations are similar are expected to be consolidated.

Industry Restructuring

During 1998, pursuant to legislation enacted in Massachusetts, Rhode Island, and New Hampshire, and settlement agreements approved by state and federal regulators (the Settlement Agreements), all customers were provided the right to purchase electricity from the power supplier of their choice. The NEES companies remain obligated to deliver that electricity over its transmission and distribution systems, with such delivery services provided under regulated rates approved by state and federal regulators. As described below, those delivery rates include a non-bypassable charge for the costs of NEES' former generating business which were not recovered through the sale of that business ("stranded costs"), which was substantially completed in 1998. As a result of the Settlement Agreements, customers' choice of power supplier has no impact on NEES' transmission and distribution business or on its ability to recover stranded costs. In order to facilitate the implementation of customer choice, the Settlement Agreements provided for the termination of the Company's requirements contracts with its affiliated distribution customers. The Company's requirements contracts with unaffiliated customers have also generally been terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service to new customer load in Rhode Island.

On September 1, 1998, the Company and The Narragansett Electric Company (Narragansett Electric) (collectively, the Sellers) completed the sale of substantially all of their nonnuclear generating business, all of which had a book value of approximately $1.1 billion, to USGen New England, Inc. (USGen), an indirect wholly owned subsidiary of PG&E Corporation. The Sellers received $1.59 billion for the sale. In addition, the Company was reimbursed approximately $140 million for costs associated with early retirements and special severance programs for employees affected by industry restructuring, and the value of inventories. USGen assumed responsibility for environmental conditions at the Sellers' nonnuclear generating stations. USGen also assumed the Sellers' obligations under long-term fuel and fuel transportation contracts, and certain collective bargaining agreements.

As part of the sale, the Company also signed a purchased power transfer agreement through which USGen purchased the Company's entitlement to approximately 1,100 megawatts (MW) of power procured under long-term contracts in exchange for monthly fixed payments by the Company averaging $9.5 million per month through January 2008 (having a net present value of $833 million) toward the above-market cost of those contracts. In some cases, these transfers involved formal assignment of the contracts to USGen and a release of the Company from further obligations to the power supplier, while others did not. For those that involved formal assignment, the Company was required to make a lump sum payment equivalent to the present value of the monthly fixed payment obligations of those contracts. On or prior to the closing date, the Company made lump sum payments totaling approximately $340 million and was released from further obligations relating to two of the contracts. These lump sum payments are separate from the $833 million figure referred to above.

As part of the divestiture plan, in February 1998, New England Energy Incorporated (NEEI), a wholly owned subsidiary of NEES, whose costs had been supported by the Company, sold its oil and gas properties for approximately $50 million. NEEI's loss on the sale of approximately $120 million, before tax, has been reimbursed by the Company.

In addition, the Company agreed under the Settlement Agreements to endeavor to sell its minority interest in three nuclear power plants and a 60 MW interest in a fossil-fueled generating station in Maine. In February 1999, Vermont Yankee Nuclear Power Corporation entered into a letter of intent to sell its assets. For further information, refer to the "Nuclear Units" section of this Financial Review.

The Settlement Agreements provide that the Company's stranded costs are to be recovered from its wholesale customers through contract termination charges (CTC). The affiliated wholesale customers, in turn, are recovering those costs through their delivery charges to distribution customers. Under the Settlement Agreements, the recovery of the Company's stranded costs is divided into several categories. Unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets will be fully recovered through the CTC by the end of 2000 and earn a return on equity averaging 9.7 percent. The Company's obligation relating to the above-market cost of purchased power contracts and nuclear decommissioning costs are recovered through the CTC over a longer period of time, as such costs are actually incurred. The CTC rate was originally set at 2.8 cents per kilowatthour (kWh), and subsequently reduced to approximately 1.5 cents or less per kWh upon completion of the sale of the Company's nonnuclear generating business. As the CTC rate declines, the Company, under certain of the Settlement Agreements, earns incentives based on successful mitigation of its stranded costs. These incentives supplement the Company's return on equity. Finally, the Settlement Agreements provide that until such time as the Company divests its operating nuclear interests, the Company will share with customers, through the CTC, 80 percent of the revenues and operating costs related to the units, with shareholders retaining the balance.

Accounting Implications

Historically, electric utility rates have been based on a utility's costs. As a result, electric utilities are subject to certain accounting standards that are not applicable to other business enterprises in general. Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71), requires regulated entities, in appropriate circumstances, to establish regulatory assets, and thereby defer the income statement impact of these charges because they are expected to be included in future customer charges. In 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) concluded that a utility that had received approval to recover stranded costs through regulated transmission and distribution rates would be permitted to continue to apply FAS 71 to the recovery of stranded costs.

The Company has received authorization from the FERC to recover through the CTC substantially all of the costs associated with its former generating business not recovered through the sale of that business. Additionally, FERC Order No. 888 enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of the Company's business, including the recovery of its stranded costs, remains under cost-based rate regulation. The Company believes these factors and the EITF conclusion allow it to continue to apply FAS 71. Because of the nuclear cost-sharing provisions related to the Company's CTC, the Company ceased applying FAS 71 in 1997 to 20 percent of its ongoing nuclear operations, the impact of which is immaterial.

Currently, there is much regulatory and other movement toward establishing performance-based rates. It is possible that the adoption of performance-based rates for the Company or its affiliates, future regulatory rules, or other circumstances could cause the application of FAS 71 to be discontinued. This discontinuation would result in a noncash write-off of previously established regulatory assets, including those being recovered through the Company's CTC.

As a result of applying FAS 71, the Company has recorded a regulatory asset for the costs that are recoverable from customers through the CTC. The regulatory asset reflects the loss on the sale of NEES' oil and gas business and the unrecovered plant costs in operating nuclear plants (assuming no market value), the costs associated with permanently closed nuclear power plants, and the present value of the payments associated with the above-market costs of purchased power contracts, reduced by the gain from the sale of the nonnuclear generating business. At December 31, 1998, the regulatory asset related to the CTC was approximately $1.5 billion, of which $1.2 billion related to the above-market costs of purchased power contracts.

As described above, the CTC regulatory asset includes the unrecovered plant costs associated with the Company's interest in operating nuclear plants. This balance sheet treatment is due to the Company's conclusion that its interests in the Millstone 3 and Seabrook 1 nuclear generating units have little, if any, market value. Three proposed sales of nuclear units by other utilities have required the seller to set aside amounts for decommissioning in excess of the proceeds from the sale of the units. Two of these proposed sales were agreed upon prior to the end of the third quarter of 1998. As a result, at the end of the third quarter of 1998, the Company recorded an impairment writedown in its reserve for depreciation of approximately $390 million, which represents the net book value at December 31, 1995, less applicable depreciation subsequent to that date, of Millstone 3 and Seabrook 1. Because the Settlement Agreements permit the Company to recover its pre-1996 investment as well as decommissioning expenses through the CTC, the Company established a regulatory asset in an amount equal to the impairment writedown. Should the Company's efforts to sell its nuclear interests result in a gain over the amounts remaining in the plant account, such gain will be credited to customers through the CTC.

Overview of Financial Results

Net income for 1998 decreased $22 million compared with 1997 primarily due to the sale of the Company's nonnuclear generating business on September 1, 1998. The decrease is also attributable to reduced revenues as a result of the termination of its all-requirements contracts with its primary customers. For further information on the termination of these contracts, see the "Operating Revenue" section.

Net income for 1997 decreased $8 million compared with 1996. The decrease was primarily due to increased operation and maintenance costs, partially offset by a transmission rate increase, decreased purchased electric energy costs, excluding fuel, and decreased depreciation and amortization.

Operating Revenue

Operating revenue for 1998 decreased $460 million compared with 1997.

Under the provisions of all-requirements contracts, the Company historically furnished all electrical requirements to its affiliated wholesale customers, obligating the Company to supply such requirements at its standard resale rates. As a result of the Settlement Agreements, the all-requirements provisions of the contracts with the Company's primary customers in Rhode Island, Massachusetts, and New Hampshire were terminated effective January 1, 1998, March 1, 1998, and July 1, 1998, respectively. As of those dates, the Company continued to supply power to the affiliates to meet their standard offer generation service obligations, but at lower rates. On September 1, 1998, the Company sold its nonnuclear generating business, and USGen and TransCanada Power Marketing, Ltd. became the principal wholesale suppliers for the affiliated companies.

Partially offsetting this revenue decrease is billings of CTCs and an increase in transmission billings.

Operating revenue for 1997 increased $78 million compared with 1996 primarily due to increased fuel recovery, the effect of a transmission rate increase that went into effect in mid-1996, and stranded investment recovery related to amounts recovered in connection with retail wheeling pilot programs and the first phase of customer choice in Rhode Island. These increases were offset by decreased sales due to a decrease in peak demand billing as a result of milder weather in the first quarter of 1997 and reduced load due to retail wheeling pilot programs. For a discussion of fuel recovery revenues, see the discussion of the 1997 increase in fuel costs in the "Operating Expenses" section.

Operating Expenses

Operating expenses for 1998 decreased $426 million compared with 1997. The September 1, 1998 sale of the Company's nonnuclear generating business had the impact of decreasing all categories of operating expenses. The decrease in operating expenses also reflects reduced charges of $22 million from the Maine Yankee nuclear power plant, which was closed in mid-1997 and reduced charges of $3 million and $12 million from the partially owned Seabrook 1 and Millstone 3 nuclear generating facilities, respectively. Operating expenses were also lower due to lower charges related to postretirement benefits other than pensions (PBOPs), reflecting the completion of the accelerated amortization of NEP's deferred PBOP costs in 1997 under the terms of a 1995 rate agreement.

The decrease in depreciation and amortization expense related to the sale of the nonnuclear generating business was more than offset by CTC amortization and the accelerated amortization of Millstone 3, a portion of which was attributable to the completion of the PBOP amortization discussed above.

Operating expenses for 1997 increased $91 million compared with 1996 primarily due to increased fuel costs, increased charges from the Maine Yankee nuclear power plant, and increased other operation and maintenance expenses.

Fuel costs represented fuel for generation and the portion of purchased electric energy permitted in the past to be recovered through the Company's fuel adjustment clause. The increase in fuel costs reflected increased power supply to other utilities, increased replacement power costs due to the reduced generation from partially owned nuclear units, and an increase in the cost of short-term purchased power.

The increase in other operation and maintenance expenses in 1997 was due to an increase in transmission wheeling costs, increased maintenance costs at the partially owned Seabrook 1 and Millstone 3 nuclear facilities, an increase in deferred PBOP amortization, an overall increase in general and administrative costs, start-up costs associated with the new regional transmission control organization, and the Company's share of costs associated with the restoration to service of previously idled facilities throughout New England in response to a tightening regional power supply.

The increase in operating expenses in 1997 was partially offset by a decrease in purchased power charges from the Connecticut Yankee nuclear power plant, which was permanently closed in December 1996. This decrease was partially offset by increased charges from the Maine Yankee nuclear power plant, which was permanently closed in mid-1997.

Nuclear Units

Nuclear Units Permanently Shut Down

Three regional nuclear generating companies in which the Company has a minority interest own nuclear generating units that have been permanently shut down. These three units are as follows:

Unit	NEP's Investment %	NEP's Investment $ (millions)	Date Retired	Future Estimated Billings to NEP $ (millions)
Yankee Atomic	30	6	Feb 1992	24
Connecticut Yankee	15	16	Dec 1996	75
Maine Yankee	20	16	Aug 1997	143

In the case of each of these units, the Company has recorded a liability and an offsetting regulatory asset reflecting the estimated future billings from the companies. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant as well as unfunded nuclear decommissioning costs and other costs. Connecticut Yankee and Maine Yankee have both filed similar requests with the FERC. Several parties have intervened in opposition to both filings. In August 1998, a FERC Administrative Law Judge (ALJ) issued an initial decision which would allow for full recovery of Connecticut Yankee's unrecovered investment, but precluded a return on that investment. Connecticut Yankee, the Company, and other parties have filed with the FERC exceptions to the ALJ's decision. Should the FERC uphold the ALJ's initial decision in its current form, the Company's share of the loss of the return component would total approximately $12 million to $15 million before taxes. In January 1999, parties in the Maine Yankee proceeding filed a comprehensive settlement agreement with the FERC, under which Maine Yankee would recover all unamortized investment in the plant, including a return on its equity investment of 6.5 percent, as well as decommissioning costs and other costs. This settlement agreement requires FERC approval. The Company's industry restructuring settlements allow it to recover all costs that the FERC allows these Yankee companies to bill to the Company.

The Company and several other shareholders (Sponsors) of Maine Yankee are parties to 27 contracts (Secondary Purchase Agreements) under which they sold portions of their entitlements to Maine Yankee power output through 2002 to various entities, primarily municipal and cooperative systems in New England (Secondary Purchasers). Virtually all of the Secondary Purchasers had ceased making payments under the Secondary Purchase Agreements, claiming that such agreements excuse further payments upon plant shutdown. In February 1999, a settlement agreement which fully resolves the dispute between the Sponsors and Secondary Purchasers was filed with the FERC, under which the Secondary Purchasers would be required to make certain payments to Maine Yankee, and, in turn, to the Company, related to both past and future obligations under the Secondary Purchase Agreements. This settlement agreement requires FERC approval. Shutdown costs are recoverable from customers under the Settlement Agreements.

A Maine statute provides that if both Maine Yankee and its decommissioning trust fund have insufficient assets to pay for the plant decommissioning, the owners of Maine Yankee are jointly and severally liable for the shortfall.

Operating Nuclear Units

The Company has minority interests in three other nuclear generating units: Vermont Yankee, Millstone 3, and Seabrook 1. Uncertainties regarding the future of nuclear generating stations, particularly older units, such as Vermont Yankee, are increasing rapidly and could adversely affect their service lives, availability, and costs. These uncertainties stem from a combination of factors, including the acceleration of competitive pressures in the power generation industry and increased NRC scrutiny. The Company performs periodic economic viability reviews of operating nuclear units in which it holds ownership interests.

Vermont Yankee

On February 25, 1999, the Board of Directors of Vermont Yankee Nuclear Power Corporation granted an exclusive right to AmerGen Energy Company (AmerGen), a joint venture by PECO Energy and British Energy to conduct a due diligence review over the next 120 days and negotiate a possible agreement to purchase the assets of Vermont Yankee, Vermont's sole nuclear generating plant. Provided the due diligence review leads to successful completion of negotiations for a sale, consummation of such a sale would be contingent on regulatory approvals by the NRC, the SEC, under the 1935 Act, and the Vermont Public Service Board, among others. The sale process could take eight to twelve months or longer. In past negotiations for the sale of nuclear plants, due diligence review has not guaranteed that a sale will occur. The Company has a 20 percent ownership interest in Vermont Yankee and an investment of approximately $11 million at December 31, 1998.

Millstone 3

In July 1998, Millstone 3 returned to full operation after being shut down since April 1996. Millstone 3 remains on the NRC "Watch List," signifying that it continues to warrant increased NRC attention. Millstone 3 is operated by a subsidiary of Northeast Utilities (NU). The Company is not an owner of the Millstone 2 nuclear generating unit, which is temporarily shut down under NRC orders, or the Millstone 1 nuclear generating unit, which has been permanently shut down. A criminal investigation related to Millstone 3 is ongoing.

In August 1997, the Company sued NU in Massachusetts Superior Court for damages resulting from the tortious conduct of NU that caused the shutdown of Millstone 3. The Company's damages include the costs of replacement power during the outage, costs necessary to return Millstone 3 to safe operation, and other additional costs. Most of the Company's incremental replacement power costs have been recovered from customers, either through fuel adjustment clauses or through provisions in the Settlement Agreements. The Company also seeks punitive damages. The Company also sent a demand for arbitration to Connecticut Light & Power Company and Western Massachusetts Electric Company, both subsidiaries of NU, seeking damages resulting from their breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3. The arbitration is scheduled for October 1999. In July 1998, the court denied NU's motion to dismiss and its motion to stay pending arbitration. The Company subsequently amended its complaint by, among other things, adding NU's Trustees as defendants. In December 1998, NU moved for summary judgement. The Company's suit has been consolidated with suits filed by other joint owners. The court is in the process of scheduling a trial date. Some or all of the damages awarded from the lawsuit would be refunded to customers.

Year 2000 Readiness Disclosure

Over the next year, most companies will face a potentially serious information systems (computer) problem because many software applications and operational programs written in the past may not properly recognize calendar dates associated with the year 2000 (Y2K). This could cause computers to either shut down or lead to incorrect calculations.

During 1996, the NEES companies began the process of identifying the changes required to their computer software and hardware to mitigate Y2K issues. The NEES companies established a Y2K Project team to manage these issues, which has consisted of as many as 70 full-time equivalent staff at some points in time, primarily external consultants being overseen by an internal Y2K management team. To facilitate the Y2K Project, NEES entered into contracts with Keane, Inc. and International Business Machines Corporation to provide personnel support to the Y2K Project. Through December 31, 1998, the NEES companies have spent approximately $14 million with these vendors, which is included in the cost figures disclosed below. The Y2K Project team reports project progress to a Y2K Executive Oversight Committee each month. The team also makes regular reports to NEES' Board of Directors and its Audit Committee. The NEES companies have separated their Y2K Project into four parts as shown below, along with the estimated completion dates for each part.

Category	Specific Example	Substantial Completion of Critical Systems	Contingency Testing, Documentation, and Clean Management
Mainframe/Midrange systems	Accounting/Customer service integrated systems	Completed	Throughout 1999
Desktop systems	Personal computers/ Department software/ Networks	June 30, 1999	Throughout 1999
Operational/ Embedded systems	Dispatching systems/ Transmission and Distribution systems/ Telephone systems	June 30, 1999	Throughout 1999
External issues	Electronic Data Interchange/Vendor communications	June 30, 1999	Throughout 1999

The NEES companies are using a three-phase approach in coordinating their Y2K Project for system-related issues: (I) Assessment and Inventory, (II) Pilot Testing, and (III) Renovation, Conversion, or Replacement of Application and Operating Software Packages and Testing. Phase I, which was an initial assessment of all systems and devices for potential Y2K defects, was completed in mid-1997. These assessments included, but were not limited to, the review of program code for mainframe and midrange systems, analysis of personal computer hardware and network equipment for desktop systems, reaching consensus with key "data exchange" partners regarding the approach and execution of plans to address Y2K-related issues, and coordination with other New England Power Pool (NEPOOL) member utilities related to operational systems, such as transmission systems. Phase II, which consisted of renovation pilots for a cross-section of systems in order to facilitate the establishment of templates for Phase III work, was completed in late 1997. Phase III, which is currently ongoing, requires the renovation, conversion, or replacement of the remaining applications and operating software packages.

Critical systems include major operational and informational systems such as the NEES companies' financial-related and customer information systems. These mission critical systems were first addressed at an individual component level, and then, upon satisfactory completion of that testing, reviewed at an integrated level, during which the Y2K Project team tested for Y2K problems which could be caused by various system interfaces. Additionally, contingency plans are being formulated for mission critical systems, as described below.

The overall Y2K Project has also been designed such that Y2K-related work performed by external consultants is reviewed by NEES employees, and vice-versa. The Y2K Project team management periodically benchmarks its progress against the recommended progress schedule documented by the North American Electric Reliability Council (NERC), and is currently ahead of the recommended schedule.

The NEES companies have also implemented a formalized communication process with third parties to give and receive information related to their progress in remediating their own Y2K issues, and to communicate the NEES companies' progress in addressing the Y2K issue. These third parties include major customers, suppliers, and significant businesses with which the NEES companies have data links (such as banks). The NEES companies have identified standard offer generation service providers, telecommunications companies, and the Independent System Operator-New England (ISO New England) as critical to business operations. The NEES companies have been in contact with all of these parties regarding the progress of their Y2K remediation efforts, and will continue to monitor their ongoing remediation efforts through continued communications. The NEES companies cannot predict the outcome of other companies' remediation efforts. Therefore, contingency plans are being developed, as described below.

The NEES companies believe total costs associated with making the necessary modifications to all centralized and noncentralized systems will be approximately $28 million. These costs include the replacement of approximately one thousand desktop computers. In addition, the NEES companies are spending $4 million related to the replacement of the human resources and payroll system, in part due to the Y2K issue. To date, total Y2K-related costs of $25 million have been incurred, of which $3 million has been capitalized. The NEES companies continually review their cost estimates based upon the overall Y2K Project status, and update these estimates as warranted.

The NEES companies are in the process of developing Y2K contingency plans to allow for critical information and operating systems to function from January 1, 2000 forward. If required, these plans are intended to address both internal risks as well as potential external risks related to suppliers and customers. Part of the contingency planning for accounting and desktop systems will include taking extensive data back-ups prior to year-end closing. For operational systems, the NEES companies have in place an overall disaster recovery program, which already includes periodic disaster simulation training (for outages due to severe weather, for instance). As part of Y2K contingency planning, the NEES companies will review their disaster recovery plans, modifying them for Y2K-specific issues, such as a potential loss of telecommunication services. The NEES companies expect that these contingency plans will be in place by the third quarter of 1999.

Interregional and regional contingency plans are being formulated that address emergency scenarios due to the interconnection of utility systems throughout the United States. At a regional level, the NEES companies are participating and cooperating with NEPOOL and ISO New England. Overall regional activities, including those of NEPOOL and ISO New England, will be coordinated by the Northeast Power Coordinating Council, whose activities will be incorporated into the interregional coordinating effort by NERC. The target for the completion of this planning process is mid-1999. The NEES companies have noted that the Y2K coordination efforts by ISO New England began in May 1998, resulting in a demanding and difficult schedule to attain regional and interregional target dates.

The NEES companies believe the worst case scenario with a reasonable chance of occurring is temporary disruptions of electric service. This scenario could result from a failure to adequately remediate Y2K problems at NEES company facilities or could be caused by the inability of entities, such as ISO New England, to maintain the short-term reliability of various generators and/or transmission lines on a regional or interregional basis. The NEES companies believe that the contingency plans being developed both internally and on a regional level, as described above, should substantially mitigate the risks of this potential scenario. In the event that a short-term disruption in service occurs, NEES does not expect that it would have a material impact on its financial position and results of operations.

While the NEES companies believe that their overall Y2K program will satisfactorily address all critical operational and system-related issues, significant risks remain. These risks include, but are not limited to, the Y2K readiness of third parties, including other utilities and power suppliers, cost and timeline estimates of remaining Y2K mitigation efforts, and the overall accuracy of assumptions made related to future events in the development of the Y2K mitigation effort.

New Accounting Standards

In 1997, the FASB released Statement of Financial Accounting Standards No. 130, Reporting of Comprehensive Income (FAS 130), which was adopted by the Company in the first quarter of 1998. FAS 130 establishes standards for reporting comprehensive income and its components. Comprehensive income for the period is equal to net income plus "other comprehensive income," which for the Company, consists of the change in unrealized holding gains on available-for-sale securities during the period. Other comprehensive income was immaterial for the Company for the year ended December 31, 1998.

Also in 1997, the FASB released Statement of Financial Accounting Standards No. 131, Disclosure about Segments of an Enterprise and Related Information (FAS 131), which went into effect in 1998. FAS 131 requires the reporting in financial statements of certain new additional information about operating segments of a business. FAS 131 does not currently impact the Company's reporting requirements.

In February 1998, the FASB issued Statement of Financial Accounting Standards No. 132, Employers' Disclosures about Pensions and Other Postretirement Benefits (FAS 132), which revises disclosure requirements for pension and other postretirement benefits. The Company has adopted FAS 132 in its financial statements for the year ended December 31, 1998.

The adoption of FAS 130, FAS 131, and FAS 132 had no impact on the Company's operating results, financial position, or cash flows.

In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), which establishes accounting and reporting standards for such instruments. FAS 133 is effective for fiscal years beginning after June 15, 1999. Currently, the Company has no such derivative holdings.

Risk Management

The Company's major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable rate debt. At December 31, 1998, the Company's variable rate debt had a fair value of $372 million, a weighted average interest rate of 3.28 percent, and maturity dates of greater than five years.

See the "Industry Restructuring" section above for a discussion of the Company's purchased power transfer agreement with USGen. The Company retained one purchased power contract, with Vermont Yankee, which carries fixed payment requirements of approximately $35 million in 1999, $30 million in 2000, $35 million in 2001 and 2002, $30 million in 2003, and approximately $300 million thereafter.

Utility Plant Expenditures and Financing

Cash expenditures for utility plant totaled $64 million in 1998. These expenditures were primarily transmission-related. The funds necessary for utility plant expenditures during 1998 were primarily provided by internally generated funds and the proceeds from the sale of the nonnuclear generating business. Cash expenditures for 1999 are estimated to be $65 million, principally related to transmission functions. Internally generated funds are expected to fully cover the Company's capital expenditures in 1999.

In 1998, the Company defeased or retired all of its mortgage bonds. The Company also paid down all of its short-term debt outstanding.

In 1998, the Company repurchased or redeemed preferred stock with an aggregate par value of $38 million.

In 1998, the Company repurchased 2.7 million shares of its common stock from NEES for $418 million. Approximately $194 million in connection with the repurchase was charged to retained earnings.

At December 31, 1998, the Company had lines of credit and standby bond purchase facilities with banks totaling $455 million. These lines and facilities were available at December 31, 1998 for liquidity support for $372 million of the Company's bonds in tax-exempt commercial paper mode and for other corporate purposes. There were no borrowings under these lines of credit at December 31, 1998.

New England Power Company

Statements of Income

Year ended December 31 (In thousands)	1998	1997	1996
Operating revenue, principally from affiliates	**$1,218,340**	$1,677,903	$1,600,309
Operating expenses:			
Fuel for generation	**223,828**	372,734	342,545
Purchased electric energy	**399,836**	527,647	508,910
Other operation	**155,065**	241,506	203,456
Maintenance	**60,239**	89,820	79,118
Depreciation and amortization	**99,924**	98,024	104,209
Taxes, other than income taxes	**48,492**	67,311	66,416
Income taxes	**73,594**	90,009	91,894
Total operating expenses	**1,060,978**	1,487,051	1,396,548
Operating income	**157,362**	190,852	203,761
Other income:			
Allowance for equity funds used during construction	**633**	-	-
Equity in income of nuclear power companies	**5,284**	5,189	5,159
Other income (expense), net	**118**	(3,404)	(1,851)
Operating and other income	**163,397**	192,637	207,069
Interest:			
Interest on long-term debt	**30,775**	42,277	45,111
Other interest	**10,688**	7,055	10,066
Allowance for borrowed funds used during construction - credit	**(961)**	(1,238)	(591)
Total interest	**40,502**	48,094	54,586
Net income	**$ 122,895**	$ 144,543	$ 152,483

Statements of Retained Earnings

Year ended December 31 (In thousands)	1998	1997	1996
Retained earnings at beginning of year	**$ 407,630**	$ 400,610	$ 385,309
Net income	**122,895**	144,543	152,483
Dividends declared on cumulative preferred stock	**(1,230)**	(2,075)	(2,574)
Dividends declared on common stock, $20.25, $21.00, and $20.80 per share, respectively	**(130,610)**	(135,448)	(134,158)
Premium on redemption of preferred stock	**(264)**	-	(450)
Repurchase of common stock	**(193,818)**	-	-
Retained earnings at end of year	**$ 204,603**	$ 407,630	$ 400,610

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

New England Power Company

Balance Sheets

At December 31 (In thousands)	1998	1997
Assets		
Utility plant, at original cost	**$ 1,262,461**	$ 3,057,749
Less accumulated provisions for depreciation and amortization	**837,637**	1,196,972
	424,824	1,860,777
Construction work in progress	**33,289**	29,015
Net utility plant	**458,113**	1,889,792
Investments:		
Nuclear power companies, at equity (Note E-1)	**48,538**	49,825
Nonutility property and other investments	**39,583**	34,723
Total investments	**88,121**	84,548
Current assets:		
Cash and temporary cash investments (including $109,911 and $-0- with affiliates)	**179,413**	1,643
Accounts receivable:		
Affiliated companies	**107,878**	233,308
Accrued NEEI revenues	**-**	11,419
Others	**32,573**	26,638
Fuel, materials, and supplies, at average cost	**9,220**	47,492
Prepaid and other current assets	**21,569**	17,837
Total current assets	**350,653**	338,337
Regulatory assets (Note B)	**1,512,562**	441,038
Deferred charges and other assets	**5,339**	9,377
	$ 2,414,788	$ 2,763,092
Capitalization and Liabilities		
Capitalization:		
Common stock, par value $20 per share,		
Authorized - 6,449,896 shares		
Outstanding - 3,749,896 and 6,449,896 shares	**$ 74,998**	$ 128,998
Premium on capital stock	**50,371**	86,779
Other paid-in capital	**190,852**	289,818
Retained earnings	**204,603**	407,630
Unrealized gain on securities, net	**72**	34
Total common equity	**520,896**	913,259
Cumulative preferred stock, par value $100 per share (Note I)	**1,567**	39,666
Long-term debt	**371,765**	647,720
Total capitalization	**894,228**	1,600,645
Current liabilities:		
Long-term debt due in one year	**-**	50,000
Short-term debt (including $-0- and $3,125 to affiliates)	**-**	111,250
Accounts payable (including $119,657 and $14,373 to affiliates)	**162,360**	109,121
Accrued liabilities:		
Taxes	**15,009**	39
Interest	**2,440**	8,905
Other accrued expenses (Note H)	**20,086**	23,554
Dividends payable	**24**	35,474
Total current liabilities	**199,919**	338,343
Deferred federal and state income taxes	**165,115**	369,757
Unamortized investment tax credits	**30,870**	53,463
Accrued Yankee nuclear plant costs (Note E-2)	**242,138**	299,564
Purchased power obligations	**832,668**	-
Other reserves and deferred credits	**49,850**	101,320
Commitments and contingencies (Note E)		
	$ 2,414,788	$ 2,763,092

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

New England Power Company

Statements of Cash Flows

Year ended December 31 (In thousands)	1998	1997	1996
Operating activities:			
Net income	$ 122,895	$ 144,543	$ 152,483
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	104,331	101,186	108,338
Deferred income taxes and investment tax credits, net	(226,722)	(12,728)	(7,458)
Allowance for funds used during construction	(1,594)	(1,238)	(591)
Reimbursement to New England Energy Incorporated of loss on sale of oil and gas properties	(120,900)	-	-
Buyout of purchased power contracts	(326,590)	-	-
Decrease (increase) in accounts receivable	130,914	(25,128)	19,629
Decrease (increase) in fuel, materials, and supplies	(10,270)	11,217	(4,045)
Decrease (increase) in prepaid and other current asset	(8,778)	7,213	2,936
Increase (decrease) in accounts payable	(31,761)	(18,105)	(36,565)
Increase (decrease) in other current liabilities	5,037	(1,905)	9,640
Other, net	(49,611)	19,919	28,582
Net cash provided by (used in) operating activities	$ (413,049)	$ 224,974	$ 272,949
Investing activities:			
Proceeds from sale of generating assets	$ 1,688,863	$ -	$ -
Plant expenditures, excluding allowance for funds used during construction	(64,446)	(69,863)	(65,981)
Other investing activities	(5,474)	(4,040)	(3,878)
Net cash provided by (used in) investing activities	$ 1,618,943	$ (73,903)	$ (69,859)
Financing activities:			
Capital contribution from parent	$ 34,881	$ -	$ -
Dividends paid on common stock	(166,084)	(127,386)	(138,995)
Dividends paid on preferred stock	(1,206)	(2,075)	(2,574)
Changes in short-term debt	(111,250)	17,650	(31,550)
Long-term debt - issues	-	-	47,850
Long-term debt - retirements	(328,000)	(38,500)	(57,850)
Repurchase of common shares	(417,960)	-	-
Preferred stock - retirements	(38,505)	-	(19,532)
Premium on reacquisition of long-term debt	-	(2,163)	-
Net cash used in financing activities	$ (1,028,124)	$ (152,474)	$ (202,651)
Net increase (decrease) in cash and cash equivalents	$ 177,770	$ (1,403)	$ 439
Cash and cash equivalents at beginning of year	1,643	3,046	2,607
Cash and cash equivalents at end of year	$ 179,413	$ 1,643	$ 3,046
Supplementary Information:			
Interest paid less amounts capitalized	$ 43,419	$ 46,033	$ 51,212
Federal and state income taxes paid	$ 282,076	$ 109,109	$ 96,006
Dividends received from investments at equity	$ 6,571	$ 3,267	$ 4,313

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

New England Power Company
Notes to Financial Statements

Note A - Significant Accounting Policies

1. Nature of operations:

New England Power Company (the Company), a wholly owned subsidiary of New England Electric System (NEES), is a Massachusetts corporation and is qualified to do business in Massachusetts, New Hampshire, Rhode Island, Connecticut, Maine, and Vermont. The Company is subject, for certain purposes, to the jurisdiction of the regulatory commissions of these six states, the Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935 (1935 Act), the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). The Company's business is primarily the transmission of electric energy in wholesale quantities to other electric utilities, principally its distribution affiliates Granite State Electric Company, Massachusetts Electric Company (Massachusetts Electric), Nantucket Electric Company, and The Narragansett Electric Company (Narragansett Electric). See Note C for a discussion of industry restructuring and Note D for a discussion of the Company's divestiture of its nonnuclear generating business. The Company also owns minority interests in two joint owned nuclear generating units as well as minority equity interests in 4 nuclear generating companies. The output from these generating facilities is sold to third parties.

2. System of accounts:

The accounts of the Company are maintained in accordance with the Uniform System of Accounts prescribed by regulatory bodies having jurisdiction.

In preparing the financial statements, management is required to make estimates that affect the reported amounts of assets and liabilities and disclosures of asset recovery and contingent liabilities as of the date of the balance sheets, and revenues and expenses for the period. These estimates may differ from actual amounts if future circumstances cause a change in the assumptions used to calculate these estimates.

3. Allowance for funds used during construction (AFDC):

The Company capitalizes AFDC as part of construction costs. AFDC represents the composite interest and equity costs of capital funds used to finance that portion of construction costs not yet eligible for inclusion in rate base. AFDC is capitalized in "Utility plant" with offsetting noncash credits to "Other income" and "Interest." This method is in accordance with an established rate-making practice under which a utility is permitted a return on, and the recovery of, prudently incurred capital costs through their ultimate inclusion in rate base and in the provision for depreciation.

4. Depreciation and amortization:

The depreciation and amortization expense included in the statements of income is composed of the following:

Year ended December 31 (In thousands)	1998	1997	1996
Depreciation - transmission related	$ 12,553	$ 11,828	$ 10,931
Depreciation - all other	46,256	68,432	67,256
Nuclear decommissioning costs (Note E-2)	2,719	2,638	2,629
Amortization:			
Investment in Seabrook 1 pursuant to rate settlement	-	-	15,210
Seabrook 2 property losses	-	113	6,279
Millstone 3 additional amortization, pursuant to 1995 rate settlement	22,040	15,013	1,904
Regulatory assets covered by CTC (See Note C)	16,356	-	-
Total depreciation and amortization expense	$ 99,924	$ 98,024	$104,209

Depreciation is provided annually on a straight-line basis. The provision for depreciation as a percentage of weighted average depreciable transmission property was 2.3 percent in 1998, 1997, and 1996. Amortization of Seabrook and Millstone 3 investments above normal depreciation accruals was in accordance with rate settlement agreements.

5. Cash:

The Company classifies short-term investments with a maturity of 90 days or less as cash.

6. New Accounting Standards:

In 1997, the Financial Accounting Standards Board (FASB) released Statement of Financial Accounting Standards No. 130, Reporting of Comprehensive Income (FAS 130), which was adopted by the Company in the first quarter of 1998. FAS 130 establishes standards for reporting comprehensive income and its components. Comprehensive income for the period is equal to net income plus "other comprehensive income," which for the Company, consists of the change in unrealized holding gains on available-for-sale securities during the period. Other comprehensive income was immaterial for the Company for the year ended December 31, 1998.

Also in 1997, the FASB released Statement of Financial Accounting Standards No. 131, Disclosure about Segments of an Enterprise and Related Information (FAS 131), which went into effect in 1998. FAS 131 requires the reporting in financial statements of certain new additional information about operating segments of a business. FAS 131 does not currently impact the Company's reporting requirements.

In February 1998, the FASB issued Statement of Financial Accounting Standards No. 132, Employers' Disclosures about Pensions and Other Postretirement Benefits (FAS 132), which revises disclosure requirements for pension and other postretirement benefits. The Company has adopted FAS 132 in its financial statements for the year ending December 31, 1998.

The adoption of FAS 130, FAS 131, and FAS 132 had no impact on the Company's operating results, financial position, or cash flows.

In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), which establishes accounting and reporting standards for such instruments. FAS 133 is effective for fiscal years beginning after June 15, 1999. Currently, the Company has no such derivative holdings.

Note B - Merger Agreements

Merger Agreement with The National Grid Group plc

On December 11, 1998, NEES, The National Grid Group plc (National Grid), and NGG Holdings LLC (Holdings), a directly and indirectly wholly owned subsidiary of National Grid, entered into an Agreement and Plan of Merger (Merger Agreement). Pursuant to the Merger Agreement, Holdings will merge with and into NEES (the Merger), with NEES becoming a wholly owned subsidiary of National Grid. The Company will remain a wholly owned subsidiary of NEES.

The Merger is subject to approval by a majority vote of NEES shareholders as well as National Grid shareholder approval. In addition, the Merger is subject to a number of regulatory and other approvals and consents, including approvals by the SEC, under the 1935 Act, FERC and NRC, support or approval from the states in which NEES subsidiaries operate, and clearance under both the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the Exon-Florio Provisions of the Omnibus Trade and Competitiveness Act of 1988. National Grid has obtained governmental clearance in the United Kingdom for the Merger. The Merger is expected to be completed by early 2000.

Merger Agreement with Eastern Utilities Associates

On February 1, 1999, NEES, Eastern Utilities Associates (EUA), and Research Drive LLC (Research Drive), a directly and indirectly wholly owned subsidiary of NEES, entered into an Agreement and Plan of Merger (EUA Agreement). Pursuant to the EUA Agreement, Research Drive will merge with and into EUA, with EUA becoming a wholly owned subsidiary of NEES.

The acquisition of EUA is subject to approval by a two-thirds vote of EUA shareholders. In addition, the acquisition is subject to a number of regulatory and other approvals and consents, including approvals by the SEC, under the 1935 Act, FERC, and NRC, support or approval from the states in which EUA subsidiaries operate, and clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. The EUA acquisition is expected to be completed by early 2000. Following the acquisition of EUA, the subsidiaries of NEES and EUA whose operations are similar are expected to be consolidated.

Note C - Industry Restructuring

During 1998, pursuant to legislation enacted in Massachusetts, Rhode Island, and New Hampshire, and settlement agreements approved by state and federal regulators (the Settlement Agreements), all customers were provided the right to purchase electricity from the power supplier of their choice. The NEES companies remain obligated to deliver that electricity over its transmission and distribution systems, with such delivery services provided under regulated rates approved by State and federal regulators. As described below, those delivery rates include a non-bypassable charge for the costs of NEES' former generating business which were not recovered through the sale of that business ("stranded costs"), which was substantially completed in 1998. As a result of the Settlement Agreements, customers' choice of power supplier has no impact on NEES' transmission and distribution business or on its ability to recover stranded costs. In order to facilitate the implementation of customer choice, the Settlement Agreements provided for the termination of the Company's requirements contracts with its affiliated distribution customers. The Company's requirements contracts with unaffiliated customers have also generally been terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service to new customer load in Rhode Island.

The Settlement Agreements provide that the Company's stranded costs are to be recovered from its wholesale customers through contract termination charges (CTC). The affiliated wholesale customers, in turn, are recovering those costs through their delivery charges to distribution customers. Under the Settlement Agreements, the recovery of the Company's stranded costs is divided into several categories. Unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets will be fully recovered through the CTC by the end of 2000 and earn a return on equity averaging 9.7 percent. The Company's obligation relating to the above-market cost of purchased power contracts and nuclear decommissioning costs are recovered through the CTC over a longer period of time, as such costs are actually incurred. The CTC rate was originally set at 2.8 cents per kilowatthour (kWh), and subsequently reduced to approximately 1.5 cents or less per kWh upon completion of the sale of the Company's nonnuclear generating business. As the CTC rate declines, the Company, under certain of the Settlement Agreements, earns incentives based on successful mitigation of its stranded costs. These incentives supplement the Company's return on equity. Finally, the Settlement Agreements provide that until such time as the Company divests its operating nuclear interests, the Company will share with customers, through the CTC, 80 percent of the revenues and operating costs related to the units, with shareholders retaining the balance.

Accounting Implications

Historically, electric utility rates have been based on a utility's costs. As a result, electric utilities are subject to certain accounting standards that are not applicable to other business enterprises in general. Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71), requires regulated entities, in appropriate circumstances, to establish regulatory assets, and thereby defer the income statement impact of these charges because they are expected to be included in future customer charges. In 1997, the Emerging Issues Task Force (EITF) of the FASB concluded that a utility that had received approval to recover stranded costs through regulated transmission and distribution rates would be permitted to continue to apply FAS 71 to the recovery of stranded costs.

The Company has received authorization from the FERC to recover through the CTC substantially all of the costs associated with its former generating business not recovered through the sale of that business. Additionally, FERC Order No. 888 enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of the Company's business, including the recovery of its stranded costs, remains under cost-based rate regulation. The Company believes these factors and the EITF conclusion allow it to continue to apply FAS 71. Because of the nuclear cost-sharing provisions related to the Company's CTC, the Company ceased applying FAS 71 in 1997 to 20 percent of its ongoing nuclear operations, the impact of which is immaterial.

Currently, there is much regulatory and other movement toward establishing performance-based rates. It is possible that the adoption of performance-based rates for the Company or its affiliates, future regulatory rules, or other circumstances could cause the application of FAS 71 to be discontinued. This discontinuation would result in a noncash write-off of previously established regulatory assets, including those being recovered through the Company's CTC.

As a result of applying FAS 71, the Company has recorded a regulatory asset for the costs that are recoverable from customers through the CTC. The regulatory asset reflects the loss on the sale of NEES' oil and gas business and the unrecovered plant costs in operating nuclear plants (assuming no market value), the costs associated with permanently closed nuclear power plants, and the present value of the payments associated with the above-market cost of purchased power contracts, reduced by the gain from the sale of the nonnuclear generating business. At December 31, 1998, the regulatory asset related to the CTC was approximately $1.5 billion, of which $1.2 billion related to the above-market costs of purchased power contracts.

As described above, the CTC regulatory asset includes the unrecovered plant costs associated with the Company's interest in operating nuclear plants. This balance sheet treatment is due to the Company's conclusion that its interests in the Millstone 3 and Seabrook 1 nuclear generating units have little, if any, market value. Three proposed sales of nuclear units by other utilities have required the seller to set aside amounts for decommissioning in excess of the proceeds from the sale of the units. Two of these proposed sales were agreed upon prior to the end of the third quarter of 1998. As a result, at the end of the third quarter of 1998, the Company recorded an impairment writedown in its reserve for depreciation of approximately $390 million, which represents the net book value at December 31, 1995, less applicable depreciation subsequent to that date, of Millstone 3 and Seabrook 1. Because the Settlement Agreements permit the Company to recover its pre-1996 investment as well as decommissioning expenses through the CTC, the Company established a regulatory asset in an amount equal to the impairment writedown. Should the Company's efforts to sell its nuclear interests result in a gain over the amounts remaining in the plant account, such gain will be credited to customers through the CTC.

Note D - Divestiture of Generating Business

On September 1, 1998, the Company and Narragansett Electric (collectively, the Sellers) completed the sale of substantially all of their nonnuclear generating business, all of which had a book value of approximately $1.1 billion, to USGen New England, Inc. (USGen), an indirect wholly owned subsidiary of PG&E Corporation. The Sellers received $1.59 billion for the sale. In addition, the Company was reimbursed approximately $140 million for costs associated with early retirements and special severance programs for employees affected by industry restructuring, and the value of inventories. USGen assumed responsibility for environmental conditions at the Sellers' nonnuclear generating stations. USGen also assumed the Sellers' obligations under long-term fuel and fuel transportation contracts, and certain collective bargaining agreements.

As part of the sale, the Company also signed a purchased power transfer agreement through which USGen purchased the Company's entitlement to approximately 1,100 megawatts (MW) of power procured under long-term contracts in exchange for monthly fixed payments by the Company averaging $9.5 million per month through January 2008 (having a net present value of $833 million) toward the above-market cost of those contracts. In some cases, these transfers involved formal assignment of the contracts to USGen and a release of the Company from further obligations to the power supplier, while others did not. For those that involved formal assignment, the Company was required to make a lump sum payment equivalent to the present value of the monthly fixed payment obligations of those contracts. On or prior to the closing date, the Company made lump sum payments totaling approximately $340 million and was released from further obligations relating to two of the contracts. These lump sum payments are separate from the $833 million figure referred to above. USGen is responsible for the balance of the costs under the purchased power contracts. The present value of the future monthly fixed payments is recorded as a liability on the balance sheet. This liability, as well as the lump sum payments previously made, net of amortization, are also recorded as a regulatory asset on the balance sheet.

As part of the divestiture plan, in February 1998, New England Energy Incorporated (NEEI), a wholly owned subsidiary of NEES, whose costs had been supported by the Company, sold its oil and gas properties for approximately $50 million. NEEI's loss on the sale of approximately $120 million, before tax, has been reimbursed by the Company.

In addition, the Company agreed under the Settlement Agreements to endeavor to sell its minority interest in three nuclear power plants and a 60 MW interest in a fossil-fueled generating station in Maine. In February 1999, Vermont Yankee Nuclear Power Corporation entered into a letter of intent to sell its assets. For further information refer to the "Nuclear Units" section of Financial Review.

Note E - Commitments and Contingencies

1. Yankee Nuclear Power Companies (Yankees):

The Company has minority interests in four Yankee Nuclear Power Companies. These ownership interests are accounted for on the equity method. The Company's share of the expenses of the Yankees is accounted for in "Purchased electric energy" on the statements of income.

A summary of combined results of operations, assets, and liabilities of the four Yankees is as follows:

(In thousands)	**1998**	1997	1996
Operating revenue	**$ 439,046**	$ 660,742	$ 697,054
Net income	**$ 23,218**	$ 29,959	$ 27,567
Company's equity in net income	**$ 5,284**	$ 5,189	$ 5,159
Net plant	**171,582**	204,689	401,049
Other assets	**2,810,613**	3,100,589	2,031,336
Liabilities and debt	**(2,723,454)**	(3,036,845)	(2,177,068)
Net assets	**$ 258,741**	$ 268,433	$ 255,317
Company's equity in net assets	**$ 48,538**	$ 49,825	$ 47,902
Company's purchased electric energy:			
Vermont Yankee	**$ 35,108**	$ 31,240	$ 32,676
All other Yankees	**$ 48,543**	$ 75,900	$ 78,102

At December 31, 1998, $15 million of undistributed earnings of the Yankees were included in the Company's retained earnings.

2. Nuclear Units:

Nuclear Units Permanently Shut Down

Three regional nuclear generating companies in which the Company has a minority interest own nuclear generating units that have been permanently shut down. These three units are as follows:

Unit	NEP's Investment %	NEP's Investment $ (millions)	Date Retired	Future Estimated Billings to NEP $(millions)
Yankee Atomic	30	6	Feb 1992	24
Connecticut Yankee	15	16	Dec 1996	75
Maine Yankee	20	16	Aug 1997	143

In the case of each of these units, the Company has recorded a liability and an offsetting regulatory asset reflecting the estimated future billings from the companies. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant as well as unfunded nuclear decommissioning costs and other costs. Connecticut Yankee and Maine Yankee have both filed similar requests with the FERC. Several parties have intervened in opposition to both filings. In August 1998, a FERC Administrative Law Judge (ALJ) issued an initial decision which would allow for full recovery of Connecticut Yankee's unrecovered investment, but precluded a return on that investment. Connecticut Yankee, the Company, and other parties have filed with the FERC exceptions to the ALJ's decision. Should the FERC uphold the ALJ's initial decision in its current form, the Company's share of the loss of the return component would total approximately $12 million to $15 million before taxes. In January 1999, parties in the Maine Yankee proceeding filed a comprehensive settlement agreement with the FERC, under which Maine Yankee would recover all unamortized investment in the plant, including a return on its equity investment of 6.5 percent, as well as decommissioning costs and other costs. This settlement agreement requires FERC approval. The Company's industry restructuring settlements allow it to recover all costs that the FERC allows these Yankee companies to bill to the Company.

The Company and several other shareholders (Sponsors) of Maine Yankee are parties to 27 contracts (Secondary Purchase Agreements) under which they sold portions of their entitlements to Maine Yankee power output through 2002 to various entities, primarily municipal and cooperative systems in New England (Secondary Purchasers). Virtually all of the Secondary Purchasers had ceased making payments under the Secondary Purchase Agreements, claiming that such agreements excuse further payments upon plant shutdown. In February 1999, a settlement agreement which fully resolves the dispute between the Sponsors and Secondary Purchasers was filed with the FERC, under which the Secondary Purchasers would be required to make certain payments to Maine Yankee, and, in turn, to the Company, related to both past and future obligations under the Secondary Purchase Agreements. This settlement agreement requires FERC approval. Shutdown costs are recoverable from customers under the Settlement Agreements.

A Maine statute provides that if both Maine Yankee and its decommissioning trust fund have insufficient assets to pay for the plant decommissioning, the owners of Maine Yankee are jointly and severally liable for the shortfall.

Operating Nuclear Units

The Company has minority interests in three other nuclear generating units: Vermont Yankee, Millstone 3, and Seabrook 1. Uncertainties regarding the future of nuclear generating stations, particularly older units, such as Vermont Yankee, are increasing rapidly and could adversely affect their service lives, availability, and costs. These uncertainties stem from a combination of factors, including the acceleration of competitive pressures in the power generation industry and increased NRC scrutiny. The Company performs periodic economic viability reviews of operating nuclear units in which it holds ownership interests.

Vermont Yankee

On February 25, 1999, the Board of Directors of Vermont Yankee Nuclear Power Corporation granted an exclusive right to AmerGen Energy Company (AmerGen), a joint venture by PECO Energy and British Energy to conduct a due diligence review over the next 120 days and negotiate a possible agreement to purchase the assets of Vermont Yankee, Vermont's sole nuclear generating plant. Provided the due diligence review leads to successful completion of negotiations for a sale, consummation of such a sale would be contingent on regulatory approvals by the NRC, the SEC, under the 1935 Act, and the Vermont Public Service Board, among others. The sale process could take eight to twelve months or longer. In past negotiations for the sale of nuclear plants, due diligence review has not guaranteed that a sale will occur. The Company has a 20 percent ownership interest in Vermont Yankee and an investment of approximately $11 million at December 31, 1998.

Millstone 3

In July 1998, Millstone 3 returned to full operation after being shut down since April 1996. Millstone 3 remains on the NRC "Watch List," signifying that it continues to warrant increased NRC attention. Millstone 3 is operated by a subsidiary of Northeast Utilities (NU). The Company is not an owner of the Millstone 2 nuclear generating unit, which is temporarily shut down under NRC orders, or the Millstone 1 nuclear generating unit, which has been permanently shut down. A criminal investigation related to Millstone 3 is ongoing.

In August 1997, the Company sued NU in Massachusetts Superior Court for damages resulting from the tortious conduct of NU that caused the shutdown of Millstone 3. The Company's damages include the costs of replacement power during the outage, costs necessary to return Millstone 3 to safe operation, and other additional costs. Most of the Company's incremental replacement power costs have been recovered from customers, either through fuel adjustment clauses or through provisions in the Settlement Agreements. The Company also seeks punitive damages. The Company also sent a demand for arbitration to Connecticut Light & Power Company and Western Massachusetts Electric Company, both subsidiaries of NU, seeking damages resulting from their breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3. The arbitration is scheduled for October 1999. In July 1998, the court denied NU's motion to dismiss and its motion to stay pending arbitration. The Company subsequently amended its complaint by, among other things, adding NU's Trustees as defendants. In December 1998, NU moved for summary judgement. The Company's suit has been consolidated with suits filed by other joint owners. The court is in the process of scheduling a trial date. Some or all of the damages awarded from the lawsuit would be refunded to customers.

Nuclear Decommissioning

The Company is liable for its share of decommissioning costs for Millstone 3, Seabrook 1, and all of the Yankees. Decommissioning costs include not only estimated costs to decontaminate the units as required by the NRC, but also costs to dismantle the uncontaminated portion of the units. The Company records decommissioning costs on its books consistent with its rate recovery. The Company is recovering its share of projected decommissioning costs for Millstone 3 and Seabrook 1 through depreciation expense. In addition, the Company is paying its portion of projected decommissioning costs for all of the Yankees through purchased power expense. Such costs reflect estimates of total decommissioning costs approved by the FERC.

In New Hampshire, legislation was recently enacted which makes owners of Seabrook 1, in which the Company owns a 10 percent interest, proportional guarantors for decommissioning costs in the event that an owner without a franchise service territory fails to fund its share of decommissioning costs. Currently, a single owner of an approximate 12 percent share of Seabrook 1 has no franchise service territory.

The New Hampshire Nuclear Decommissioning Finance Committee is reviewing Seabrook Station's decommissioning estimate and associated annual funding levels. Among the items being considered is the imposition of joint and several liability among the Seabrook joint owners for decommissioning funding. The Company cannot predict what additional liability, if any, may be imposed on it.

The Nuclear Waste Policy Act of 1982 establishes that the federal government (through the Department of Energy (DOE)) is responsible for the disposal of spent nuclear fuel. The federal government requires the Company to pay a fee based on its share of the net generation from the Millstone 3 and Seabrook 1 nuclear generating units. Prior to 1998, the Company recovered this fee through its fuel clause. Under the Settlement Agreements, substantially all of these costs are recovered through CTCs. Similar costs are billed to the Company by Vermont Yankee and also recovered from customers through the same mechanism. In November 1997, ruling on a lawsuit brought against the DOE by numerous utilities and state regulatory commissions, the U.S. Court of Appeals for the District of Columbia (the Appeals Court) held that the DOE was obligated to begin disposing of utilities' spent nuclear fuel by January 31, 1998. The DOE failed to meet this deadline, and is not expected to have a temporary or permanent repository for spent nuclear fuel for many years. In February 1998, Maine Yankee petitioned the Appeals Court to compel the DOE to remove Maine Yankee's spent fuel from the site. In May 1998, the Appeals Court rejected the petitions of Maine Yankee and the other utilities and state regulatory commissions, stating that the issue of damages was a contractual matter. The operators of the units in which the Company has an obligation, including Maine Yankee, Connecticut Yankee, and Yankee Atomic, continue to pursue damage claims against the DOE in the Federal Court of Claims (Claims Court). In October 1998, the Claims Court ruled that the DOE violated a commitment to remove spent fuel from Yankee Atomic. The Claims Court issued similar rulings in November 1998 related to cases brought by Connecticut Yankee and Maine Yankee. Further proceedings will be scheduled by the Claims Court to decide the amount of damages.

Decommissioning Trust Funds

Each nuclear unit in which the Company has an ownership interest has established a decommissioning trust fund or escrow fund into which payments are being made to meet the projected costs of decommissioning. The table below lists information on each operating nuclear plant in which the Company has an ownership interest.

		NEP's share of (millions of dollars)			
Unit	Nep's Ownership Interest (%)	Net Plant Assets	Estimated Decommissioning Cost (in 1998 $)	Decommissioning Fund Balances*	License Expiration
Vermont Yankee	20	34	105	38	2012
Millstone 3	12	9**	67	21	2025
Seabrook 1	10	15**	50	10	2026

* Certain additional amounts are anticipated to be available through tax deductions.

** Represents post-December 1995 spending including nuclear fuel. See Note C for a discussion of an impairment writedown and establishment of an offsetting regulatory asset.

There is no assurance that decommissioning costs actually incurred by Vermont Yankee, Millstone 3, or Seabrook 1 will not substantially exceed these amounts. For example, decommissioning cost estimates assume the availability of permanent repositories for both low-level and high-level nuclear waste; those repositories do not currently exist. The temporary low-level repository located in Barnwell, South Carolina may become unavailable, which could increase the cost of decommissioning the Yankee Atomic, Connecticut Yankee, and Maine Yankee plants. If any of the operating units were shut down prior to the end of their operating licenses, which the Company believes is likely, the funds collected for decommissioning to that point would be insufficient. Under the Settlement Agreements discussed in Note C, the Company will recover decommissioning costs through CTCs.

Nuclear Insurance

The Price-Anderson Act limits the amount of liability claims that would have to be paid in the event of a single incident at a nuclear plant to $9.7 billion (based upon 108 licensed reactors). The maximum amount of commercially available insurance coverage to pay such claims is $200 million. The remaining $9.5 billion would be provided by an assessment of up to $88.1 million per incident levied on each of the participating nuclear units in the United States, subject to a maximum assessment of $10 million per incident per nuclear unit in any year. The maximum assessment, which was most recently adjusted in 1998, is adjusted for inflation at least every five years. The Company's current interest in Vermont Yankee, Millstone 3, and Seabrook 1 would subject the Company to a $35.4 million maximum assessment per incident. The Company's payment of any such assessment would be limited to a maximum of $4.0 million per year. As a result of the permanent cessation of power operation of the Yankee Atomic, Connecticut Yankee, and Maine Yankee plants, these units have received from the NRC an exemption from participating in the secondary financial protection system under the Price-Anderson Act. However, these plants must continue to maintain $100 million of commercially available nuclear liability insurance coverage.

Each of the nuclear units in which the Company has either an ownership or purchased power interest also carries nuclear property insurance to cover the costs of property damage, decontamination, and premature decommissioning resulting from a nuclear incident. These policies may require additional premium assessments if losses relating to nuclear incidents at units covered by this insurance occur in a prior six-year period. The Company's maximum potential exposure for these assessments, either directly or indirectly, is approximately $4.6 million with respect to the current policy period.

3. Plant expenditures:

The Company's utility plant expenditures are estimated to be approximately $65 million in 1999. At December 31, 1998, substantial commitments had been made relative to future planned expenditures.

4. Hydro-Quebec Interconnection:

Three affiliates of the Company were created to construct and operate transmission facilities to transmit power from Hydro-Quebec to New England. Under support agreements entered into at the time these facilities were constructed, the Company agreed to guarantee a portion of the project debt. That portion at December 31, 1998 amounted to $23 million.

5. Long-term contracts for the purchase of electricity:

Historically, the Company purchased a portion of its electricity requirements pursuant to long-term contracts with owners of various generating units. These contracts expire in various years from 1998 to 2029. See Note D for a discussion of USGen's purchase of the Company's entitlement to approximately 1,100 MW of power procured under long-term contracts.

The Company retained one purchased power contract, with Vermont Yankee, which requires minimum fixed payments, even when the supplier is unable to deliver power, to cover a proportionate share of the capital and fixed operating costs of the unit. This contract has fixed payment requirements of approximately $35 million in 1999, $30 million in 2000, $35 million in 2001 and 2002, $30 million in 2003, and approximately $300 million thereafter. The Company holds an ownership interest in Vermont Yankee.

6. Hazardous waste:

The Federal Comprehensive Environmental Response, Compensation and Liability Act, more commonly known as the "Superfund" law, imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. A number of states, including Massachusetts, have enacted similar laws.

The electric utility industry typically utilizes and/or generates in its operations a range of potentially hazardous products and by-products. The Company currently has in place an internal environmental audit program and an external waste disposal vendor audit and qualification program intended to enhance compliance with existing federal, state, and local requirements regarding the handling of potentially hazardous products and by-products.

The Company has been named as a potentially responsible party (PRP) by either the United States Environmental Protection Agency or the Massachusetts Department of Environmental Protection for six sites at which hazardous waste is alleged to have been disposed. Private parties have also contacted or initiated legal proceedings against the Company regarding hazardous waste cleanup. The Company is currently aware of other possible hazardous waste sites, and may in the future become aware of additional sites, that they may be held responsible for remediating.

Predicting the potential costs to investigate and remediate hazardous waste sites continues to be difficult. There are also significant uncertainties as to the portion, if any, of the investigation and remediation costs of any particular hazardous waste site that may ultimately be borne by the Company. The NEES companies have recovered amounts from certain insurers, and, where appropriate, intend to seek recovery from other insurers and from other PRPs, but it is uncertain whether, and to what extent, such efforts will be successful. The Company believes that hazardous waste liabilities for all sites of which it is aware are not material to its financial position.

7. Town of Norwood dispute:

In September 1998, the United States District Court (District Court) for the District of Massachusetts dismissed the lawsuit filed in April 1997 by the Town of Norwood, Massachusetts against NEES and the Company. The Company had been a wholesale power supplier for Norwood pursuant to rates approved by the FERC. In the lawsuit, Norwood had alleged that the Company's divestiture of its power generating assets would violate the terms of a 1983 power contract. Norwood also alleged that the divestiture and recovery of stranded investment costs contravened federal antitrust laws. The District Court judge granted NEES' and the Company's motion for dismissal on the grounds that the contract did not require the Company to retain its generating units, that the FERC-approved filed rates govern these matters, and that Norwood had adequate opportunity at the FERC to litigate these matters. Norwood filed a motion to alter or amend the order of dismissal, which was denied. In December 1998, Norwood filed a second motion to amend judgement and also filed an appeal with the First Circuit Court of Appeals (First Circuit). In March 1999, the District Court denied Norwood's second motion to amend judgement.

In March 1998, Norwood gave notice of its intent to terminate its contract with the Company, without accepting responsibility for its share of the Company's stranded costs, and began taking power from another supplier commencing in April 1998. In May 1998, the FERC ruled that the Company could assess a CTC to any of the Company's unaffiliated customers that choose to terminate their wholesale power contracts early. Norwood claimed that the CTC approved by the FERC did not apply to Norwood; however, in denying Norwood's motion for rehearing, the FERC ruled that the charge did apply to Norwood. Norwood has appealed this decision to the First Circuit. The Company's billings to Norwood for this charge through December 1998 have been approximately $6 million, which remain unpaid. The Company filed a collection action with the Massachusetts Superior Court in December 1998 to recover these amounts. Norwood filed a motion to dismiss or stay in January 1999.

Norwood also appealed the FERC's orders approving the divestiture and the Massachusetts and Rhode Island industry restructuring settlement agreements (including modification of the Company's contracts with Massachusetts Electric and Narragansett Electric) to the First Circuit, despite the FERC's finding that those settlement agreements do not apply to Norwood.

The First Circuit has consolidated all three of Norwood's appeals from the FERC's orders with two other appeals filed by the Northeast Center for Social Issue Studies, which challenge the FERC's approval of the Company's sale of its hydroelectric facilities. The case is to be fully briefed by May 1999.

Note F - Employee Benefits

1. Pension Plans:

The Company participates with other subsidiaries of NEES in noncontributory, defined-benefit plans covering substantially all employees of the Company. The plans provide pension benefits based on the employee's compensation during the five years prior to retirement. Absent unusual circumstances, the Company's funding policy is to contribute each year the net periodic pension cost for that year. However, the contribution for any year will not be less than the minimum contribution required by federal law or greater than the maximum tax deductible amount.

Net pension cost for 1998, 1997, and 1996 included the following components:

Year ended December 31 (thousands of dollars)	**1998**	1997	1996
Service cost - benefits earned during the period	**$ 2,430**	$ 2,887	$ 2,769
Plus (less):			
Interest cost on projected benefit obligation	**7,435**	7,003	6,669
Return on plan assets at expected long-term rate	**(8,675)**	(7,842)	(7,204)
Amortization of transition obligation	**(184)**	(175)	(171)
Amortization of prior service cost	**161**	171	168
Amortization of net (gain)/loss	**159**	65	273
Curtailment (gain)/loss	**(5,680)**	-	-
Benefit cost	**$ (4,354)**	$ 2,109	$ 2,504
Special termination benefits not included above	**$ 10,911**	$ -	$ -

The funded status of the plans cannot be presented separately for the Company as the Company participates in the plans with other NEES subsidiaries. The following table sets forth the funded status of the NEES companies' plans at December 31:

(millions of dollars)	**1998**	1997
Benefit obligation	**$ 843**	$ 819
Unrecognized prior service costs	**(6)**	(8)
Transition liability not yet recognized (amortized)	**(2)**	(4)
Additional minimum liability	**7**	4
	842	811
Plan assets at fair value	**837**	834
Transition asset not yet recognized (amortized)	**(6)**	(8)
Net (gain)/loss not yet recognized (amortized)	**(92)**	(52)
	739	774
Accrued pension/(prepaid) payments recorded on books	**$ 103**	$ 37

The following provides a reconciliation of benefit obligations and plan assets:

(millions of dollars)	1998	1997
Changes in benefit obligation:		
Benefit obligation at January 1	$ 819	$ 807
Service cost	14	15
Interest cost	55	53
Actuarial (gain)/loss	(5)	59
Benefits paid from plan assets	(94)	(47)
Special termination benefits	64	-
Curtailment	(11)	-
Plan amendments	1	-
Dispositions (Yankee Atomic)	-	(68)
Benefit obligation at December 31	$ 843	$ 819
Reconciliation of change in plan assets:		
Fair value of plan assets at January 1	$ 834	$ 812
Actual return on plan assets during year	93	130
Company contributions	4	8
Benefits paid from plan assets	(94)	(47)
Dispositions (Yankee Atomic)	-	(69)
Fair value of plan assets at December 31	$ 837	$ 834

Year ended December 31	1999	1998	1997	1996
Assumptions used to determine pension cost:				
Discount rate	6.75%	6.75%	7.25%	7.25%
Average rate of increase in future compensation level	4.13%	4.13%	4.13%	4.13%
Expected long-term rate of return on assets	8.50%	8.50%	8.50%	8.50%

The plans' funded status at December 31, 1998 and 1997 were calculated using the assumed rates from 1999 and 1998, respectively, and the 1983 Group Annuity Mortality table.

Plan assets are composed primarily of corporate equity, debt securities, and cash equivalents.

2. Postretirement Benefit Plans Other than Pensions (PBOPs):

The Company provides health care and life insurance coverage to eligible retired employees. Eligibility is based on certain age and length of service requirements and in some cases retirees must contribute to the cost of their coverage.

The Company's total cost of PBOPs for 1998, 1997, and 1996 included the following components:

Year ended December 31 (thousands of dollars)	**1998**	1997	1996
Service cost - benefits earned during the period	**$ 1,109**	$ 1,363	$ 1,407
Plus (less):			
Interest cost on projected benefit obligation	**3,244**	3,545	3,580
Return on plan assets at expected long-term rate	**(2,656)**	(2,343)	(1,832)
Amortization of transition obligation	**1,732**	2,556	2,556
Amortization of prior service cost	**5**	8	8
Amortization of net (gain)/loss	**(1,138)**	(983)	(697)
Curtailment (gain)/loss	**27,149**	-	-
Benefit cost	**$ 29,445**	$ 4,146	$ 5,022
Special termination benefits not included above	**$ 439**	$ -	$ -

The following table sets forth the Company's benefits earned and the plans' funded status:

At December 31 (millions of dollars)	**1998**	1997
Benefit obligation	**$ 41**	$ 51
Unrecognized prior service costs	**-**	-
Transition liability not yet recognized (amortized)	**(1)**	(38)
	40	13
Plan assets at fair value	**36**	34
Net (gain)/loss not yet recognized (amortized)	**(26)**	(21)
	10	13
Accrued pension/(prepaid) payments recorded on books	**$ 30**	$ -

The following provides a reconciliation of benefit obligations and plan assets:

(millions of dollars)	**1998**	1997
Changes in benefit obligation:		
Benefit obligation at January 1	**$ 51**	$ 54
Service cost	**1**	1
Interest cost	**3**	4
Actuarial (gain)/loss	**2**	(6)
Benefits paid from plan assets	**(2)**	(2)
Special termination benefits	**-**	-
Curtailment	**(14)**	-
Benefit obligation at December 31	**$ 41**	$ 51
Reconciliation of change in plan assets:		
Fair value of plan assets at January 1	**$ 34**	$ 29
Actual return on plan assets during year	**4**	6
Company contributions	**-**	1
Benefits paid from plan assets	**(2)**	(2)
Fair value of plan assets at December 31	**$ 36**	$ 34

Year ended December 31	1999	1998	1997	1996
Assumptions used to determine postretirement benefit cost:				
Discount rate	6.75%	6.75%	7.25%	7.25%
Expected long-term rate of return on asset	8.25%	8.25%	8.25%	8.25%
Health care cost rate - 1996 to 1999	5.25%	5.25%	8.00%	8.00%
Health care cost rate - 2000 to 2004	5.25%	5.25%	6.25%	6.25%
Health care cost rate - 2005 and beyond	5.25%	5.25%	5.25%	5.25%

The plans' funded status at December 31, 1998 and 1997 were calculated using the assumed rates in effect for 1999 and 1998, respectively.

The assumptions used in the health care cost trends have a significant effect on the amounts reported. A one percentage point change in the assumed rates would increase the accumulated postretirement benefit obligation (APBO) as of December 31, 1998 by approximately $5 million or decrease the APBO by approximately $4 million, and change the net periodic cost for 1998 by approximately $1 million.

The Company generally funds the annual tax-deductible contributions. Plan assets are invested in equity and debt securities and cash equivalents.

3. Early Retirement and Special Severance Programs:

In 1998, the Company offered a voluntary early retirement program to all employees who were at least 55 years old with 10 years of service. This program was part of an organizational review with the goal of streamlining operations and reducing the work force to reflect the sale of the nonnuclear generating business. The early retirement offer was accepted by 104 employees. A special severance program was also utilized in 1998 for employees affected by the organizational restructuring, but who were not eligible for, or did not accept, the early retirement offer. The cost of these programs was in part reimbursed by USGen at the closing of the sale of the nonnuclear generating business and will be recovered in part from customers as a component of stranded cost recovery.

Note G - Income Taxes

The Company and other subsidiaries participate with NEES in filing consolidated federal income tax returns. The Company's income tax provision is calculated on a separate return basis. Federal income tax returns have been examined and reported on by the Internal Revenue Service through 1993.

Total income taxes in the statements of income are as follows:

Year ended December 31 (In thousands)	**1998**	1997	1996
Income taxes charged to operations	**$ 73,594**	$ 90,009	$ 91,894
Income taxes charged (credited) to "Other income"	**(19,582)**	(373)	555
Total income taxes	**$ 54,012**	$ 89,636	$ 92,449

Total income taxes, as shown above, consist of the following components:

Year ended December 31 (In thousands)	**1998**	1997	1996
Current income taxes	**$ 280,734**	$102,364	$ 99,907
Deferred income taxes	**(204,129)**	(10,705)	(5,435)
Investment tax credits, net	**(22,593)**	(2,023)	(2,023)
Total income taxes	**$ 54,012**	$ 89,636	$ 92,449

Investment tax credits (ITC) have been deferred and amortized over the estimated lives of the property giving rise to the credits. The increase in amortization of ITC in 1998 results from the recognition in income of unamortized ITC relating to the generating assets divested during 1998.

Total income taxes, as shown above, consist of federal and state components as follows:

Year ended December 31 (In thousands)	**1998**	1997	1996
Federal income taxes	**$ 41,255**	$73,077	$76,656
State income taxes	**12,757**	16,559	15,793
Total income taxes	**$ 54,012**	$89,636	$92,449

With regulatory approval from the FERC, the Company has adopted comprehensive interperiod tax allocation (normalization) for temporary book/tax differences.

Total income taxes differ from the amounts computed by applying the federal statutory tax rates to income before taxes. The reasons for the differences are as follows:

Year ended December 31 (In thousands)	**1998**	1997	1996
Computed tax at statutory rate	**$ 61,917**	$81,963	$85,726
Increases (reductions) in tax resulting from:			
Amortization of investment tax credits	**(15,157)**	(2,023)	(2,023)
State income taxes, net of federal income tax benefit	**8,292**	10,763	10,265
All other differences	**(1,040)**	(1,067)	(1,519)
Total income taxes	**$ 54,012**	$89,636	$92,449

The following table identifies the major components of total deferred income taxes:

At December 31 (In millions)	**1998**	1997
Deferred tax asset:		
Plant related	**$ 76**	$ 87
Investment tax credits	**13**	22
All other	**24**	44
	113	153
Deferred tax liability:		
Plant related	**(22)**	(418)
Equity AFDC	**(31)**	(43)
All other	**(225)**	(62)
	(278)	(523)
Net deferred tax liability	**$ (165)**	$ (370)

Note H - Short-term Borrowings and Other Accrued Expenses

At December 31, 1998, the Company had no short-term debt outstanding. NEES and certain subsidiaries, including the Company, with regulatory approval, operate a money pool to more effectively utilize cash resources and to reduce outside short-term borrowings. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowing companies pay interest at a rate designed to approximate the cost of outside short-term borrowings. Companies which invest in the pool share the interest earned on a basis proportionate to their average monthly investment in the money pool. Funds may be withdrawn from or repaid to the pool at any time without prior notice.

At December 31, 1998, the Company had lines of credit and standby bond purchase facilities with banks totaling $455 million. These lines and facilities were used at December 31, 1998 for liquidity support for $372 million of the Company's bonds in tax-exempt commercial paper mode (see Note J) and for other corporate purposes. There were no borrowings under these lines of credit at December 31, 1998. Fees are paid on the lines and facilities in lieu of compensating balances.

The components of other accrued expenses are as follows:

At December 31 (In thousands)	1998	1997
Accrued wages and benefits	$ 3,059	$ 9,838
Capital lease obligations due within one year	-	4,333
Rate adjustment mechanisms	16,781	6,957
Other	246	2,426
	$ 20,086	$ 23,554

Note I - Cumulative Preferred Stock

A summary of cumulative preferred stock at December 31, 1998 and 1997 is as follows (in thousands of dollars except for share data):

	Shares Outstanding		Amount		Dividends Declared		Call Price
	1998	1997	1998	1997	1998	1997	
$100 par value							
6.00% Series	15,672	75,020	$ 1,567	$ 7,502	$ 277	$ 451	(a)
4.56% Series	-	100,000	-	10,000	247	456	
4.60% Series	-	80,140	-	8,014	236	368	
4.64% Series	-	41,500	-	4,150	98	192	
6.08% Series	-	100,000	-	10,000	372	608	
Total	15,672	396,660	$ 1,567	$ 39,666	$ 1,230	$ 2,075	

(a) Noncallable.

The annual dividend requirement for total cumulative preferred stock was $94,000 and $2,075,000 at the end of 1998 and 1997, respectively. In 1998, the Company repurchased or redeemed preferred stock with an aggregate par value of $38 million.

Note J - Long-term Debt

A summary of long-term debt is as follows:

At December 31 (In thousands)

Series	Rate %	Maturity	1998	1997
General and Refunding (G&R) Mortgage Bonds:				
W(93-2)	6.17	February 2, 1998	$ -	$ 4,300
W(93-4)	6.14	February 2, 1998	-	1,300
W(93-5)	6.17	February 3, 1998	-	5,000
W(93-7)	6.10	February 4, 1998	-	10,000
W(93-9)	6.04	February 4, 1998	-	29,400
Y(94-4)	8.28	December 21, 1999	-	10,000
W(93-6)	6.58	February 10, 2000	-	5,000
Y(95-1)	7.94	February 14, 2000	-	5,000
Y(95-2)	7.93	February 14, 2000	-	10,000
Y(95-3)	7.40	March 21, 2000	-	10,000
Y(95-4)	6.69	June 5, 2000	-	25,000
W(93-1)	7.00	February 3, 2003	-	25,000
Y(94-2)	8.33	November 8, 2004	-	10,000
U	8.00	August 1, 2022	-	134,500
Y(94-1)	8.53	September 20, 2024	-	5,000
Pollution Control Revenue Bonds (a):				
K	7.25	October 15, 2015	-	38,500
MIFA 1 (b)	variable	March 1, 2018	**79,250**	79,250
BFA 1 (c)	variable	November 1, 2020	**135,850**	135,850
BFA 2 (c)	variable	November 1, 2020	**50,600**	50,600
MIFA 2 (b)	variable	October 1, 2022	**106,150**	106,150
Unamortized discounts			**(85)**	(2,130)
Total long-term debt			**371,765**	697,720
Long-term debt due in one year			-	(50,000)
			$ 371,765	$ 647,720

(a) Prior to September 1, 1998, the following debt was secured by G&R mortgage bonds.
(b) MIFA = Massachusetts Industrial Finance Authority
(c) BFA = Business Finance Authority of the State of New Hampshire

At December 31, 1998, interest rates on the Company's variable rate bonds ranged from 3.05 percent to 3.45 percent.

At December 31, 1998, the Company's long-term debt had a carrying value and fair value of $372,000,000. The fair value of debt that reprices frequently at market rates approximates carrying value.

In order to satisfy certain terms of its mortgage indenture, the Company defeased or retired all $641 million of its mortgage bonds outstanding at the time of the sale of its nonnuclear generating business. The Company retired $372 million of mortgage bonds securing the issuance of a like amount of pollution control revenue bonds (PCRBs), leaving the underlying PCRBs outstanding as unsecured obligations of the Company. Pursuant to a tender offer, the Company purchased $183 million of bonds. Provisions for the payment of the remaining mortgage bonds were made by depositing with trustees approximately $97 million of U.S. treasury obligations sufficient to pay principal, interest, and premium, as applicable, to the maturity date, or to the first date on which the bonds could be redeemed. Both the U.S. treasury obligations and defeased bonds were removed from the balance sheet effective September 30, 1998.

Note K - Common Stock

The Company repurchased shares of its common stock in 1998 as follows (dollar amounts expressed in thousands):

			Reductions to :		
Year	Number of Shares	Cash Paid	Common stock and related premium	Other paid-in capital	Retained earnings
1998	2,700,000	$417,960	$90,266	$133,876	$193,818

Note L - Supplementary Income Statement Information

Advertising expenses, expenditures for research and development, and rents were not material and there were no royalties paid in 1998, 1997, or 1996. Taxes, other than income taxes, charged to operating expenses are set forth by classes as follows:

Year ended December 31 (In thousands)	**1998**	1997	1996
Municipal property taxes	**$ 42,080**	$ 59,102	$ 58,942
Federal and state payroll and other taxes	**6,412**	8,209	7,474
	$ 48,492	$ 67,311	$ 66,416

New England Power Service Company, an affiliated service company operating pursuant to the provisions of Section 13 of the 1935 Act, furnished services to the Company at the cost of such services. These costs amounted to $74,203,000, $91,985,000, and $85,124,000, including capitalized construction costs of $21,281,000, $24,347,000, and $19,412,000, for each of the years 1998, 1997, and 1996, respectively.

Selected Financial Information

Year ended December 31 (In millions)	1998	1997	1996	1995	1994
Operating revenue	$ 1,218	$ 1,678	$ 1,600	$1,571	$ 1,541
Net income	$ 123	$ 145	$ 152	$ 151	$ 149
Total assets	$ 2,415	$ 2,763	$ 2,648	$2,648	$ 2,613
Capitalization:					
Common equity	$ 521	$ 913	$ 906	$ 889	$ 877
Cumulative preferred stock	1	40	40	61	61
Long-term debt	372	648	733	735	695
Total capitalization	$ 894	$ 1,601	$ 1,679	$1,685	$ 1,633
Preferred dividends declared	$ 1	$ 2	$ 3	$ 3	$ 3
Common dividends declared	$ 131	$ 135	$ 134	$ 135	$ 119

Selected Quarterly Financial Information (Unaudited)

(In thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
1998				
Operating revenue	$ 401,147	$ 358,320	$ 321,569	$ 137,304
Operating income	$ 48,740	$ 32,523	$ 54,647	$ 21,452
Net income	$ 35,950	$ 20,425	$ 47,956	$ 18,564
1997				
Operating revenue	$ 438,048	$ 396,049	$ 443,774	$ 400,032
Operating income	$ 50,652	$ 30,028	$ 64,535	$ 45,637
Net income	$ 37,945	$ 19,515	$ 52,019	$ 35,064

Per share data is not relevant because the Company's common stock is wholly owned by New England Electric System.

A copy of New England Power Company's Annual Report on Form 10-K to the Securities and Exchange Commission for the year ended December 31, 1998 will be available on or about April 1, 1999, upon request at no charge by contacting: Merrill IR Edge, 33 Boston Post Road, Suite 270, Marlborough, MA 01752, Telephone: 508-786-1907, Fax: 508-786-1915, E-mail: iredge@merrillcorp.com.