BOSTON EDISON
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, Massachusetts 02360

April 8, 1994

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10CFR140.15(b)(1)

2.94.038

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Docket 50-293

Annual Financial Statement

In accordance with 10CFR50.71(b) and 10CFR140.15(b)(1), Boston Edison is submitting the 1993 Annual Report and the Securities and Exchange Commission (SEC) Form 10-K which corresponds to the 1993 Annual Report.

BJ Hampton (for)

R. V. Fairbank
Manager - Regulatory Affairs
and Emergency Preparedness
Department

RVF/GGW/nas/ANFINRPT

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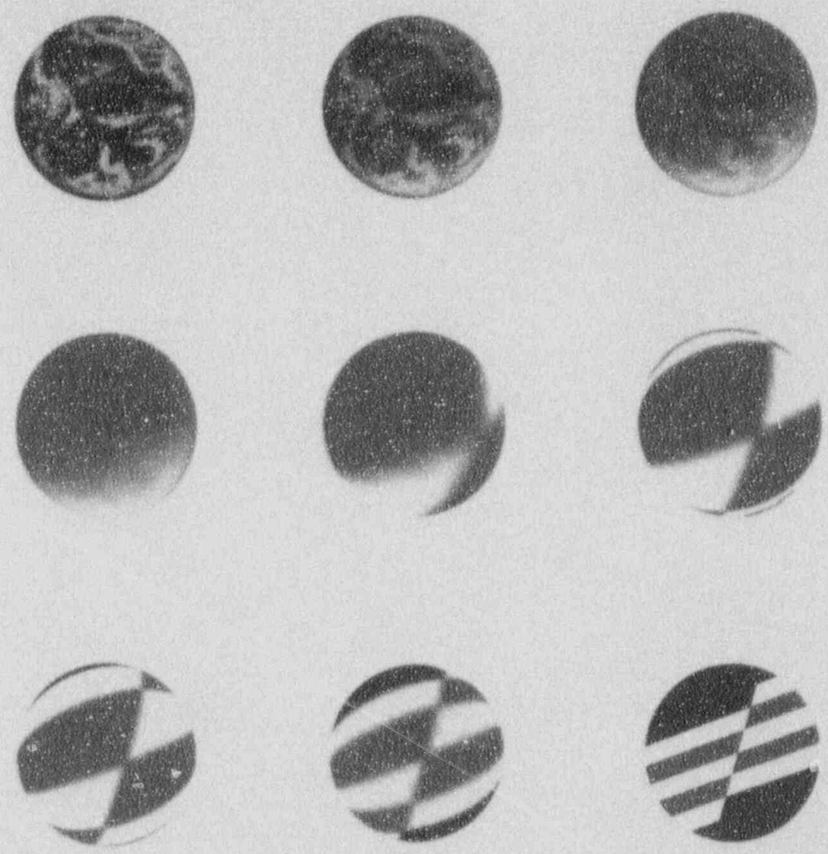
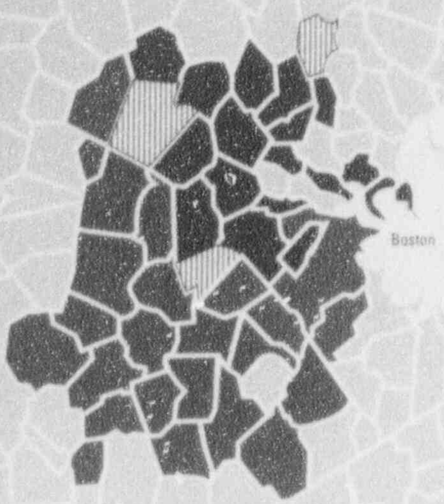


Boston Edison Company

1993 Annual Report



Serviced by Boston Edison:
- Northeast Area
- Central Area
- Southwest Area
- Wholesale customer

Financial Highlights:

	years ended December 31, 1993	1992	% change
Operating revenues (000)	**$1,482,253**	$1,411,753	+ 5.0%
Income available for common stock (000)	**$102,513**	$90,748	+13.0%
Common shares outstanding - weighted average (000)	**44,959**	43,144	+ 4.2%
Common stock data:			
Earnings per share	**$2.28**	$2.10	+ 8.6%
Dividends declared per share	**$1.715**	$1.655	+ 3.6%
Payout ratio	**75%**	78%	− 3.8%
Book value per share	**$19.42**	$18.77	+ 3.5%
Return on average common equity	**11.9%**	11.5%	+ 3.5%
Fixed charge coverage (SEC)	**2.27x**	1.93x	+17.6%

Certain reclassifications have been made to the data reported in the prior year to conform to the method of presentation used in 1993.

On the Cover:

Our New Corporate Identification

In recognition of our ever-increasing competitive environment, and the need to distinguish ourselves from the competition, we recently updated our corporate identification. This new identification evolves from our old signature, but changes enough to take us into the next century. The circle represents the earth and reflects our commitment to the environment, and streamlined service for customers. The lines form to communicate energy working in concert with the environment. You'll now see the new identification in all our communications with you.

Contents:

About the Company:

Boston Edison is a public utility engaged principally in the generation, purchase, transmission, distribution and sale of electric energy. It was incorporated in 1886. We supply electricity at retail to an area of approximately 590 square miles within 30 miles of Boston, encompassing the City of Boston and 39 surrounding cities and towns. The population of the territory served at retail is approximately 1,500,000.

We also supply electricity to other utilities and municipal electric departments at wholesale for resale. About 86 percent of our revenues are derived from retail electric sales, 12 percent from wholesale sales and 2 percent from other sources.

Dear Shareholder:

Nineteen ninety-three was an excellent year for Boston Edison shareholders. For the fifth consecutive year, our management team and employees worked together to provide total returns that beat both market and industry averages. In fact, the total return on your investment, including dividends paid, was 14.5 percent. Earnings were also good in 1993, rising 8.6 percent, to $2.28 per share. And, the Board of Directors again increased your dividend by 6 cents, or 3.5 percent.

Our positive performance was the result of our commitment to controlling costs and continued operational excellence. To control costs in 1993, we completed several refinancings, which dramatically altered the make-up of our debt and some of our preferred stock, resulting in annual savings of more than $11 million in interest and dividend costs. We also continued to reduce the number of employees in our workforce resulting in a decrease from 4,540 in 1992 to 4,404 in 1993, a reduction of 136 positions. Since 1991, our workforce has been reduced mainly through attrition by close to 400 positions, or nine percent.

Operationally in 1993, Pilgrim Nuclear Power Station completed its shortest refueling outage ever at 57 days, and earned its best "report card" from the Nuclear Regulatory Commission. Three of our fossil units completed major overhauls on time and within budget, preparing us for strong unit performance and reliable power for customers for many years to come.

Our focus on competition intensified in 1993 as evidenced by our strategic plan. Its details emphasize reduced costs and improved service to both wholesale and retail customers, more efficient and effective technology and new energy-related businesses, while recognizing the need to continue providing investors with steady financial growth that outperforms the industry.

Our financial condition will improve from recent victories in the wholesale customer market. In 1993, we signed agreements with two existing wholesale customers and added a new customer to our list: the Town of Braintree. We have now successfully negotiated contracts to supply power to five wholesale customers until at least the year 2002.

For our retail customers, we seek to provide price stability. To that end, we have set an aggressive goal to not seek any additional base rate increases, beyond what is already approved, through the year 2000. Our managers are therefore challenged to continue providing financial growth for shareholders, while holding prices steady for customers. This can only be accomplished by simultaneously increasing revenues and reducing the costs of doing business.

Increasing sales is largely dependent upon the strength of our local economy. Therefore, we have assumed a leadership role in helping our cities and our state create jobs, and we are lending our material and human resources to build solid and safe communities. Recent reports indicate some success as local unemployment figures fell below the national average, office vacancies decreased, consumer confidence improved, and home starts and sales have begun to rise. Given these positive indicators, we have revised our forecasts for improved sales growth to 1.5 percent.

We will also improve revenue growth by actively marketing new electric technologies, products, and services to our customers to improve their operations and help the environment. By combining new electric technologies with demand-side management programs, we will offer customers a total value package of energy options and services to run their homes and businesses, and create additional revenues for Boston Edison.

To help control costs, we will continue to seek out and invest in technologies that enable us to work more efficiently and effectively. To that end, we have established a new technology research and development function which will evaluate and integrate new technologies into our operations to lower costs and enhance customer service.

Finally, we have a strategy to pursue electricity-related business opportunities through our first unregulated subsidiary, the Boston Energy Technology Group. We will invest up to $45 million over three years in new businesses, including an electric vehicle recharging distributorship. Our latest new business acquisition, REZ-TEK International Corp., is a company which has developed an innovative system that treats cooling water used in commercial and industrial air conditioning systems in an energy efficient and environmentally sound manner that eliminates chemical treatment.

None of what we have discussed is achievable without focusing on the human side of our enterprise. Employees have been responsible for our success to date, and will be key to creating our future. They are responsible for continuing to improve internal operations and offering products and services to increase value to our customers.

Our 1993 performance is evidence of our strength and conviction to succeed. We are in control of our business, and by continuously improving all aspects of our operations, we are creating our future.

Bernie Reznicek　　　　Tom May

Bernard W. Reznicek
Chairman and
Chief Executive Officer

Thomas J. May
President and
Chief Operating Officer

February 17, 1994

The inset (top) is a model of our new Energy Management Center, scheduled to open in 1994. This center will incorporate a new interactive computer mapping system (pictured in background), using remote terminal phone line technology to provide more accurate, on-line information on system performance. The facility will give employees the ability to control the delivery of electricity from our generating stations to our customers' homes.

President and Chief Operating Officer, Tom May

Chairman and Chief Executive Officer, Bernie Reznicek

To retain and expand our customer base, we must deliver value in the form of energy efficient and environmentally beneficial products and quality services to help customers run their homes and businesses.

Customer Sales, Service and Marketing

Customers demand excellent service, and look for "one stop" shopping. To accomplish this, we've restructured and refocused our sales and service organizations, and elevated standards for performance. We're creating a customer-driven, profit-enhancing marketing plan, building the skills and competencies of our marketing and sales forces, and, most importantly, reengineering service delivery processes for our customers.

Wanda Vasquez is a customer service representative who helps customers with billing questions, service issues, and applications for new electric service.

We're developing a better understanding of our customer market segments so that we may become energy consultants for each group. This understanding will improve our ability to provide customers with a variety of demand side management programs, as well as quality services and efficient electric technologies which meet their needs and expectations.

Some of the new, energy efficient technologies and environmentally beneficial products we're offering include electric chillers which provide efficient, reliable cooling for large commercial facilities. For the variety of medical customers in our territory, electric disinfection and volume reduction systems offer a cost-effective, environmentally sound way to treat and dispose of hazardous medical wastes. We're also working with residential customers to offer advanced heating and cooling systems for significant cost savings.

We've reallocated our customer representatives' time to help us accomplish our goal. The result: front-line sales and service employees will spend more time in the field, working one-on-one with customers, with the full support of an in-house technical and administrative team. These representatives will provide customers value through a variety of services, including real-time information on customers' energy usage and patterns accessed through lap-top computers and remote data links to corporate headquarters.

Tom Puddister is one of a team of auto mechanics who maintains our fleet of electric cars and vans.

A system called CADIMAGE will provide us with valuable computer graphics, database mapping, and facilities management needed in our daily field operations.

We are also adding services that allow us to use our technical knowledge to meet customers' internal operating needs, thus expanding our role to provide customer services on the other side of the meter.

While many of our efforts are targeted to existing customers, we'll continue to pursue new ones aggressively, especially in the wholesale market. We are currently preparing a number of active bids for new wholesale customers which include value-added programs and services that should help set us apart from the competition.

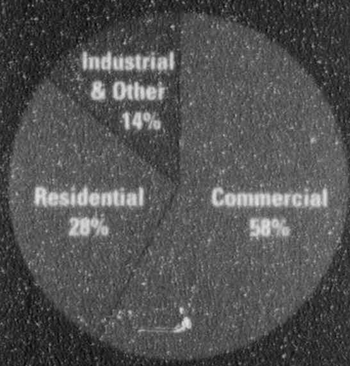
Customers expect Boston Edison to be a good corporate citizen, and to take our role in the community seriously. In addition to corporate giving, education, and environmental protection programs, we fulfill our corporate responsibility by helping to bring jobs to Massachusetts.

Our 1993 efforts garnered solid results: our economic development rate, which provides 4-year rate discounts to eligible customers, helped attract seven new manufacturing firms and more than $1 million in annual base revenues for Boston Edison. In addition, we've been instrumental in developing and implementing a program in which local CEOs promote Massachusetts to CEOs around the country, in order to attract business to the state.

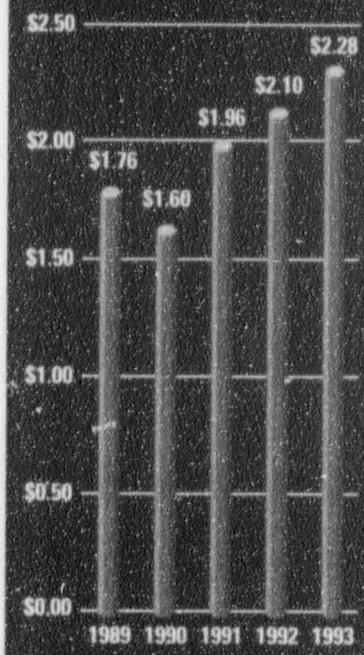
Finally, we'll continue to support the electric vehicle and electric mass transit markets through infrastructure development, coordination with fleet managers to encourage the purchase of electric vehicles, support of legislation, use of electric vehicles in our fleet, demonstrations at area schools, and loaning vehicles to media and opinion leaders. Expansion of the electric transportation market is good news for the environment, and for revenue growth.

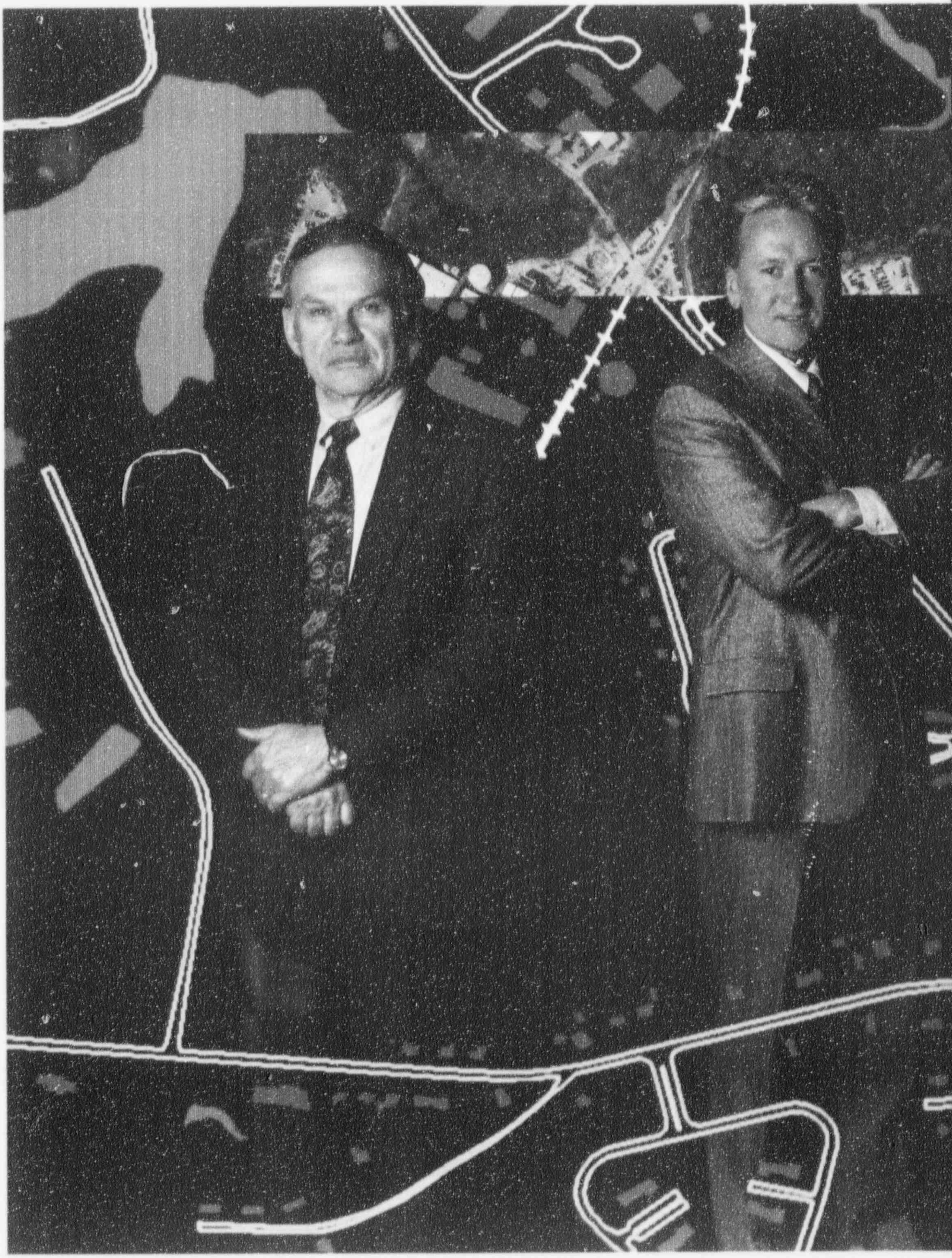
Our success will be measured by stronger customer relationships, greater employee opportunities, a larger customer base, and increased revenues and profits.

Our RETAIL CUSTOMER MIX is stabilized by the commercial and residential sectors which help minimize effects of regional economic swings.



EARNINGS PER SHARE FROM OPERATIONS rose 8.6% in 1993.





VALUE-ADDED SERVICES

CADIMAGE is a computer graphic and database application technology that replaces manual paper maps and diagrams of the facilities, lines and stations throughout our service territory with on-line, computerized files.

CADIMAGE's original purpose was as an internal tool for improving employee efficiency through better information. We are also exploring a partnership with the Town of Arlington to investigate how CADIMAGE may provide communities with value-added services. CADIMAGE may have applications in servicing municipal needs such as planning, assessing, engineering, and public safety.

Left to right are Arlington Town Manager, Don Marquis; CADIMAGE Development Coordinator, Dick Cohane; and Executive Vice President, George Davis.

Customer satisfaction depends, in large part, on the price and reliability of our product. To provide a reliable, competitively priced product we must control costs, manage our business well, and invest in technologies that improve efficiencies and reduce costs.

Cost Control & Operational Excellence

Stable, predictable prices are important to customers. So, we've recently announced a goal to avoid requesting base price increases, beyond what is already approved, through the year 2000.

To accomplish the goal, we must continue our efforts to control costs. We must continue to make full use of employees' skills and available technology. Thanks to improved employee efficiency and better use of technology, we've been able to reduce our workforce, primarily through attrition. We'll continue to reduce our total number of employees based on further technological advances and restructurings for improved efficiency.

Ed Foley is a fossil station mechanic who provides maintenance for all major plant equipment at our New Boston power plant to ensure its safe, reliable, and efficient operation.

Management and union leaders have worked well together to improve performance and reduce costs. For example, in 1993, we worked with our union-represented employees and their leadership to combine 14 specific service job descriptions into just four classifications. These employees are now being trained, and will be responsible for handling a wider variety of field work for improved customer service at a lower cost.

Al Abramson is a splicer in our electric customer service area who maintains and repairs the underground cables that provide power to our customers.

Pursuing technological advances in metering can also help us save money through faster payment of customer bills, lower labor costs per meter read, and avoidance of safety and access problems for our meter readers. In 1994, we'll invest nearly $7 million in equipment that reads, disconnects, and reconnects meters remotely.

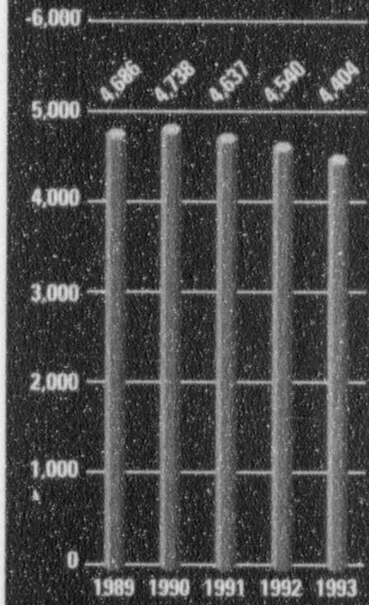
We'll control costs by better managing our inventories. In 1993, we reduced inventory by $13 million, and in 1994, we'll work with our vendors to incorporate a "just-in-time" inventory philosophy for further savings and efficiencies.

Effective maintenance of our plants and systems is necessary for success. In 1994 and beyond, we'll benefit from 1993's preventive maintenance overhauls of half our fossil units. In fact, this increased focus on maintenance has permitted us to extend our fossil unit overhaul cycles from five to six years, and refueling intervals at Pilgrim Station to every two years. This will help us to exceed the on-line capacity range of 60 - 68% set by our state regulators for Pilgrim Station.

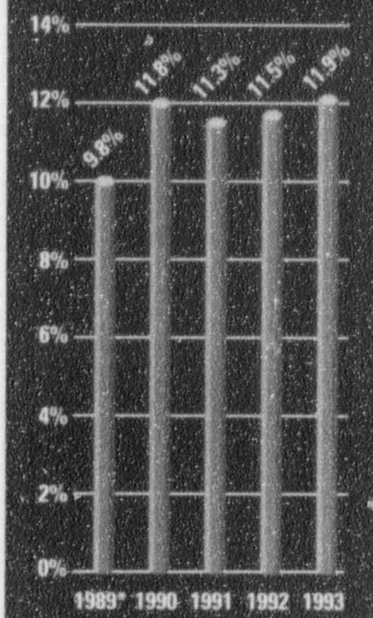
To control maintenance and equipment costs, we'll use computerized models and available technologies such as vibration monitoring to identify problems before they become severe. The result: minimum unit down-time, and reductions in rush orders and high cost replacement equipment.

Critical to our goals of cost control and continuous improvement will be the ongoing involvement of our managers. These employees will run their departments as small business units. To help our managers monitor performance against the competition in areas such as employee productivity, customer

TOTAL NUMBER OF EMPLOYEES decreased 3% in 1993 through attrition, in line with our plans to pare down by about 100 employees annually through the year 2000.



RETURN ON EQUITY in 1993 increased for the second year, coming in close to 12%.

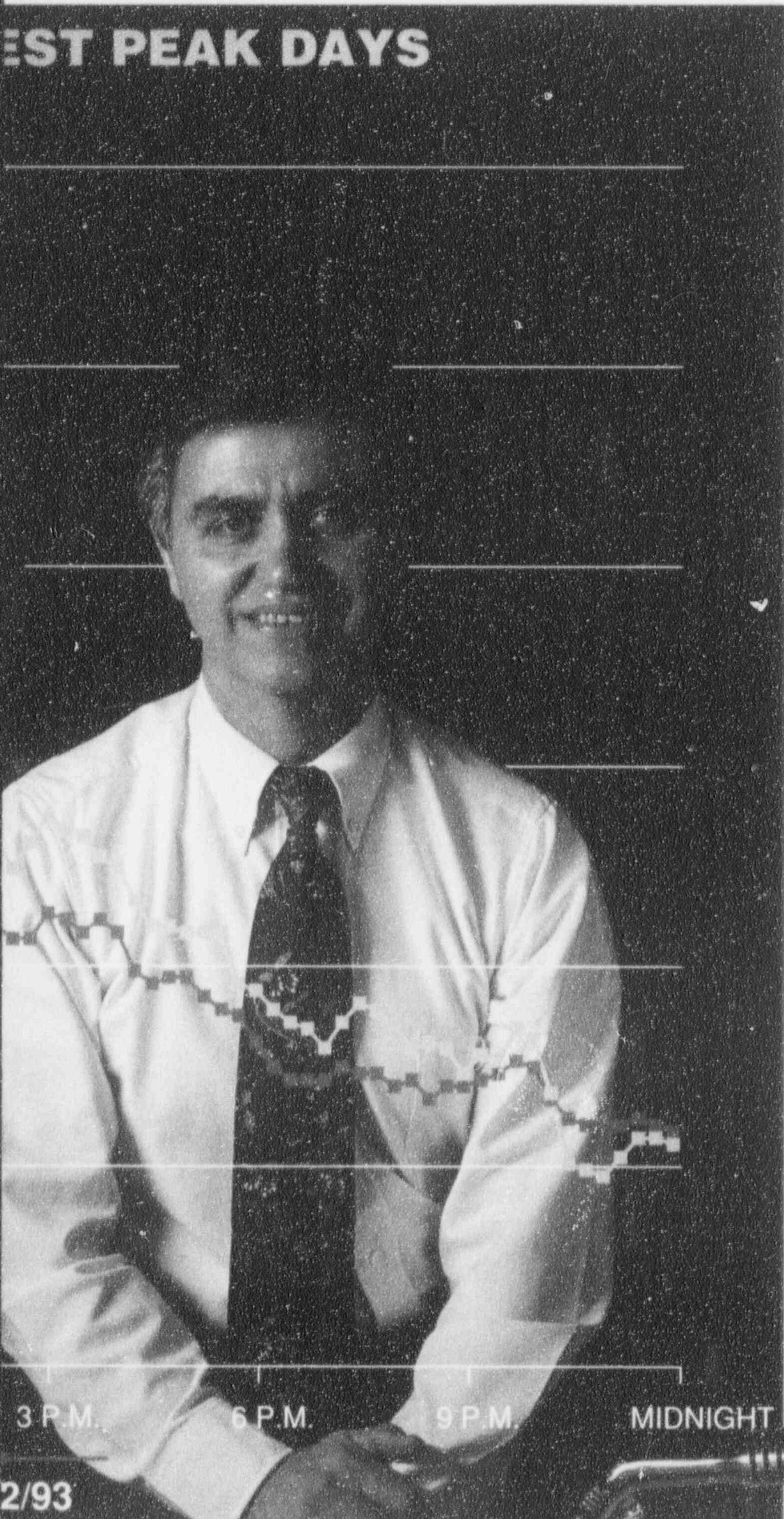


* Adjusted for one-time write-off.

service, and environmental performance, the company will use benchmarking tools.

Looking outside the company, we'll continue our work with state officials and regulators on rules which affect the methods we use and the costs we incur to meet customers' power demands. Our state regulators have created an integrated resource management (IRM) process in which electric utilities forecast future energy needs and propose how they will meet them by balancing conservation programs and all other available supply options. We're working closely with regulators to ensure the IRM process results in meeting customer demand for power at the lowest possible cost.


FIRST AND SECOND HIG
Demand (KW)
11000
10000
6000
5000
MIDNIGHT
3 A.M.
6 A.M.
9 A.M.
NOON
12/21/93



FIELD-BASED ENERGY CONSULTING

LOADMAP is a software application developed by our employees to help customers manage their energy usage and costs. LOADMAP provides computerized spreadsheets of monthly energy, demand, and efficiency statistics.

LOADMAP and other software programs are offered by our customer sales representatives to nearly 200 commercial and industrial customers as important field-based energy consulting tools. For instance, The Gillette Company's South Boston manufacturing center uses LOADMAP to help them analyze their power consumption and the impact their production operations have on energy usage and costs.

Left to right are Major Account Representative, Tom Horan; Vice President of Sales and Service, Alison Alden; and The Gillette Company's Manager of Power and Utilities, Bill Bushey.

Employee involvement is crucial for Boston Edison's success in a competitive environment. Our employees serve customers, implement corporate strategies, run our business, and identify ideas for improvement. Our employees understand the competitive nature of our business, the importance of cost control, and the need to provide excellent service and value to our customers. We must continue to provide employees with the tools, information, involvement, and management necessary for success.

Employee Effectiveness and Involvement

As the largest single shareholder group, holding nearly 2 million shares, Boston Edison employees are personally and professionally invested in our company's success. In addition, more than 40% of our employees are also our customers, since they live within our service territory.

Rosa Menard is a career development specialist who manages our job rotation program for employees.

Employees have been instrumental in all aspects of our evolution to a strong competitive company. Design teams of employees have shaped reorganizations of our workforce to ensure we have the right processes, procedures, organizations and people to meet customers' demands.

These teams have analyzed the work we do, the value of the work to the customer, the processes involved, and the existing staffing levels. They identified low value work that should be eliminated, process improvements for greater efficiencies, and appropriate staffing levels for these new functions.

And long after the design teams have done their job, we'll continue to keep employees involved in making it easy for customers to do business with us. One employee team, called the Key Account Group, is currently defining how we'll work with our major customers. Another team, called the Customer Support Group, is reengineering the services we provide to medium and large sized customers.

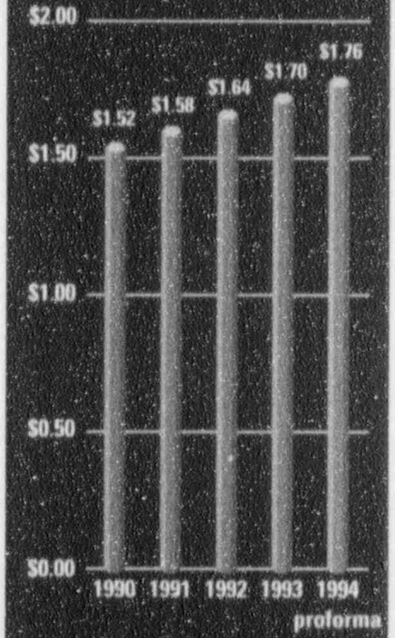
Jean Dickson is a facilitator who leads employee teams in re-designing work processes and organizational structure.

Another team is identifying process and technology improvements to streamline new customer work orders. These improvements will reduce the cost of providing new services, while offering better customer service.

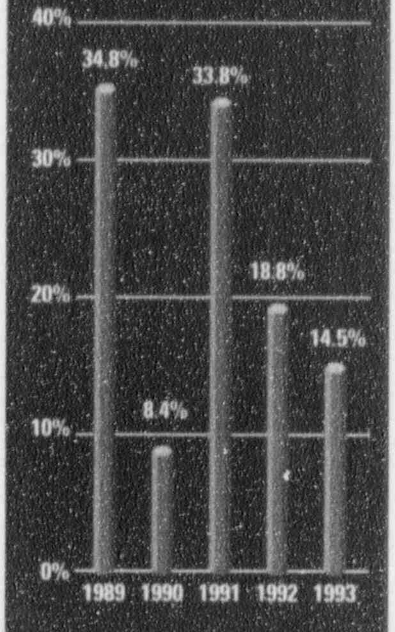
Employees are committed to fully understanding our new business environment, so that they may respond to it effectively. A series of competitive business issue videos and fact sheets have been produced, a standing-room-only series of utility finance classes were introduced, and our popular lunchtime lecture series has been refocused to emphasize the new challenges we face in trying to keep and attract customers.

Employees are also learning valuable new perspectives through a new company initiative. By participating in job rotations in 1993, several employees moved to new areas, managed new projects and people, and learned new skills important to our success.

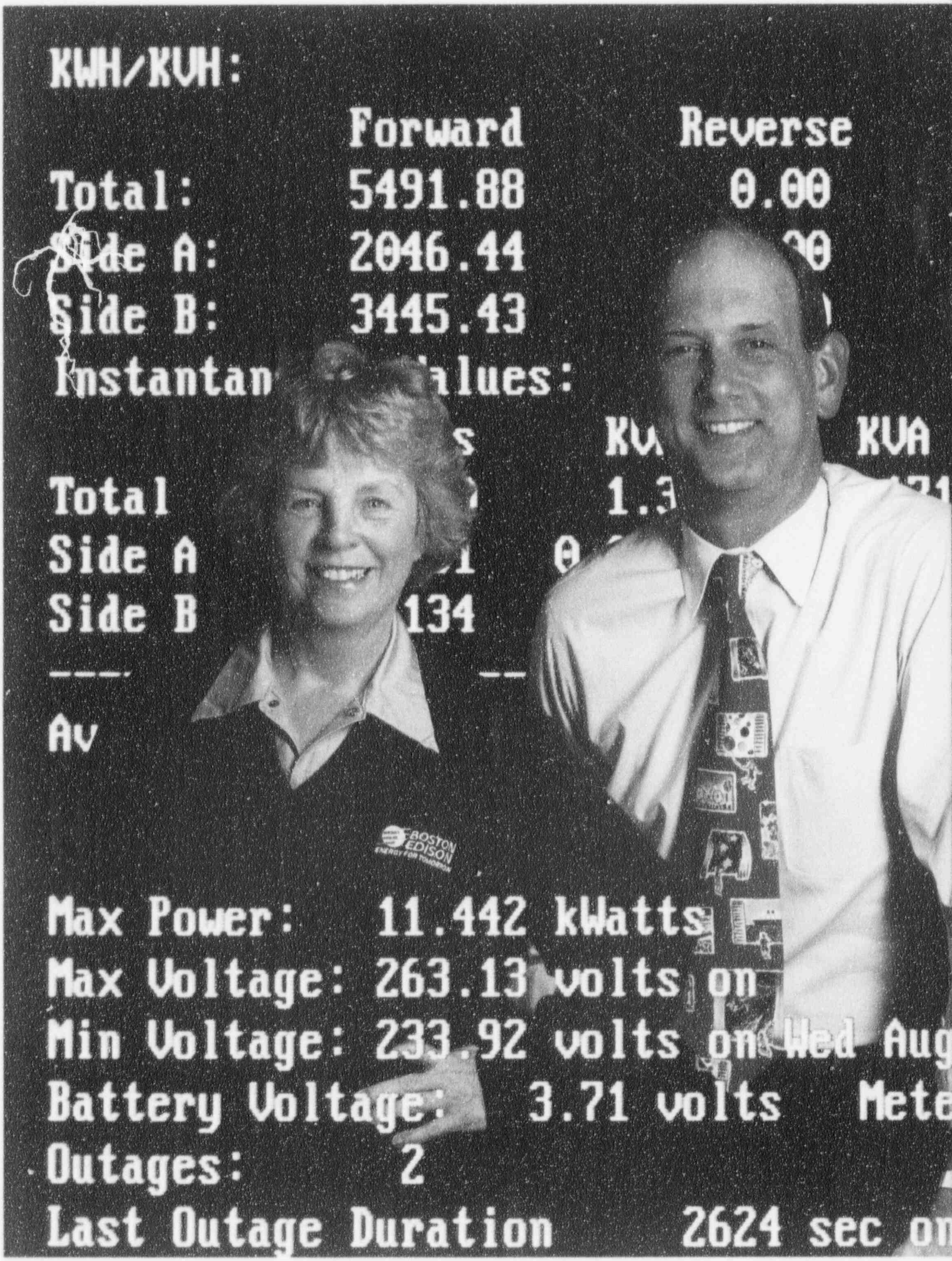
DIVIDENDS PAID PER SHARE increased on a percentage basis by more than the industry average in each of the last four years.

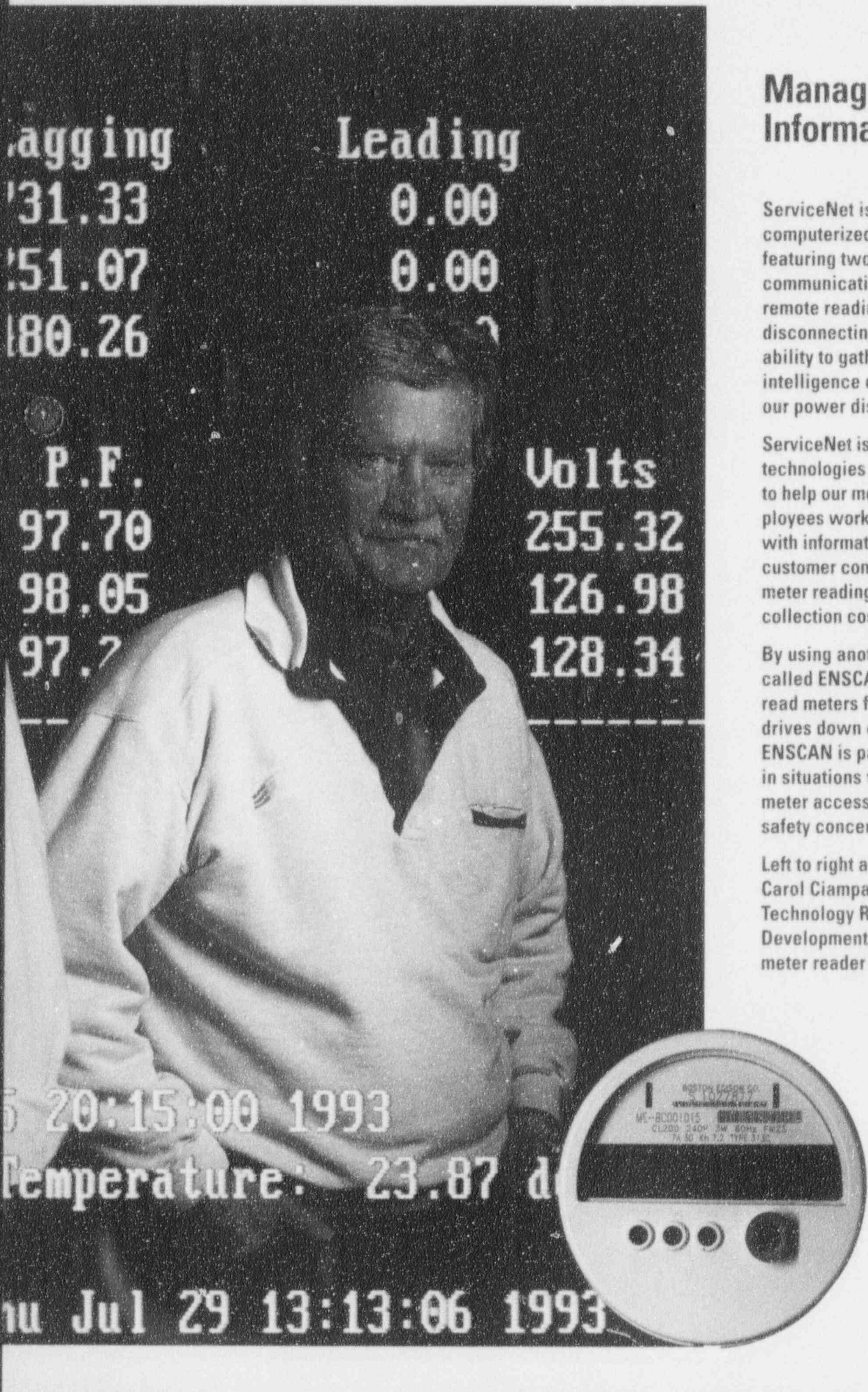


ANNUAL TOTAL RETURN TO SHAREHOLDERS has exceeded industry and market averages for the past five years.



Looking ahead, our managers are better able to see into the future and plan strategically, thanks to a new tool called the workforce planning model. This computerized technique will help managers forecast staffing requirements by analyzing variables such as attrition rates and productivity figures.


KWH/KVH:
Forward
Reverse
Total:
5491.88
0.00
Side A:
2046.44
Side B:
3445.43
KVA
Total
Side A
Side B
Max Power: 11.442 kWatts
Max Voltage: 263.13 volts on
Min Voltage: 233.92 volts on Wed Aug
Battery Voltage: 3.71 volts
Outages: 2
Last Outage Duration 2624 sec
BOSTON EDISON
ENERGY FOR TOMORROW



Managing with Information

ServiceNet is an integrated, computerized technology featuring two-way radio communications that allows for remote reading, connecting and disconnecting of meters, and the ability to gather real-time intelligence on the operation of our power distribution systems.

ServiceNet is one of several new technologies we've incorporated to help our meter reading employees work efficiently, manage with information, reduce customer complaints, and lower meter reading, billing, and collection costs.

By using another technology called ENSCAN, employees can read meters from a van as it drives down customers' streets. ENSCAN is particularly helpful in situations where there are meter access or employee safety concerns.

Left to right are meter reader Carol Ciampa; Vice President of Technology Research and Development, Dick Hahn; and meter reader Mike Joyce.

Regulatory Proceedings

Retail settlement agreements

Effective November 1992 our state regulators, the Massachusetts Department of Public Utilities, approved a three-year settlement agreement. This agreement provides us with retail rate increases, allows for the recovery of demand side management (DSM) conservation program expenditures, specifies certain accounting adjustments and clarifies the timing and recognition of certain expenses. The agreement also sets a limit on our rate of return on common equity of 11.75% for 1993 through 1995, excluding any penalties or rewards from performance incentives.

The retail rate increases consist of a new annual performance adjustment charge effective November 1992 and two additional rate increases of $29 million effective November 1993 and November 1994. The performance adjustment charge varies annually based upon the performance of our Pilgrim Nuclear Power Station. This charge is further described in our discussion of financial condition.

Our 1993 results of operations were affected by the recovery of DSM program expenditures, accounting adjustments and timing and recognition of certain expenses as further described in the following Results of Operations section.

Our state regulators approved a previous three-year settlement agreement effective November 1989. That agreement also provided us with retail rate increases and specified certain accounti ng adjustments. The 1989 agreement primarily affected our results of operations through 1992.

Results of Operations

1993 Versus 1992

Earnings per common share were $2.28 in 1993 and $2.10 in 1992. The increase in earnings is primarily the result of an annual rate increase effective November 1992, lower purchased power expense due to a long-term contract expiration, no amortization of deferred cancelled nuclear unit costs and lower interest expense. These positive changes were partially offset by higher operations and maintenance expense and higher income tax and property tax expenses.

Operating revenues

Operating revenues increased 5% over 1992 as follows:

(in thousands)	
Retail electric revenues	$70,837
Demand side management revenues	33,601
Wholesale and other revenues	(2,794)
Short-term sales revenues	(31,144)
Increase in operating revenues	$70,500

Retail electric revenues increased $70.8 million. The November 1992 and 1993 rate increases resulted in $40.6 million of additional revenues in 1993. Fuel and purchased power revenues increased $29.5 million over 1992, partly due to lower revenue: received from short-term power sales as discussed below.

We began recovery of certain demand side management program costs, lost base revenues and incentives in August 1992. Our 1993 revenues provided $45.9 million related to 1991, 1992 and 1993 DSM programs. Our 1992 revenues of $12.3 million related primarily to 1991 programs.

The decrease in wholesale and other revenues reflects an estimated provision for refunds to customers of approximately $8 million as a result of orders from our state regulators on our generating unit performance program.

Lower short-term power sales revenues were a result of changes in our generation availability and the needs of short-term power purchasers. All revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and have no effect on earnings.

Operating expenses

Fuel expense decreased $19.5 million primarily due to a 21.5% decrease in generation, resulting from planned overhauls of our fossil plants. Interchange purchases increased due to the lower generation, resulting in a $7.5 million net increase in purchased power expense. The net increase also reflects savings of approximately $10 million from a long-term purchased power contract that expired in October 1993. Both our fuel and purchased power expenses are substantially fully recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 7.1% primarily due to increases in employee benefits and nuclear production expenses. Postretirement benefits expense increased by $7 million primarily as a result of the adoption of a new accounting standard and pension expense increased by $5 million; both are provided for in our 1992 settlement agreement and further explained in Note I to the consolidated financial statements. A refueling outage at Pilgrim Station in 1993 resulted in higher nuclear production expenses.

Depreciation and amortization expense increased in 1993 primarily due to a higher annual decommissioning charge for Pilgrim Station effective November 1992 provided by the 1992 settlement agreement. The new charge is based on a 1991 estimate of decommissioning costs as further discussed in Note D to the consolidated financial statements. In addition, the effect of lower depreciation rates implemented in accordance with the settlement agreement was offset by the effect of a higher depreciable plant balance.

In accordance with our 1992 settlement agreement we did not expense any of the $19 million of remaining deferred costs associated with the cancelled Pilgrim 2 nuclear unit in 1993. We will expense the remaining costs in 1994 and/or 1995.

Amortization of deferred nuclear outage costs includes amounts related to the 1993 and 1991 refueling outages at Pilgrim Station. In 1993 we deferred approximately $14 million of refueling outage costs. We began to amortize these costs in June 1993 over five years as approved in the 1992 settlement agreement.

The increase in demand side management programs expense is consistent with the increase in DSM revenues. DSM expense includes some costs recovered over a twelve month period and other costs recovered over six years. We began to recover previously deferred DSM expenses in August 1992. In 1993 we expensed and collected from customers approximately $30 million of deferred 1991, 1992 and 1993 program costs. Over six years we are expensing and collecting from our customers $11 million of costs capitalized in 1992 and $37 million of costs capitalized in 1993. The 1993 expense related to these capitalized costs was $7 million.

Municipal property and other taxes increased in 1993 due to the absence of tax abatements. In 1992 property taxes were reduced by $10.4 million of tax abatements in accordance with our 1989 settlement agreement.

Our effective annual income tax rate for 1993 was 23.4% vs. 8.7% for 1992. Both rates were significantly reduced by adjustments to deferred income taxes of $20 million in 1993 and $23 million in 1992 made in accordance with the 1992 and 1989 settlement agreements. The 1992 rate was also reduced due to tax benefits of approximately $7 million resulting from mandated payments made in accordance with the 1989 agreement. Our adoption of a new accounting standard for income taxes in 1993 did not significantly affect earnings. We expect our effective tax rate to be close to the statutory rate in 1994.

Interest charges and preferred and preference dividends

Total interest charges decreased $3.8 million in 1993. Interest on long-term debt decreased primarily due to the refinancing of substantially all our first mortgage bonds in 1993 at lower interest rates, partially offset by higher amortization of redemption premiums. Other interest charges decreased due to a lower short-term debt level and lower short-term interest rates. Allowance for funds used during construction (AFUDC), which represents the financing costs of construction, decreased as a result of a lower AFUDC rate related to lower short-term interest rates.

Preferred and preference dividends decreased 5% due to the replacement of a preferred and a preference stock issue with less costly issues of preferred stock.

1992 Versus 1991

Earnings per common share were $2.10 in 1992 and $1.96 in 1991. The increase in earnings is primarily the result of a rate increase effective November 1991, incentive revenues earned from the performance of Pilgrim Station and lower income tax and interest expenses. These increases were partially offset by higher operations and maintenance and property tax expenses. We also had a one-time charge in 1992 for costs incurred for a deferred generating plant project.

Operating revenues

Operating revenues increased 4.2% over 1991 as follows:

(in thousands)

Retail electric revenues	$27,672
Demand side management revenues	12,343
Wholesale and other revenues	1,881
Short-term sales revenues	15,356
Increase in operating revenues	$57,252

Retail electric revenues increased $27.7 million. We received a $25 million rate increase effective November 1991 as part of the 1989 settlement agreement. We also earned $8.2 million in incentive revenues in 1992 as a result of Pilgrim Station's capacity factor exceeding its target set in the agreement. Fuel and purchased power revenues decreased approximately $5 million due to higher purchased power costs more than offset by higher revenues received from short-term power sales as discussed below.

In 1992 we began to receive revenues for the recovery of certain DSM program costs, lost base revenues and incentives. The 1992 revenues relate primarily to 1991 DSM programs.

Our short-term power sales increased in 1992 as a result of our high generating unit availability and the greater power needs of other New England utilities. All revenues from short-term sales served to reduce fuel and purchased power billings to retail customers and had no effect on earnings.

Operating expenses

Purchased power expense increased $18 million in 1992 due to new long-term purchased power contracts. Both our fuel and purchased power expenses are substantially fully recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 2.3% due primarily to increases in employee benefit expenses and bad debts.

Amortization of deferred nuclear outage costs in 1992 and 1991 includes amounts primarily related to the 1991 refueling outage at Pilgrim Station. In 1991 we deferred approximately $23 million of refueling outage costs. We began to expense these costs over five years in September 1991 as approved by our state regulators.

Municipal property and other taxes increased 21% primarily due to a reduction in residential and commercial real estate values caused by the depressed economy. This resulted in higher tax rates applied to our personal property values. In accordance with our 1989 settlement agreement, municipal property tax expenses were reduced by tax abatements of $10.4 million in 1992 and $13.6 million in 1991.

Our effective annual income tax rate for 1992 was 8.7% vs. 16.5% for 1991. Both rates were significantly reduced by adjustments to deferred income taxes of $23 million in 1992 and $13 million in 1991 made in accordance with the 1989 settlement agreement. We also received tax benefits in both years as a result of payments mandated by the agreement.

Other income and expense

In 1992 we expensed $8 million of costs previously invested in the proposed Edgar Energy Park generation project. This project was deferred indefinitely as additional generating capacity is not expected to be needed for several years.

Interest charges and preferred and preference dividends

Total interest charges decreased 4.6% primarily due to lower interest rates on our average short-term borrowings. AFUDC decreased 12.7% due to a lower AFUDC rate related to lower short-term interest rates.

Preferred and preference dividends decreased approximately $1 million primarily due to the replacement of two preference stock series with less costly issues of preferred stock.

Earnings per share

Net income increased 13%. However, earnings per common share for 1992 increased only 7%, reflecting an increase in the weighted average number of common shares outstanding primarily a result of our 1991 and 1992 common stock issuances.

Financial Condition

Our 1992 settlement agreement provides us with increased revenues from retail customers over the three-year period ending October 1995. Additionally, a long-term purchased power contract with annual charges of approximately $60 million expired in October 1993 with no related change in revenues. We are limited to an annual rate of return on equity during the three-year period of 11.75%, excluding any penalties or rewards from performance incentives.

Our continued ability to achieve or exceed the 11.75% rate of return on equity will be primarily dependent upon our ability to control costs and to earn performance incentives from generation performance mechanisms specified in both the 1989 and 1992 settlement agreements. The most significant impact that incentives can have on our financial results is based on Pilgrim Station's annual capacity factor. Effective November 1993 an annual capacity factor between 60% and 68% will provide us with approximately $45 million of revenues through the performance adjustment charge. For each percentage point increase in capacity factor above 68%, annual revenues will increase by $670,000. For each percentage point decrease in capacity factor below 60% (to a minimum of 35%) annual revenues will decrease by $770,000. Pilgrim's capacity factor for the performance year ending October 1994 is expected to be approximately 81% (assuming normal operating conditions), an increase over the 66% capacity factor achieved in the performance year ended October 1993, as no refueling outage is scheduled for 1994. We earned approximately $40 million in performance charge revenues in the performance year ended October 1993.

Our fossil generation unit performance can provide an increase or decrease of up to $4 million in revenues in each performance year, however, we do not expect any revenue adjustments from this mechanism.

Liquidity

We meet our plant expenditure cash requirements primarily with internally generated funds. These funds (excluding payments made related to settlement agreements) provided for 74%, 90% and 89% of our plant expenditures in 1993, 1992 and 1991, respectively. Our current estimate of plant expenditures for 1994 is $233 million, including $20 million of nuclear fuel additions. These expenditures will be used primarily to maintain and improve existing transmission, distribution and generation facilities. We also estimate capitalizable DSM expenditures to be $38 million in 1994, which will be collected from customers over six years. We do not expect plant expenditures, excluding nuclear fuel and DSM, to vary significantly from the 1994 amount in the four years thereafter. We have long-term debt and preferred stock payment requirements of $2 million in 1994, $102.6 million in 1995, and $103.6 million per year in 1996 through 1998.

External financings continue to be necessary to supplement our internally generated funds, primarily the issuance of short-term commercial paper and bank borrowings. We currently have authority from our federal regulators to issue up to $350 million of short-term debt. We have a $200 million revolving credit agreement and arrangements with several banks to provide additional short-term credit on a committed as well as on an uncommitted and as available basis. At December 31, 1993 we had $204.1 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. In 1993 our state regulators approved a financing plan allowing us to issue up to $1.1 billion in securities through 1994 and to use the proceeds to refinance long-term securities and short-term debt. At December 31, 1993 we had $245 million remaining authorized to be issued under the plan which can be used to issue common stock, preferred stock and long-term debt. As a result of our refinancing activities in 1993 we expect to realize annualized savings of approximately $11.5 million. Refer to Note F to the consolidated financial statements for specific information relating to our recent financing activities.

Outlook for the Future

Electricity sales

A significant portion of our electricity sales is made to commercial customers rather than industrial customers. As a result our sales have been only moderately impacted by the decline in the local Massachusetts economy. Our retail sales increased 1.2% in 1993 and we anticipate only slight growth in retail sales in the near term.

Implementation of DSM programs, which are designed to assist customers in reducing electricity use, will result in lower growth in electricity sales. The 1992 settlement agreement established annual DSM spending levels over $50 million through 1994. The agreement provides for collection from customers of certain costs primarily in the year incurred and others over a six-year period. We are also provided with incentives and recovery of lost revenues based on the actual reduction in customer electricity usage from these programs and a return on the costs that we recover over six years.

Competition

As we are operating in a time of increasing competition from other electric utilities and non-utility generators to sell electricity for resale, we have secured long-term power supply agreements with our four wholesale customers. Through these agreements our rates are set principally through the year 2002. We also obtained a new wholesale customer in 1993 for which we will provide up to 30 megawatts of contract demand power for ten years beginning November 1994.

Our state regulators require utilities to purchase power from qualifying non-utility generators at prices set through a bidding process. In June 1993 our state regulators ordered us to purchase 132 megawatts of power from an independent power producer, starting as early as 1995. We oppose this order since we do not believe we need any new power for several years. In July 1993 we asked the Massachusetts Supreme Judicial Court to reverse the order. We are currently awaiting a decision from the court. In addition, our state regulators have created an integrated resource management (IRM) process in which electric utilities forecast their future energy needs and propose how they will meet those needs by balancing conservation programs with all other supplies of energy. We will submit an IRM filing in March 1994.

Direct competition with other electric utilities for retail electricity sales is still subject to substantial limitations, but these limitations may be reduced in the future. In 1993 we announced our goal of not seeking additional rate increases, other than those provided in the 1992 settlement agreement, for our residential, commercial and industrial customers until at least the year 2000. We plan to accomplish this by controlling costs and increasing operating efficiencies without sacrificing quality of service or profitability. The announcement reflects our strong commitment to be a competitively priced reliable provider of energy.

Non-utility business

In 1993 we created an unregulated subsidiary known as the Boston Energy Technology Group (BETG) following approval from our state regulators. We have authority to invest up to $45 million in this wholly-owned subsidiary over the next three years. BETG will engage in demand side management activities through its wholly owned subsidiary Ener-G-Vision, Inc. and businesses involving electric transportation and the related infrastructure through its wholly-owned subsidiary TravElectric Services Corporation. We do not currently have a substantial investment in BETG and do not anticipate it significantly impacting our results of operations in the next several years.

In January 1994 BETG acquired a substantial majority interest in the assets of REZ-TEK International, Inc., a manufacturer of ozone water treatment systems. The new entity, which will be known as REZ-TEK International Corp., will continue the business of producing a system that treats cooling water used in commercial and industrial air conditioning systems in an energy efficient and environmentally sound manner.

Other Matters

Environmental

We are subject to numerous federal, state and local standards with respect to air and water quality, waste disposal and other environmental considerations. These standards can require that we modify our existing facilities or incur increased operating costs.

In 1991 we entered into a consent order with the Massachusetts Department of Environmental Protection (DEP) and other interested parties to undertake certain improvements in the emission control systems at New Boston Station. These improvements included the replacement of four existing chimney stacks with two taller stacks in order to improve the air quality in the vicinity of the station, and the installation of low nitrogen oxides burners. The capital cost of these modifications along with other associated improvements has been approximately $78 million through 1993 with an additional $3 million expected to complete these projects in 1994.

New Boston Station has the ability to burn natural gas, oil or both. As part of the DEP consent order we also agreed to operate the station using natural gas as fuel for a minimum of nine months per year beginning in April 1992. Beginning in April 1995 we will be required to operate the station fueled exclusively by natural gas, except in certain emergency circumstances. We have made arrangements for a nine month supply of natural gas to the station until April 1995 and are currently in the process of negotiating with natural gas suppliers and transporters concerning the economics and availability of natural gas to New Boston on a year-round basis after that time. Year-round gas supplies are currently not available to the station and, as a result, the outcome of our negotiations with natural gas suppliers and transporters and the impact on the operation of New Boston Station are uncertain.

The 1990 Clean Air Act Amendments will require a significant reduction in nationwide emissions of sulfur dioxide from fossil fuel-fired generating units. The reduction will be accomplished by restricting sulfur dioxide emissions through a market-based system of allowances. We believe that we will have allowances issued to us that are in excess of our needs and which may be marketable. Any gain from the sale of these may be subject to future regulatory treatment. Other provisions of the 1990 Clean Air Act Amendments involve limitations on emissions of nitrogen oxides from existing generating units. Combustion system modifications made to New Boston and Mystic Stations, including the installation of the low nitrogen oxides burners at New Boston, will allow the units to meet the provisions of the 1995 standards. Depending upon the outcome of certain air quality modeling studies, additional emission reductions may also be required by 1999. The extent of any additional reductions and the costs of any further modifications is uncertain at this time.

State regulations revised in 1993 require that properties where releases of hazardous materials occurred in the past be further cleaned up according to a timetable developed by the DEP. We are currently evaluating the potential costs associated with the cleanup of sites where we have been identified as the owner or operator. There are uncertainties associated with these potential costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of certain other multi-party hazardous waste sites in Massachusetts and other states. At the majority of these other sites we are one of many potentially responsible parties and our alleged share of the responsibility is a small percentage. We do not expect any of our potential cleanup liabilities to have a material impact on financial condition, although provisions for cleanup costs could have a material impact on quarterly earnings.

We presently dispose of low-level radioactive waste (LLW) generated at Pilgrim Station at licensed disposal facilities in Barnwell, South Carolina. As a result of developments which have occurred pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, our continued access to such disposal facilities has become severely limited and significantly increased in cost. Refer to Note D to the consolidated financial statements for further discussion regarding LLW disposal.

In recent years a number of published reports have discussed the possibility that adverse health effects may be caused by electromagnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Some scientific reviews conducted to date by several state and federal agencies have suggested associations between EMF and such health effects, while other studies have not substantiated such associations. We support further research into the subject and are participating in the funding of industry sponsored studies. We are aware that public concern regarding EMF in some cases has resulted in litigation, in opposition to existing or proposed facilities before regulators, or in requests for legislation or regulatory standards concerning EMF levels. We have not been significantly affected to date by these developments and cannot predict their potential impact on us, however, we continue to closely monitor all aspects of the EMF issue.

Litigation
In March 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel is vigorously defending this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on quarterly earnings.

Labor negotiations
We began negotiations involving our labor contracts in early February 1994. These contracts expire on May 15, 1994. We anticipate favorable resolution of these negotiations prior to that date.

New accounting pronouncements
We will adopt Statement of Financial Accounting Standards (SFAS) No. 112, Employers' Accounting for Postemployment Benefits, and SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, in the first quarter of 1994. Refer to Notes I and J to the consolidated financial statements for further discussion of these pronouncements.

Consolidated Statements of Income

(in thousands, except earnings per share)	1993	1992	1991
		years ended December 31,	
Operating revenues	$ 1,482,253	$ 1,411,753	$ 1,354,501
Operating expenses:			
Fuel	176,366	195,873	200,912
Purchased power	364,482	356,931	338,994
Other operations and maintenance	406,271	379,350	370,758
Depreciation and amortization	137,722	129,045	126,151
Amortization of deferred cost of cancelled nuclear unit	0	24,381	24,381
Amortization of deferred nuclear outage costs	6,546	4,901	2,443
Demand side management programs	37,504	8,221	1,674
Taxes - property and other	93,102	80,426	66,216
Income taxes	34,941	11,725	17,111
Total operating expenses	1,256,934	1,190,853	1,148,640
Operating income	225,319	220,900	205,861
Other income (expense), net	589	(2,074)	5,684
Operating and other income	225,908	218,826	211,545
Interest charges:			
Long-term debt	104,375	106,850	108,912
Other	9,778	12,525	16,947
Allowance for borrowed funds used during construction	(6,463)	(7,847)	(8,984)
Total interest charges	107,690	111,528	116,875
Net income	118,218	107,298	94,670
Preferred and preference dividends provided	15,705	16,550	17,611
Balance available for common stock	$ 102,513	$ 90,748	$ 77,059
Common shares outstanding (weighted average)	44,959	43,144	39,348
Earnings per share of common stock	$ 2.28	$ 2.10	$ 1.96

Consolidated Statements of Retained Earnings

(in thousands)	1993	1992	1991
		years ended December 31,	
Balance at beginning of year	$ 192,948	$ 174,477	$ 161,143
Net income	118,218	107,298	94,670
Subtotal	311,166	281,775	255,813
Cash dividends declared:			
Preferred stock	15,705	14,923	9,476
Preference stock	0	1,953	8,135
Common stock	77,169	71,951	63,725
Subtotal	92,874	88,827	81,336
Balance at end of year	$ 218,292	$ 192,948	$ 174,477

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

Consolidated Balance Sheets

(in thousands)		1993		December 31, 1992
Assets				
Property, plant and equipment, at original cost:				
Utility plant in service	$ 3,904,776		$ 3,629,727	
Less: accumulated depreciation	1,258,359	$ 2,646,417	1,177,294	$ 2,452,433
Nuclear fuel	273,867		270,420	
Less: accumulated amortization	220,477	53,390	201,978	68,442
Construction work in progress		144,835		182,458
Total		2,844,642		2,703,333
Investments in electric companies, at equity		24,292		25,398
Nuclear decommissioning fund, at cost		66,060		50,871
Current assets:				
Cash and cash equivalents	8,768		3,947	
Accounts receivable	171,098		185,563	
Accrued unbilled revenues	29,823		28,564	
Fuel, materials and supplies, at average cost	79,381		93,931	
Prepaid expenses and other	9,738	298,808	6,644	318,649
Deferred debits:				
Power contracts	36,275		43,717	
Cancelled nuclear unit	19,067		19,067	
Nuclear outage costs	25,524		17,970	
Pension and postretirement costs	24,416		10,449	
Redemption premiums	59,116		40,506	
Regulatory asset - income taxes, net	26,916		0	
Other	52,183	243,497	64,274	195,983
Total assets		$ 3,477,299		$ 3,294,234
Capitalization and Liabilities				
Common stock equity		$ 876,479		$ 840,312
Cumulative preferred stock:				
Non-mandatory redeemable series		123,000		123,000
Mandatory redeemable series		96,000		98,000
First mortgage bonds		40,000		631,825
Sewage facility revenue bonds, net		32,497		24,248
Debentures		1,200,000		385,000
Unsecured medium-term notes		0		50,000
Current liabilities:				
Long-term debt/preferred stock due within one year	$ 2,000		$ 6,800	
Notes payable	204,151		275,500	
Accounts payable	144,760		154,251	
Interest accrued	25,467		21,497	
Dividends payable	22,696		22,192	
Other	27,336	426,410	12,482	492,722
Deferred credits:				
Power contracts	36,275		43,717	
Accumulated deferred income taxes	484,796		448,720	
Accumulated deferred investment tax credits	71,140		75,213	
Nuclear decommissioning reserve	73,744		57,165	
Other	16,958	682,913	24,312	649,127
Commitments and contingencies		-		
Total capitalization and liabilities		$ 3,477,299		$ 3,294,234

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

Consolidated Statements of Cash Flows

(in thousands)	1993	years ended December 31, 1992	1991
Cash flows from operating activities:			
Net income	$ 118,218	$ 107,298	$ 94,670
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	130,074	123,243	121,572
Amortization of nuclear fuel	21,816	25,473	19,869
Amortization of deferred cost of cancelled nuclear unit, net	0	22,340	21,112
Other amortization	9,433	2,132	1,696
Allowance for funds used during construction	(6,463)	(7,847)	(8,984)
Deferred income taxes	10,303	17,165	24,476
Investment tax credits	(4,073)	(4,273)	(4,290)
(Deferral) amortization of nuclear outage costs, net	(7,554)	4,901	(22,062)
Net changes in:			
Accounts receivable and accrued unbilled revenues	13,206	(18,188)	(3,519)
Fuel, materials and supplies	9,722	(2,330)	12,716
Accounts payable	(9,491)	41,899	(19,510)
Rate and contract settlements	(175)	(31,363)	(44,546)
Other current assets and liabilities	16,408	(2,565)	3,079
Other, net	(4,958)	(13,777)	(24,588)
Net cash provided by operating activities	296,466	264,108	171,691
Cash flows provided (used) by investing activities:			
Plant and nuclear fuel (excluding AFUDC)	(253,885)	(231,025)	(214,213)
Capitalized demand side management costs	(37,156)	(11,469)	0
Decommissioning fund	(15,189)	(7,210)	(5,896)
Investments in electric companies	1,106	1,836	(1,515)
Net cash used by investing activities	(305,124)	(247,868)	(221,624)
Cash flows provided (used) by financing activities:			
Issuances:			
Common stock	10,823	68,345	68,800
Preferred stock	40,000	40,000	50,000
Long-term debt	815,000	60,000	146,120
Redemptions:			
Debt retirements	(648,625)	(123,600)	(118,600)
Preferred/preference stock	(40,000)	(40,333)	(50,000)
Net change in short-term debt	(71,349)	65,200	35,770
Dividends paid	(92,370)	(86,184)	(79,545)
Net cash provided (used) by financing activities	13,479	(16,572)	52,545
Net increase (decrease) in cash and cash equivalents	4,821	(332)	2,612
Cash and cash equivalents at the beginning of the year	3,947	4,279	1,667
Cash and cash equivalents at the end of the year	$ 8,768	$ 3,947	$ 4,279

Cash paid during the year for:			
Interest, net of amounts capitalized	$ 103,720	$ 113,076	$ 115,488
Income taxes	$ 30,305	$ 10,095	$ 18,979

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

Note A. Significant Accounting Policies

1. Basis of Consolidation and Accounting

The consolidated financial statements include the activities of our wholly-owned subsidiaries, Harbor Electric Energy Company and Boston Energy Technology Group. All significant intercompany transactions have been eliminated.

We follow accounting policies prescribed by our federal and state regulators. We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The financial statements comply with generally accepted accounting principles. Certain prior period amounts on the financial statements were reclassified to conform with current presentation.

2. Revenue Recognition

We record revenues for electricity used by our customers, but not yet billed, in order to more closely match revenues with expenses.

3. Forecasted Fuel and Purchased Power Rates

The rate charged to retail customers for fuel and purchased power allows for all fuel costs, the capacity portion of some purchased power costs and some transmission costs to be billed to customers monthly using a forecasted rate. The difference between actual and estimated costs is included in accounts receivable on our consolidated balance sheets until subsequent rates are adjusted. State regulators have the right to reduce our subsequent fuel rates if they find that we have been unreasonable or imprudent in the operation of our generating units or in purchasing fuel.

4. Depreciation and Nuclear Fuel Amortization

Our physical property was depreciated on a straight-line basis in 1993, 1992 and 1991 at composite rates of approximately 3.09%, 3.36% and 3.41% per year, respectively, based on estimated useful lives of the various classes of property. The cost of decommissioning Pilgrim Station, our nuclear unit, is excluded from the depreciation rates. When property units are retired, their cost, net of salvage value, is charged to accumulated depreciation.

The cost of nuclear fuel is amortized based on the amount of energy Pilgrim Station produces. Nuclear fuel expense also includes an amount for the estimated costs of ultimately disposing of the spent nuclear fuel and for the decontamination and decommissioning of the United States enrichment facilities used in the production of nuclear fuel. These costs are recovered from our customers through fuel charges.

5. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated costs to finance plant expenditures. In accordance with regulatory accounting, AFUDC is included as a cost of utility plant. AFUDC is not an item of current cash income, but payment is received for these costs from customers over the service life of the plant in the form of increased revenues collected as a result of higher depreciation expense. Our AFUDC rates in 1993, 1992 and 1991 were 3.62%, 4.48%, and 6.85%, respectively, and represented only the cost of debt.

6. Cash and Cash Equivalents

Cash and cash equivalents are comprised of highly liquid securities with maturities of three months or less.

7. Allowance for Doubtful Accounts

Our accounts receivable are substantially all recoverable. This recovery occurs both from customer payments and from the portion of customer charges that provides for the recovery of bad debt expense. Accordingly, we do not maintain a significant allowance for doubtful accounts balance.

8. Deferred Debits

Deferred debits consist primarily of costs incurred which will be collected from customers through future charges in accordance with agreements with our state regulators. These costs will be expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. A portion of these costs is currently being charged to and collected from customers.

9. Amortization of Discounts, Premiums and Redemption Premiums on Securities

We expense discounts, premiums, redemption premiums and related expenses associated with issuances of securities or refinancing of existing securities in equal annual installments over the life of the replacement securities subject to regulatory approval.

Note B. Retail Settlement Agreements

In 1992 and 1989 our state regulators, the Massachusetts Department of Public Utilities, approved three-year settlement agreements relating to our rate case proceedings. These agreements provided for retail rate increases, accounting adjustments and demand side management program expenditures; clarified the timing and recognition of certain expenses and set limits on our rate of return on common equity. Refer to Management's Discussion and Analysis for further information related to these settlement agreements.

The settlement agreements did not affect our contract or wholesale power rates charged to other utilities, which are regulated by our federal regulators, the Federal Energy Regulatory Commission.

Note C. Income Taxes

In the first quarter of 1993 we prospectively adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). This required us to change our methodology of accounting for income taxes from the deferred method to an asset and liability approach. The deferred method of accounting was based on the tax effects of timing differences between income for financial reporting purposes and taxable income. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. In accordance with SFAS 109 we recorded a net regulatory asset of $26.9 million and a corresponding net increase in accumulated deferred income taxes as of December 31, 1993. The regulatory asset represents the additional future revenues to be collected from customers for deferred income taxes.

Accumulated deferred income taxes on our consolidated balance sheet at December 31, 1993 includes $587.8 million of gross deferred income tax liabilities net of $103.0 million of gross deferred income tax assets. We have approximately $19 million of alternative minimum tax carryforwards available at December 31, 1993. The major components of accumulated deferred income taxes are a result of differences between book and tax expenses relating to property, plant and equipment.

Deferred income tax expense reflected in our consolidated income statements is incurred when certain income and expenses are reported on the tax return in different years than reported in the financial statements. Investment tax credits are included in income over the estimated useful lives of the related property.

Components of income tax expense are as follows:

(in thousands)	1993	1992	1991
Excess tax depreciation over book depreciation	$ 12,382	$ 9,765	$ 10,802
Deferred fuel expense	(3,142)	2,587	56
Debt portion of allowance for funds used during construction	2,114	2,495	2,856
Massachusetts corporate franchise tax	5,089	6,134	7,140
Deferred nuclear outage expense	2,472	(1,558)	7,014
Cost of removal	3,272	6,904	4,277
Rate and contract settlements	0	10,013	10,196
Municipal property taxes	(489)	3,351	3,745
Demand side management programs	3,775	2,978	2,256
Cancelled nuclear unit	0	(4,621)	(8,998)
Reversal of deferred taxes - settlement agreement, net	(19,231)	(23,000)	(13,000)
Adjustment of prior year income tax accrual	(2,154)	4,134	2,563
Call premiums on refunded bond issues	5,821	1,029	(288)
Trust contributions - postretirement benefits	3,451	0	0
Other	(3,057)	(3,828)	(5,395)
Subtotal deferred income taxes	10,303	16,383	23,224
Current income tax expense	28,711	(385)	(1,823)
Investment tax credits	(4,073)	(4,273)	(4,290)
Provision for income taxes	34,941	11,725	17,111
Taxes on other income:			
Current	1,205	(2,348)	405
Deferred	0	782	1,252
Subtotal	1,205	(1,566)	1,657
Total income tax expense	$ 36,146	$ 10,159	$ 18,768

The effective income tax rates reflected in the consolidated financial statements and the reasons for their differences from the statutory federal income tax rate are explained below:

	1993	1992	1991
Statutory tax rate	**35.0%**	34.0%	34.0%
State income tax, net of federal income tax benefit	**4.2**	3.9	4.1
Investment tax credits	**(2.6)**	(3.6)	(3.8)
Municipal property tax adjustment	**(0.6)**	(1.6)	(1.6)
Adjustment of deferred taxes on cancelled nuclear unit	**-**	2.7	-
Reversal of deferred taxes - settlement agreement	**(13.0)**	(19.6)	(11.5)
Federal tax benefit of mandated payments from settlement agreements	**-**	(6.2)	(3.3)
Other	**0.4**	(0.9)	(1.4)
Effective tax rate	**23.4%**	8.7%	16.5%

Note D. Estimated Future Costs of Disposing of Spent Nuclear Fuel and Retiring Nuclear Generating Plants

The existing fuel storage facility at Pilgrim Station includes sufficient room for spent nuclear fuel generated through early 1995. We have a request for a license amendment pending before the Nuclear Regulatory Commission (NRC) to allow modification of the storage facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012. The NRC is reviewing our request and we expect approval in 1994. At that time we will initially modify the facility to provide spent fuel storage capacity through approximately 2003. It is the ultimate responsibility of the United States Department of Energy (DOE) to permanently dispose of spent nuclear fuel as required by the Nuclear Waste Policy Act of 1982. We currently pay a fee of $1.00 per net megawatthour sold from Pilgrim Station generation under a nuclear fuel disposal contract with the DOE. The fee is collected from customers through fuel charges.

When Pilgrim Station's operating license expires in 2012 we will be required to decommission the plant. During rate proceedings we provided our regulators a 1991 study documenting a cost of $328 million to decommission the plant. The study is based on the "green field" method of decommissioning, which provides for the plant site to be completely restored to its original state. We are expensing these estimated decommissioning costs over Pilgrim's expected service life. The 1993 expense of approximately $13 million is included in depreciation expense on the consolidated income statements. We receive recovery of this expense from charges to our retail customers and from other utility companies and municipalities who purchase a contracted amount of Pilgrim's electric generation. The funds we collect from decommissioning charges are deposited in an external trust and are restricted so that they may only be used for decommissioning and related expenses. The net earnings on the trust funds, which are also restricted, increase the nuclear decommissioning fund balance and nuclear decommissioning reserve, thus reducing the amount to be collected from customers. The 1991 decommissioning study has been partially updated for internal planning purposes to evaluate the potential financial impact of long-term spent fuel storage options resulting from delays in DOE spent fuel removal on the estimated decommissioning cost. The partial update indicates an estimated decommissioning cost of approximately $400 million in 1991 dollars based upon a revised spent fuel removal schedule and utilization of dry spent fuel storage technology. We will continue to monitor DOE spent fuel removal schedules and developments in spent fuel storage technology along with their impact on the decommissioning estimate.

We are also an investor in two other domestic nuclear units. Both of these units receive through the rates charged to their customers an amount to cover the estimated cost to dispose of their spent nuclear fuel and to retire the units at the end of their useful lives.

We presently dispose of low-level radioactive waste (LLW) generated at Pilgrim Station at licensed disposal facilities in Barnwell, South Carolina. As a result of developments which have occurred pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, our continued access to such disposal facilities has become severely limited and significantly increased in cost. We have access to the South Carolina site through July 1994, but do not presently believe that disposal site access will be provided after that date. Although legislation has been enacted in Massachusetts establishing a regulatory method for managing the state's LLW including the possible siting, licensing and construction of a LLW disposal facility within the state, it appears unlikely that such a facility will be constructed in a timely manner. Pending the construction of a disposal facility within the state or the adoption by the state of some other LLW management method, we continue to monitor the situation and are investigating other available options, including the possibility of on-site storage.

Note E. Cancelled Nuclear Unit

In May 1982 we began to expense the cost of our cancelled Pilgrim 2 nuclear unit over approximately eleven and one-half years in accordance with an order received from state regulators. We did not expense any of these costs in 1993. Instead, the remaining balance of approximately $19 million at December 31, 1993 and 1992 will be expensed in 1994 and/or 1995 as approved by our state regulators in our 1992 settlement agreement.

Note F. Capital Stock and Indebtedness

Capital Stock

(dollars in thousands, except per share amounts)	1993	1992	December 31, 1991
Common stock equity:			
Common stock, par value $1 per share, 100,000,000 shares authorized; 45,129,227, 44,763,055 and 42,047,356 shares issued and outstanding	$ 45,129	$ 44,763	$ 42,047
Premium on common stock	612,653	602,196	536,567
Retained earnings	218,292	192,948	174,477
Surplus invested in plant	405	405	405
Total common stock equity	$ 876,479	$ 840,312	$ 753,496

Cumulative preferred stock:

Par value $100 per share, 2,410,000 shares currently authorized; issued and outstanding:

Non-mandatory redeemable series:

Series	Current Shares Outstanding	Redemption Price/Share	1993	1992	1991
4.25%	180,000	$103.625	$ 18,000	$ 18,000	$ 18,000
4.78%	250,000	$102.800	25,000	25,000	25,000
7.75%	400,000	-	40,000	0	0
8.25%	400,000	-	40,000	40,000	0
8.88%	0	-	0	40,000	40,000
Total non-mandatory redeemable series			$ 123,000	$ 123,000	$ 83,000

Mandatory redeemable series:

Series	Current Shares Outstanding	1993	1992	1991
7.27%	480,000	$ 48,000	$ 48,000	$ 50,000
8.00%	500,000	50,000	50,000	50,000
Total mandatory redeemable series		98,000	98,000	100,000
Less: due within one year		2,000	0	0
Total mandatory redeemable series, net		$ 96,000	$ 98,000	$ 100,000

Cumulative preference stock:

Par value $1 per share, 8,000,000 shares authorized; none currently issued and outstanding

Non-mandatory redeemable series:	1993	1992	1991
$1.46 series	$ 0	$ 0	$ 2,675
Premium on $1.46 series	0	0	35,658
Total preference stock	$ 0	$ 0	$ 38,333

Dividends Declared per Share

	1993	1992	1991
Common stock	$ 1.715	$ 1.655	$ 1.595
Preferred stock:			
4.25% series	$ 4.253	$ 4.250	$ 4.250
4.78% series	4.785	4.780	4.780
7.27% series	7.270	7.270	7.270
7.75% series	5.707	0	
8.00% series	8.000	8.000	1.3
8.25% series	8.250	5.278	
8.88% series	2.220	8.880	8.880
Preference stock:			
$1.46 series	$ 0	$ 0.365	$ 1.460
Stated rate auction preference stock	0	0	6.900

Indebtedness

(dollars in thousands)			1993	December 31, 1992
Long-term debt:				
First mortgage bonds:				
Series	Interest Rate	Maturity		
I	4.750%	1995	$ 0	$ 25,000
J	6.125%	1997	0	40,000
K	6.875%	1998	0	50,000
L	9.000%	1999	0	50,000
M	9.375%	2000	0	60,000
N	8.125%	2001	0	75,000
S	Variable	2002	25,000	25,000
Q	9.750%	2003	0	59,375
R	10.950%		0	44,250
P	9.250%		0	60,000
U	10.250%	2014	15,000	15,000
W	9.500%	2016	0	135,000
Total first mortgage bonds			40,000	638,625
Less: due within one year			0	6,800
Total first mortgage bonds, net			$ 40,000	$ 631,825
Sewage facility revenue bonds			$ 36,300	$ 36,300
Less: funds held by trustee			3,803	12,052
Total sewage facility revenue bonds, net			$ 32,497	$ 24,248
Debentures:				
8.875%, due 1995			$ 100,000	$ 100,000
5.125%, due 1996			100,000	0
5.700%, due 1997			100,000	0
5.950%, due 1998			100,000	0
6.800%, due 2000			65,000	0
6.050%, due 2000			100,000	0
6.800%, due 2003			150,000	0
9.875%, due 2020			100,000	100,000
9.375%, due 2021			125,000	125,000
8.250%, due 2022			60,000	60,000
7.800%, due 2023			200,000	0
Total debentures			$ 1,200,000	$ 385,000
Unsecured medium-term notes			$ 0	$ 50,000
Short-term debt:				
Notes payable:				
Bank loans			$ 106,501	$ 162,500
Commercial paper			97,650	113,000
Total notes payable			$ 204,151	$ 275,500

1. Common Stock

Since December 31, 1990, we issued the following shares of common stock:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
Balance December 31, 1990	38,998	$ 194,993	$ 314,822
Dividend reinvestment plan	449	2,181	6,844
Change in par value of common stock [(a)]	0	(157,727)	157,727
New issue [(b)]	2,600	2,600	57,174
Balance December 31, 1991	42,047	42,047	536,567
Dividend reinvestment plan	416	416	9,658
New issue [(c)]	2,300	2,300	55,971
Balance December 31, 1992	44,763	44,763	602,196
Dividend reinvestment plan [(d)]	366	366	10,457
Balance December 31, 1993	**45,129**	**$ 45,129**	**$ 612,653**

(a) In November 1991 our Articles of Organization were amended to increase authorized common stock from 50 million to 100 million shares and reduce the par value from $5 to $1 per common share.

(b) We used the net proceeds of the 1991 common stock issuance to retire $55 million of Series X, 11% first mortgage bonds.

(c) We used the net proceeds of the 1992 common stock issuance to reduce short-term debt.

(d) At December 31, 1993, the remaining authorized common shares reserved for future issuance under the Dividend Reinvestment and Common Stock Purchase Plan were 815,170 shares.

2. Cumulative Non-Mandatory Redeemable Preferred and Preference Stock

In June 1992 we issued 400,000 shares of 8.25% cumulative non-mandatory redeemable preferred stock at par. The stock is redeemable at $100 per share plus accrued dividends beginning in June 1997. These shares were sold in the form of 1.6 million depositary shares, each representing a one-fourth interest in a share of the preferred stock. We used the proceeds of this issue to fully retire the $1.46 series cumulative non-mandatory redeemable preference stock.

In May 1993 we issued 400,000 shares of 7.75% cumulative non-mandatory redeemable preferred stock at par. The stock is redeemable at $100 per share plus accrued dividends beginning in May 1998. These shares were sold in the form of 1.6 million depositary shares, each representing a one-fourth interest in a share of the preferred stock. We used the proceeds of this issue to fully retire the 8.88% series cumulative non-mandatory redeemable preferred stock.

3. Cumulative Mandatory Redeemable Preferred Stock

The 480,000 shares of our 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $104.36. The redemption price declines annually each May to par value in May 2002. In May 1993 the stock became subject to sinking fund requirements to retire 20,000 shares at $100 per share plus accrued dividends each year through May 2002. In 1992 we purchased 20,000 shares at a discount on the open market which satisfied the mandatory sinking fund requirement for May 1993. Beginning in 1993, we have the non-cumulative option each May to redeem additional shares, not to exceed 20,000, for the sinking fund at $100 per share plus accrued dividends.

We are not able to redeem any part of our 500,000 shares of $100 par value 8% series cumulative preferred stock prior to December 2001. The entire series is subject to mandatory redemption in December 2001 at $100 per share, plus accrued dividends.

4. Long-Term Debt

Substantially all our property, plant, equipment, materials and supplies are subject to lien under the terms of our Indenture of Trust and First Mortgage dated December 1, 1940, and its supplements. Currently only the outstanding Series S and U first mortgage bonds are subject to the terms of the indenture.

The aggregate principal amounts of our first mortgage bonds, debentures, and sewage facility revenue bonds (including sinking fund requirements) due in 1994 and 1995 are $0 and $100.6 million, respectively, and $101.6 million per year in 1996 through 1998.

Our first mortgage bonds, Series S, adjustable rate due 2002, paid interest at 9.2% per year for the period January 15, 1993 through January 14, 1994. The rate is adjusted annually and is based upon the ten-year constant maturity Treasury rate as published by the Federal Reserve Board. The interest rate for the period January 15, 1994 through January 14, 1995 is 8.2%.

In September 1992 we issued $60 million of 8.25% debentures which mature in September 2022. The debentures are redeemable at prices decreasing from 103.78% of par beginning in September 2002, to 100% of par beginning in September 2012. We used the net proceeds from the sale to reduce short-term debt. In October 1992 we redeemed the remaining balance of $45 million Series X first mortgage bonds.

In February 1993 we issued $65 million of 6.8% debentures due in 2000. We used the proceeds of this issue to reduce short-term debt. These debentures are not redeemable prior to maturity.

In March 1993 we issued $650 million of debentures and used the proceeds to retire ten of twelve outstanding series of first mortgage bonds and reduce short-term debt. The debentures were issued in five separate series with interest rates ranging from 5.125% to 7.8% and maturing between 1996 and 2023. The 5 1/8% debentures due 1996, 5.70% due 1997, 5.95% due 1998 and 6.80% due 2003 are not redeemable prior to maturity. The 7.80% debentures due 2023 are first redeemable in March 2003 at a redemption price of 103.73%. The redemption price decreases annually each March to par value in March 2013. There is no sinking fund requirement for any series of the debentures.

In August 1993 we issued $100 million of 6.05% debentures due in 2000. We used the proceeds from this sale to reduce short-term debt. These debentures are not redeemable prior to maturity and have no sinking fund requirements.

We redeemed $50 million of 9.65% medium-term notes in September 1992 and $50 million of 9.75% medium-term notes in September 1993.

5. Sewage Facility Revenue Bonds

In December 1991, Harbor Electric Energy Company (HEEC), a wholly-owned subsidiary, issued $36.3 million of long-term sewage facility revenue bonds. The bonds are tax-exempt, subject to annual mandatory sinking fund redemption requirements and mature in the years 1995-2015. The weighted average interest rate of the bonds is 7.3%. A portion of the proceeds from the bonds was used to retire $21 million of short-term sewage facility revenue bonds at maturity. The remainder of the proceeds, which is on deposit with the trustee, is being used to finance the construction of HEEC's permanent substation located on Deer Island (in Boston Harbor) and to fund an amount which must remain in reserve with the trustee. If HEEC should have insufficient funds to pay certain costs on a timely basis or be unable to meet certain net worth requirements, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $7 million.

6. Short-Term Debt

We have arrangements with certain banks to provide short-term credit on both a committed and an uncommitted and as available basis. We currently have authority to issue up to $350 million of short-term debt.

We have a $200 million revolving credit agreement with a group of banks. This agreement is intended to provide a standby source of short-term borrowings. Under the terms of this agreement we are required to maintain a common equity ratio of not less than 30% at all times. Commitment fees must be paid on the unused portion of the total agreement amount.

Information regarding our short-term borrowings, comprised of bank loans and commercial paper is as follows:

(thousands of dollars)	**1993**	1992	1991
Maximum short-term borrowings	$ **320,000**	$ 314,998	$ 324,400
Weighted average amount outstanding	$ **220,149**	$ 233,286	$ 221,481
Weighted average interest rates, excluding commitment fees	**3.4%**	4.1%	6.4%

Note G. Fair Value of Securities

The following methods and assumptions were used to estimate the fair value of each class of securities for which it is practicable to estimate the value:

Nuclear decommissioning fund

The fair value of $70.1 million is based on quoted market prices of securities held.

Cash and cash equivalents

The carrying amount of $8.8 million approximates fair value due to the short-term nature of these securities.

Mandatory redeemable cumulative preferred stock, first mortgage bonds, sewage facility revenue bonds and debentures

The fair values of these securities are based upon the quoted market prices of similar issues. Carrying amounts and fair values as of December 31, 1993 are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 98,000	$ 105,935
First mortgage bonds	40,000	44,132
Sewage facility revenue bonds	36,300	40,528
Debentures	1,200,000	1,237,924

Note H. Commitments and Contingencies

1. Capital Commitments

At December 31, 1993, we had estimated contractual obligations for plant and equipment of approximately $71 million.

2. Lease Commitments

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both noncancelable leases and transmission agreements for the years after 1993 are as follows:

(in thousands)

1994	$	27,375
1995		23,878
1996		21,299
1997		19,217
1998		17,969
Years thereafter		139,474
Total	$	249,212

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. Our total expense for both lease rentals and transmission agreements for 1993, 1992 and 1991 was $30 million, $30 million and $33.5 million, respectively, net of capitalized expenses of $5 million, $5 million, and $4.8 million, respectively.

3. Hydro-Quebec

We have an approximately 11% equity ownership interest in two companies which own and operate transmission facilities to import electricity from the Hydro-Quebec system in Canada, which is included in our consolidated financial statements. As an equity participant we are required to guarantee, in addition to our own share, the total obligations of those participants who do not meet certain credit criteria and are compensated accordingly. At December 31, 1993, our portion of these guarantees was approximately $22 million.

4. Yankee Atomic Electric Company

In February 1992 the Board of Directors of Yankee Atomic Electric Company (Yankee Atomic) decided to permanently discontinue power operation of the Yankee Atomic nuclear generating station and, in time, decommission that facility. We relied on Yankee Atomic for less than one percent of our system capacity. We have a 9.5% stock investment of approximately $2 million in Yankee Atomic.

In 1993 Yankee Atomic received approval from federal regulators to continue to collect its investment and decommissioning costs through July 2000, the period of the plant's operating license. The estimate of our share of Yankee Atomic's investment and costs of decommissioning is approximately $33 million as of December 31, 1993. This estimate is recorded on our consolidated balance sheet as a power contract liability in deferred credits. An offsetting power contract regulatory asset is included in deferred debits as we continue to collect these costs from our customers in accordance with our 1992 settlement agreement.

5. Nuclear Insurance

The federal Price-Anderson Act currently provides $9.4 billion of financial protection for public liability claims and legal costs arising from a single nuclear-related accident. The first $200 million of nuclear liability is covered by commercial insurance. Additional nuclear liability insurance up to approximately $8.8 billion is provided by a retrospective assessment of up to $75.5 million per incident levied on each of the 116 units licensed to operate in the United States, with a maximum assessment of $10 million per reactor per accident in any year. The additional nuclear liability insurance amount may change as new commercial nuclear units are licensed and existing units give up their licenses. In addition to the nuclear liability retrospective assessments, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection, each licensee can be assessed an additional five percent of the maximum retrospective assessment.

We have purchased insurance from Nuclear Electric Insurance Limited (NEIL) to cover some of the costs to purchase replacement power during a prolonged accidental outage at Pilgrim Station and the cost of repair, replacement, decontamination or decommissioning of our utility property resulting from covered incidents at Pilgrim Station. Our maximum potential total assessment for losses which occur during current policy years is approximately $14.6 million under both the replacement power and excess property damage, decontamination and decommissioning policies. All companies insured with NEIL are subject to retroactive assessments if losses are in excess of the total funds available to NEIL. While assessments may also be made for losses in certain prior policy years, we are not aware of any losses in those years which we believe are likely to result in an assessment.

6. Litigation

In March 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel is vigorously defending this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on quarterly earnings.

7. Hazardous Waste

State regulations revised in 1993 require that properties where releases of hazardous materials occurred in the past be further cleaned up according to a timetable developed by the Massachusetts Department of Environmental Protection. We are currently evaluating the potential costs associated with the cleanup of sites where we have been identified as the owner or operator. There are uncertainties associated with these potential costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of certain other multi-party hazardous waste sites in Massachusetts and other states. At the majority of these other sites we are one of many potentially responsible parties and our alleged share of the responsibility is a small percentage. We do not expect any of our potential cleanup liabilities to have a material impact on financial condition, although provisions for cleanup costs could have a material impact on quarterly earnings.

Note I. Pensions, Other Postretirement and Postemployment Benefits

1. Pensions

We have a noncontributory funded retirement plan, with certain features that allow voluntary contributions. Benefits are based upon an employee's years of service and compensation during the last years of employment. Our funding policy is to contribute each year an amount that is not less than the minimum required contribution under federal law or greater than the maximum tax deductible amount. Plan assets are primarily equities, bonds, insurance contracts and real estate.

Net pension cost included the following components:

(in thousands)	1993	1992	1991
Current service cost - benefits earned	$ 11,734	$ 10,683	$ 8,567
Interest cost on projected benefit obligation	33,181	32,287	29,817
Actual return on plan assets	(44,470)	(23,281)	(60,873)
Net amortization and deferral	8,528	(13,549)	26,811
Net pension cost (a)	$ 8,973	$ 6,140	$ 4,322

(a) In accordance with an agreement with our state regulators, we deferred our net pension costs in excess of the annual funding amounts and will recover these costs from customers over time. Net pension costs recorded as expense were approximately $5 million in 1993 and $0 in 1992 and 1991.

We used the following assumptions for calculating pension cost:

	1993	1992	1991
Discount rate	8.25%	8.25%	9.00%
Expected long-term rate of return on assets	10.00%	10.00%	10.00%
Compensation increase rate	4.50%	4.50%	4.50%

We changed our discount rate assumption to 7.0% for calculating pension cost effective January 1994.

The plan's funded status at December 31, 1993 and 1992 was as follows:

(in thousands)	1993	1992
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $384,150 and $322,836	$ 400,895	$ 339,035
Plan assets at fair value	$ 394,233	$ 392,407
Projected obligation for service rendered to date	(509,661)	(418,312)
Projected benefit obligation in excess of plan assets	(115,428)	(25,905)
Unrecognized prior service cost	8,139	8,817
Unrecognized net (gain) loss	75,352	(6,810)
Unrecognized net obligation	9,932	10,866
Net pension liability	$ (22,005)	$ (13,032)

We used the following assumptions for calculating the plan's year-end funded status:

	1993	1992
Discount rate	7.00%	8.25%
Compensation increase rate	4.50%	4.50%

2. Other Postretirement Benefits

In addition to pension benefits, we also currently provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. Effective January 1993 we adopted Statement of Financial Accounting Standards No. 106, Employer's Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). This requires us to record a liability during the working years of employees for the expected costs of providing their postretirement benefits other than pensions (PBOPs). Prior to 1993 our policy was to record the cost of PBOPs when paid. Our transition obligation on January 1, 1993 was approximately $183 million, which we elected to recognize over 20 years as permitted by SFAS 106. Our total cost of PBOPs under SFAS 106 in 1993 was approximately $28 million, an increase of approximately $18 million over costs incurred under our prior method of accounting for PBOPs. Our 1992 settlement agreement provides us with a phase-in of a portion of the increased costs and allows us to defer the additional costs in excess of the phase-in amounts to the extent that we fund an external trust. In December 1993 we deposited $18 million on a tax deductible basis into external trusts for the payment of PBOPs. Accordingly, in 1993 we recorded an expense of approximately $16 million, reflecting the amount of cost recovery from customers, and deferred approximately $12 million for future recovery. We capitalized approximately 19% of these costs.

Postretirement benefits cost consisted of the following in 1993:

(in thousands)

Current service cost - benefits earned	$	4,351
Interest cost on transition obligation		14,286
Amortization of transition obligation		9,151
Net postretirement benefits cost	$	27,788

We used an 8.0% weighted average discount rate and 4.5% rate of compensation increase assumption for calculating the transition obligation and the 1993 postretirement benefits cost. Our expected long-term rate of return on assets is 9.0%. We also assumed a 12.5% health care cost trend rate. Effective January 1, 1994 we changed the discount and health care cost trend rates to 7.0% and 9.0%, respectively, in order to more accurately estimate our future benefit payments. The health care cost trend rate is assumed to decrease by one percent each year to 5% in 1998 and years thereafter. Changes in the health care cost trend rate will affect our cost and obligation amounts. For example, a one percent increase in the rate would increase the total service and interest costs in 1993 by approximately 16% and would increase the accumulated obligation at December 31, 1993 by approximately 13%.

The postretirement benefits program's funded status at December 31, 1993 was as follows:

(in thousands)

Trust assets at fair value			$	18,016
Accumulated obligation for service rendered to date from:				
Retirees	$	(75,216)		
Active employees eligible to retire		(64,880)		
Active employees not eligible to retire		(73,285)		(213,381)
Accumulated benefit obligation in excess of trust assets				(195,365)
Unrecognized loss				21,497
Unrecognized net obligation				173,868
Net postretirement benefits liability			$	0

The trust assets consist of money market funds at December 31, 1993.

3. Postemployment Benefits

Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits, will be effective for the first quarter of 1994. This statement will require us to record a liability computed on an actuarial basis for the estimated cost of providing postemployment benefits. Postemployment benefits provided to former or inactive employees, their beneficiaries and covered dependents include salary continuation, severance benefits, disability-related benefits (including workers' compensation), job training and counseling and continuation of health care and life insurance coverage. We currently recognize the cost of these benefits primarily as claims are paid. We do not anticipate a material effect on net income from adopting this statement.

Note J. New Accounting Pronouncement

We will adopt Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities, in the first quarter of 1994. This statement may require us to classify the investments in our nuclear decommissioning fund on our consolidated balance sheet based on how long we intend to hold the individual securities. These investments may be classified as "available for sale" and we may also be required to report any unrealized gains and losses on the investments as a separate component of shareholders' equity. We do not expect the adoption of this statement to have a material effect on shareholders' equity.

Note K. Long-Term Power Contracts

1. Long-Term Contracts for the Purchase of Electricity

We purchase electric power under several long-term contracts for which we pay a share of the generating unit's capital and fixed operating costs through the contract expiration date. The total cost of these contracts is included in purchased power expense in our consolidated income statements. Information relating to these contracts as of December 31, 1993 is as follows:

Contract	Contract Expiration Date	Units of Capacity Purchased[a] %	Units of Capacity Purchased[a] MW	proportionate share (in thousands) 1993 Minimum Debt Service	1993 Interest Portion of Minimum Debt Service	Debt Outstanding Through Cont. Exp. Date
Canal Unit 1	2001	25.0	142	$ 781	$ 314	$ 2,118
Mass. Bay Transportation Authority	2005	100.0	35	(b)	(b)	(b)
Connecticut Yankee Atomic	2007	9.5	56	2,579	1,670	15,898
Ocean State Power - Unit 1	2010	23.5	65	5,323	3,948	22,747
Ocean State Power - Unit 2	2011	23.5	65	4,422	3,376	19,401
Northeast Energy Associates	(c)	(c)	219	(c)	(c)	(c)
L'Energia	2013	73.0	64	(d)	(d)	(d)
Total			646	$ 13,105	$ 9,308	$ 60,164

(a) The Northeast Energy Associates contract represents 6.4% of our total system generation capability. The remaining units listed above represent 12.6% in total.

(b) We are required to pay the greater of $22.00 per kilowatt-year or 90% of the New England Power Pool capability responsibility adjustment charge up to $63.00 per kilowatt-year times the qualified capacity (currently rated at 33.6MW) plus incremental operating, maintenance and fuel costs. The total charges for this contract in 1993 were approximately $2 million.

(c) We purchase approximately 75.5% of the energy output of this unit under two contracts. One contract represents 135MW and expires in the year 2015. The other contract is for 84MW and expires in 2010. We pay for this energy based on a price per kWh actually received. We do not pay a proportionate share of the unit's capital and fixed operating costs. The total charges for these contracts in 1993 were approximately $116 million.

(d) The L'Energia contract started in March 1993. We purchase 73% of the energy output of this unit. We pay for this energy based on a price per kWh actually received. The total charges under this contract for 1993 were approximately $15 million.

Our total fixed and variable costs for these contracts in 1993, 1992 and 1991 were approximately $225 million, $217 million and $154 million, respectively. Our minimum fixed payments under these contracts for the years after 1993 are as follows:

(in thousands)	
1994	$ 69,432
1995	72,418
1996	75,376
1997	71,147
1998	72,429
Years thereafter	725,236
Total	$ 1,086,038
Total present value	$ 558,600

2. Long-Term Power Sales

In addition to our power sales to four wholesale customers, we sell a percentage of Pilgrim Station's output to other utilities under long-term contracts. Information relating to these contracts is as follows:

Contract Customer	Contract Expiration Date	Units of Capacity Sold %	Units of Capacity Sold MW
Commonwealth Electric Company	2012	11.0	73.7
Montaup Electric Company	2012	11.0	73.7
Various municipalities	2000[a]	3.7	25.0
Total		25.7	172.4

(a) Subject to certain adjustments.

Under these contracts, the utilities pay their proportional share of the costs of operating Pilgrim Station and associated transmission facilities. These costs include operation and maintenance expenses, insurance, local taxes, depreciation, decommissioning and a return on capital.

To the Stockholders and Directors of Boston Edison Company

We have audited the accompanying consolidated balance sheets of Boston Edison Company and subsidiaries (the Company) as of December 31, 1993 and 1992 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1993 and 1992, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

Coopers & Lybrand

Boston, Massachusetts
January 25, 1994

Selected Consolidated Financial Statistics (Unaudited)

Quarterly Financial Data

(in thousands, except earnings per share)

	Operating Revenues	Operating Income	Net Income	Balance Available for Common Stock	Earnings Per Share of Common Stock [(a)]
1993					
First quarter	$ 354,752	$ 41,721	$ 15,452	$ 11,377	$ 0.25
Second quarter	346,074	49,282	22,829	19,125	0.43
Third quarter	436,024	96,319	70,015	66,052	1.47
Fourth quarter	345,403	37,997	9,922	5,959	0.13
1992					
First quarter	$ 343,505	$ 41,930	$ 13,816	$ 9,553	$ 0.23
Second quarter	300,566	32,629	4,953	852	0.02
Third quarter	408,255	100,890	73,698	69,593	1.60
Fourth quarter	359,427	45,451	14,831	10,750	0.24

(a) Based upon the weighted average number of common shares outstanding during the quarter.

Our electricity sales and revenues are seasonal in nature, with both being lower in the spring and fall seasons. Quarterly earnings for 1993 reflect a change in the months for which certain customers were billed at higher rates as mandated by our state regulators. These customers were billed at these higher rates in July through October in 1992 and in June through September in 1993. The change in billing increased second quarter earnings and reduced fourth quarter earnings by approximately $0.23 per share in 1993.

Quarterly Stock Data

Following are the reported high and low sales prices of our common stock on the New York Stock Exchange as reported daily in the *Wall Street Journal* for each of the quarters in 1993 and 1992 and the dividends declared per share during each of those quarters:

			1993			1992
	High	Low	Dividends	High	Low	Dividends
First quarter	$ 30 1/2	$ 26 3/8	$ 0.425	$ 24 5/8	$ 22 1/8	$ 0.410
Second quarter	30 7/8	27 7/8	0.425	26	22 3/8	0.410
Third quarter	32 5/8	29 3/4	0.425	26 7/8	24 7/8	0.410
Fourth quarter	32 1/4	27 7/8	0.440	28 1/4	24 3/4	0.425

Selected Consolidated Operating Statistics (Unaudited)

	1993	1992	1991	1990	1989
Capacity - MW:					
New Boston Station	**760**	760	760	760	760
Pilgrim Station	**670**	670	670	670	670
Mystic Station	**1,006**	1,005	1,015	1,014	1,018
W.F. Wyman Unit 4	**36**	36	36	36	36
Jet turbines	**283**	281	281	281	273
Total	**2,755**	2,752	2,762	2,761	2,757
Contract purchases	**938**	1,157	1,293	924	1,102
Contract sales	**(283)**	(303)	(293)	(173)	(171)
Net capability at year-end	**3,410**	3,606	3,762	3,512	3,688
Net capability at peak-MW	**3,663**	3,587	3,695	3,505	3,483
Capability responsibility to NEPOOL at peak-MW	**3,190**	3,396	3,311	3,393	3,443
Edison territory:					
Hourly peak-MW	**2,662**	2,545	2,652	2,548	2,626
Load factor	**60.5%**	62.5%	60.0%	62.2%	61.4%
Generating station economy: (BTU/net kWh)	**10,345**	10,234	10,331	10,403	10,309
Average cost of fuel (Company) - ¢ per million BTU:					
Fossil	**250.42**	246.69	240.18	255.51	254.56
Nuclear	**50.67**	52.18	56.18	59.05	56.79
Composite	**162.02**	166.93	180.49	191.48	223.86
Capability (net kW):					
Fossil	**84%**	81%	81%	81%	82%
Nuclear	**16%**	19%	19%	19%	18%
Generation (system kWh excluding interchange):					
Fossil	**68%**	69%	70%	72%	87%
Nuclear	**32%**	31%	30%	28%	13%
Utility plant ($ in 000's):					
Expenditures	**247,394**	213,621	202,589	240,902	234,253
Retirements	**34,147**	34,036	30,333	27,180	14,042
Accumulated depreciation	**1,258,359**	1,177,294	1,097,991	1,015,371	950,298
Depreciable plant	**3,841,752**	3,567,160	3,488,269	3,277,616	3,130,031
Number of employees at year-end	**4,404**	4,540	4,637	4,738	4,686

Selected Consolidated Sales Statistics (Unaudited)

	1993	1992	1991	1990	1989
Electric energy: (kWh in thousands)					
Sources (system output):					
Generated	**9,787,092**	11,679,824	10,602,110	12,744,238	11,679,060
Purchased	**5,326,224**	5,449,225	4,651,101	3,305,491	4,177,079
New England Power Pool	**1,575,310**	932,121	1,274,522	1,065,731	1,170,847
Total	**16,688,626**	18,061,170	16,527,733	17,115,460	17,026,986
Disposition:					
Retail sales:					
Commercial	**7,292,681**	7,202,580	7,132,179	7,183,347	7,095,297
Residential	**3,487,370**	3,424,275	3,382,306	3,430,720	3,413,801
Industrial	**1,590,669**	1,678,242	1,684,864	1,750,325	1,845,441
Other [a]	**145,242**	292,510	279,540	275,213	259,762
Total retail billed	**12,515,962**	12,597,607	12,478,889	12,639,605	12,614,301
Wholesale and contract sales [a]	**2,272,669**	2,517,247	1,660,082	1,674,114	1,138,682
New England Power Pool	**877,978**	1,898,059	1,252,797	1,885,165	2,090,238
Total system	**15,666,609**	17,012,913	15,391,768	16,198,884	15,843,221
Miscellaneous usage	**1,020,017**	1,048,257	1,135,965	916,576	1,183,765
Total	**16,686,626**	18,061,170	16,527,733	17,115,460	17,026,986
Kilowatthours - annual growth percent:					
Retail sales:					
Commercial	**1.3%**	1.0%	(0.7)%	1.2%	1.3%
Residential	**1.8**	1.2	(1.4)	0.5	(0.5)
Industrial	**(5.2)**	(0.4)	(3.7)	(5.2)	0.3
Other	**(50.3)**	4.6	1.6	6.0	16.9
Total retail billed [a]	**(0.6)**	1.0	(1.3)	0.2	0.9
Wholesale and contract sales	**(9.7)**	51.6	(0.8)	47.0	85.2
New England Power Pool	**(53.7)**	51.5	(33.5)	(9.8)	149.0
Total system	**(7.9)%**	10.5%	(5.0)%	2.2%	13.6%
Total electric operating revenues by class:					
Commercial	**49%**	47%	47%	46%	45%
Residential	**27%**	26%	26%	27%	26%
Industrial	**10%**	10%	10%	10%	10%
Wholesale and contract	**12%**	13%	12%	13%	15%
Other	**2%**	4%	5%	4%	4%
Electric sales statistics:					
Residential averages:					
Annual kWh use	**6,160**	6,101	6,053	6,150	6,160
Revenue per kWh	**11.49¢**	10.84¢	10.60¢	10.09¢	10.15¢
Annual bill	**$ 709.75**	$ 657.41	$ 641.62	$ 620.54	$ 625.24
Customers:					
Average number	**651,141**	646,215	642,967	642,041	637,871

(a) Effective February 1993 a former retail customer became a wholesale customer as allowed under Massachusetts state law. Excluding the effect of this customer's change in status, total retail sales billed increased 1.2% in 1993.

Certain reclassifications and recalculations were made to the data reported in prior years to conform with the method of presentation used in 1993.

Selected Consolidated Financial Statistics (Unaudited)

	1993	1992	1991	1990	1989
Operating revenues (000)	**$ 1,482,253**	$ 1,411,753	$ 1,354,501	$ 1,314,440	$ 1,339,956
Balance for common (000)	**$ 102,513**	$ 90,748	$ 77,059	$ 77,788	$ (33,788)
Per common share:					
Earnings (loss)	**$ 2.28**	$ 2.10	$ 1.96	$ 2.01[(a)]	$ (0.88)[(b)]
Dividends declared	**$ 1.715**	$ 1.655	$ 1.595	$ 1.535	$ 1.745
Dividends paid	**$ 1.70**	$ 1.64	$ 1.58	$ 1.52	$ 1.82
Book value	**$ 19.42**	$ 18.77	$ 17.92	$ 17.22	$ 16.73
Operating cash flow [(c)]	**$ 6.60**	$ 6.85	$ 5.50	$ 5.68	$ 6.39
Payout ratio	**75%**	78%	81%	76%	[(d)]
Return on average common equity	**11.9%**	11.5%	11.3%	11.8%	(4.6)%
Year-end dividend yield	**5.9%**	6.2%	6.6%	7.9%	7.6%
Fixed charge coverage (SEC)	**2.27x**	1.93x	1.86x	2.13x	0.52x
Capitalization:					
Total debt	**57%**	56%	58%	59%	57%
Preferred and preference equity	**9%**	9%	10%	10%	11%
Common equity	**34%**	35%	32%	31%	32%
Long-term debt (000)	**$ 1,272,497**	$ 1,091,073	$ 1,136,765	$ 1,074,025	$ 948,839
Mandatory redeemable preferred/ preference stocks (000)	**$ 98,000**	$ 98,000	$ 100,000	$ 100,000	$ 100,000
Total assets (000)	**$ 3,477,299**	$ 3,294,234	$ 3,119,285	$ 3,012,589	$ 2,876,691
Internal generation after dividends (000)[(c)]	**$ 186,938**	$ 207,348	$ 191,016	$ 187,954	$ 147,449
Plant and nuclear fuel expenditures (000)	**$ 253,885**	$ 231,025	$ 214,213	$ 255,784	$ 235,946
Internal generation [(c)]	**74%**	90%	89%	73%	62%
Common stockholders at year-end	**42,392**	44,063	44,687	45,826	49,149
Common shares outstanding:					
Weighted average	**44,959,050**	43,143,953	39,347,824	38,778,901	38,245,648
Year-end	**45,129,227**	44,763,055	42,047,356	38,998,531	38,526,085
Stock price - High	**32 5/8**	28 1/4	24 7/8	20 1/4	22 1/8
- Low	**26 3/8**	22 1/8	18 1/4	16 1/2	15 3/8
- Year-end	**29 3/4**	27 1/2	24 3/4	20	20
Year-end market value (000)	**$ 1,342,595**	$ 1,230,984	$ 1,040,672	$ 779,971	$ 764,913
Trading volume (shares)	**18,729,400**	26,460,900	17,464,300	19,652,300	29,938,900
Market/book (year-end)	**1.53x**	1.47x	1.38x	1.16x	1.20x
Price/earnings ratio (year-end)	**13.0**	13.1	12.6	10.0	[(d)]

(a) Includes $0.41 per common share from an accounting change.
(b) Includes $2.78 per common share loss applicable to rate and contract settlements.
(c) Excludes effect of rate and contract settlements.
(d) Not calculated based upon a loss per common share. A payout ratio of 96% and a price/earnings ratio of 10.5 were calculated based upon $1.90 earnings per common share, excluding the $2.78 per common share loss due to rate and contract settlements.

Certain reclassifications and recalculations were made to the data reported in prior years to conform with the method of presentation used in 1993.

Officers

Bernard W. Reznicek, Chairman of the Board and Chief Executive Officer

Thomas J. May, President and Chief Operating Officer

George W. Davis, Executive Vice President

E. Thomas Boulette, Senior Vice President - Nuclear

Cameron H. Daley, Senior Vice President - Power Supply

John J. Desmond, III, Senior Vice President - Legal

L. Carl Gustin, Senior Vice President - Marketing & Corporate Relations

John J. Higgins, Jr., Senior Vice President - Human Resources

Ronald A. Ledgett, Senior Vice President - Power Delivery

Charles E. Peters, Jr., Senior Vice President - Finance

Alison Alden, Vice President - Sales & Service

Marc S. Alpert, Vice President and Treasurer

C. Bruce Damrell, Vice President - Engineering, Operations & Services

Richard S. Hahn, Vice President - Technology Research & Development

Douglas S. Horan, General Counsel

Joel Y. Kamya, Vice President - Production Operations

Martin S. Karl, Vice President - Marketing

Edward S. Kraft, Vice President - Nuclear Operations and Station Director

Arthur P. Phillips, Jr., Vice President - Corporate Information Services

Robert J. Weafer, Jr., Vice President, Controller and Chief Accounting Officer

Theodora S. Convisser, Clerk of the Corporation

Donald Anastasia, Assistant Treasurer

James J. Judge, Assistant Treasurer and Director - Corporate Planning

Wayne R. Frigard, Assistant Clerk of the Corporation

Directors

a,d William F. Connell, Chairman and Chief Executive Officer, Connell Limited Partnership (metals recycling and processing and industrial production)

d,f Gary L. Countryman, Chairman of the Board and Chief Executive Officer, Liberty Mutual Insurance Company

George W. Davis, Executive Vice President, Boston Edison Company

a,e,f Thomas G. Dignan, Jr., Partner, Ropes & Gray (law firm)

b,c,d Charles K. Gifford, President, Bank of Boston Corporation (bank holding company) and The First National Bank of Boston

b,f Nelson S. Gifford, Former Vice Chairman, Avery Dennison Corporation (pressure-sensitive adhesives and materials, office products, product identification and control systems and specialty chemicals)

a,e Kenneth I. Guscott, General Partner, Long Bay Management Company (real estate development)

a,b,c Matina S. Horner, Executive Vice President, Teachers Insurance and Annuity Association and College Retirement Equities Fund

a,c Thomas J. May, President and Chief Operating Officer, Boston Edison Company

b,d Sherry H. Penney, Chancellor, University of Massachusetts at Boston

a,c Bernard W. Reznicek, Chairman and Chief Executive Officer, Boston Edison Company

e,f Herbert Roth, Jr., Former Chairman of the Board and Chief Executive Officer, LFE Corporation (traffic and industrial process control systems)

e,f Stephen J. Sweeney, Former Chairman of the Board and Chief Executive Officer, Boston Edison Company

b,c,d Paul E. Tsongas, Partner, Foley, Hoag & Eliot (law firm)

e,f Charles A. Zraket*, Trustee, The MITRE Corporation (not-for-profit system research and engineering firm)

a Member of Executive Committee
b Member of Audit, Finance and Risk Management Committee
c Member of Pricing Committee
d Member of Executive Personnel Committee
e Member of Nuclear Oversight Committee
f Member of Capital Investment Committee

* Will retire on April 22, 1994.

Dividend Reinvestment Plan

Our Dividend Reinvestment and Common Stock Purchase Plan (the plan) is available to our common and preferred stockholders. Under the plan, common and preferred stockholders may have their dividends reinvested in our common stock at current market prices. All participants may invest optional cash contributions, up to a maximum of $5,000 per quarter, which will be invested at the current market price. Participants do not pay fees or commissions.

All recordholders of shares of common and preferred stock are eligible to participate directly in the plan. Beneficial owners of our stock whose shares are registered in names other than their own (e.g., a broker or bank nominee) must arrange participation with the recordholder. If for any reason a beneficial owner is unable to arrange participation with their broker or bank nominee, they must become a recordholder by having the shares transferred to their own name.

All correspondence concerning changes in plan ownership should be directed to the plan agent:

The First National Bank of Boston
Dividend Reinvestment Unit
Mail Stop: 45-01-06
P. O. Box 1681
Boston, Massachusetts 02105-1681

Important Stockholder Information

Annual Meeting

Our Annual Meeting of Stockholders will be held on April 22, 1994, at 11:00 a.m. If you wish to receive a copy of Bernie Reznicek's remarks, please write to our Investor Relations Department at the General Offices address listed below.

Company Contact

Theodora Convisser

Clerk of the Corporation

Investor Relations Contact

Dan Desjardins

Director, Investor Relations

General Offices

800 Boylston Street, Boston, Massachusetts 02199-8003

(617) 424-2000

Stock Listings

New York and Boston stock exchanges

Stock Symbol

BSE

Dividend Payment Dates

Common and Preferred:

1st of February, May, August, November

Tax Status of 1993 Dividends

Generally, unless you are subject to certain exemptions, all dividends on our common or preferred stock are to be considered 100% taxable.

Stock Transfer Agent, Registrar of Stock and Dividend Reinvestment Plan Agent

The First National Bank of Boston

SEC Form 10-K

Stockholders may obtain a copy of our annual report to the Securities and Exchange Commission on Form 10-K by making a written request to our Investor Relations Department.

Quarterly Report to Shareholders

Beneficial owners of our stocks whose shares are registered in names other than their own (e.g., a broker or bank nominee) may obtain copies of our Quarterly Reports to Shareholders on an on-going basis by making a written request to our Investor Relations Department to be placed on their mailing list. Note that the Annual Report will continue to be mailed to beneficial owners directly by their bank or broker.

Inquiries Concerning Stock

If you have questions concerning your dividend payments, dividend direct deposit, dividend reinvestment plan status, transfer procedures or other stock account matters, please contact our Stock Transfer Agent at the following address:

The First National Bank of Boston
Shareholder Services Division
Mail Stop: 45-02-09
P. O. Box 644
Boston, Massachusetts 02102-0644

If you are submitting documents requesting a transfer, address change or account consolidation, please use this same address with **Mail Stop: 45-01-05.** If you would like to contact the bank by telephone call **617-575-2900** or toll-free **1-800-442-2001**.

Boston Edison
Investor Relations P356
800 Boylston Street
Boston, Massachusetts 02199-8003

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1993

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from ________ to ________

Commission file number 1-2301

BOSTON EDISON COMPANY

(Exact name of registrant as specified in its charter)

Massachusetts	**04-1278810**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
800 Boylston Street, Boston, Massachusetts	**02199**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 617-424-2000

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

Title of each class	Name of each exchange on which registered
Common stock, par value $1 per share	New York Stock Exchange Boston Stock Exchange
Cumulative preferred stock:	
7.75% Series, par value $100 per share (represented by depositary shares-each represents one-fourth interest in par value)	New York Stock Exchange
8.25% Series, par value $100 per share (represented by depositary shares-each represents one-fourth interest in par value)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES X NO __

The aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 1994 computed by reference to the last reported sale price of the common stock, $1 par value, of the registrant of the New York Stock Exchange composite tape on that date: $1,220,739,336.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 28, 1994
Common Stock, $1 par value	45,212,568 shares

DOCUMENTS INCORPORATED BY REFERENCE

Part	Document
III	Portions of definitive Proxy Statement dated March 17, 1994 for Annual Meeting of Stockholders to be held April 22, 1994.

Exhibit list appears on page 51.

Boston Edison Company

Form 10-K Annual Report

December 31, 1993

Part I

Item 1. Business

(a) General Development of Business

Boston Edison Company (the Company) is an investor-owned regulated public utility incorporated in 1886 under Massachusetts law. The Company operates in the energy and energy services business, which includes the generation, purchase, transmission, distribution and sale of electric energy and the development and implementation of demand side management (DSM) programs.

In 1993 the Company established an unregulated subsidiary known as the Boston Energy Technology Group (BETG) following approval from the Massachusetts Department of Public Utilities (DPU). The Company was granted authority to invest up to $45 million in this wholly-owned subsidiary over the next three years. BETG will engage in demand side management, electric transportation and electric generation and distribution activities through its wholly-owned subsidiaries Ener-G-Vision, Inc. and TravElectric Services Corporation. In January 1994 BETG acquired a substantial majority interest in the assets of REZ-TEK International, Inc. The new entity, REZ-TEK International Corporation, will continue the business of manufacturing ozone water treatment systems. The Company does not currently have a substantial investment in BETG and does not expect the subsidiary to significantly impact the results of operations in the next several years.

(b) Financial Information about Industry Segments

The Company operates primarily as a regulated electric public utility, therefore industry segment information is not applicable.

(c) Narrative Description of Business

Principal Products and Services

The Company supplies electricity at retail to an area of approximately 590 square miles encompassing the City of Boston and 39 surrounding cities and towns. The population of the area served with electricity at retail is approximately 1.5 million. In 1993 the Company served an average of approximately 651,000 customers. The Company also supplies electricity at wholesale for resale to other utilities and municipal electric departments. Revenues by class for the last three years are as follows:

	1993	1992	1991
Retail electric revenues:			
Commercial	49%	47%	47%
Residential	27%	26%	26%
Industrial	10%	10%	10%
Other	2%	4%	5%
Wholesale and contract revenues	12%	13%	12%

Sources and Availability of Fuel

The Company's generating units, other than Pilgrim Nuclear Power Station, are fueled by oil, natural gas or both. The Company's generation by type of fuel and the cost of fuel for each of the last five years are as follows:

	Percentage of Company Generation by Source (%)					Average Cost (Dollars per Million) of BTU's on a Burned Basis ($)				
	1993	1992	1991	1990	1989	1993	1992	1991	1990	1989
Oil	31.3	33.7	42.8	33.6	53.7	2.38	2.40	2.60	2.76	2.67
Gas	24.3	25.7	24.9	33.3	31.7	2.67	2.55	2.08	2.35	2.34
Nuclear	44.4	40.6	32.3	33.1	14.6	0.51	0.52	0.56	0.59	0.57

The majority of the Company's residual oil purchases consists of imported oil acquired primarily from international suppliers. The Company has contracts with major oil companies that can supply most of its estimated requirements, assuming no major disruptions in oil producing regions. Within contract provisions, the Company has the ability to purchase significant amounts of oil in the spot market when it is economical to do so.

Most of the Company's natural gas is supplied on an interruptible basis whereby a contract permits interruptions in deliveries by the supplier when natural gas pipeline capacity is unavailable. Deliveries of natural gas to the Company's generating units from suppliers may also be dependent on the availability of pipeline capacity to the New England region and competitive forces prevailing in the pipeline industry. Beginning in April 1995 the Company will be required to operate New Boston Station using exclusively natural gas as fuel, except in certain emergency circumstances, as part of a 1991 consent order from the Massachusetts Department of Environmental Protection (DEP). The Company has arrangements for a nine month supply of natural gas to the station until April 1995 and is currently in the process of negotiating with suppliers and transporters concerning the economics and availability of natural gas to the station on a year-round basis after that time. Year-round gas supplies are currently not available to the station and, as a result, the outcome of the Company's negotiations with natural gas suppliers and transporters and the impact on the operation of New Boston Station are uncertain.

In order to obtain nuclear fuel for use at Pilgrim Station the Company must obtain supplies of uranium concentrates and secure contracts for these concentrates to go through the processes of conversion, enrichment and fabrication of nuclear fuel assemblies. The Company currently has contracts for supplies of uranium concentrates and the processes of conversion, enrichment and fabrication that will individually allow operation of Pilgrim Station through 1998, 2000, 2001 and 2012, respectively.

Franchises

Through its charter, which is unlimited in time, the Company has the right to engage in the business of producing and selling electricity, steam and other forms of energy, has powers incidental thereto and is entitled to all the rights and privileges of and subject to the duties imposed upon electric companies under Massachusetts laws. The locations in public ways for the Company's electric transmission and distribution lines are obtained from municipal and other state authorities, which in granting these locations act as agents for the state. In some cases the action of these authorities is subject to appeal to the DPU. The locations are unlimited in time, but their rights are not vested and are subject to the action of these authorities and the legislature.

Seasonal Nature of Business

The Company's kWh sales and revenues have historically been less in the spring and fall than during winter and summer as sales tend to vary with weather conditions. In addition, the Company bills higher base rates to commercial and industrial customers during the billing months of June through September as mandated by the DPU. Accordingly, a significant portion of annual earnings occurs in the Company's third quarter. See Selected Consolidated Quarterly Financial Data (Unaudited) in Item 8.

Working Capital Practices

The Company has no special practices with respect to working capital that would be considered unusual for the electric utility industry or significant for the understanding of the Company's business.

Customer Dependence

No material portion of the Company's business is dependent upon one or a few customers.

Government Contracts

No material portion of the Company's business is subject to renegotiation or termination of government contracts or subcontracts.

Competitive Conditions

The Company is experiencing a substantial increase in competition from other electric utilities and non-utility generators to sell electricity for resale. In response to the current environment the Company has secured long-term power supply agreements with its four current wholesale customers which set rates principally through the year 2002. The Company also obtained a new wholesale customer for which it will provide up to 30 megawatts (MW) of contract demand power for ten years beginning November 1994.

The DPU has created an integrated resource management (IRM) process in which electric utilities forecast their future energy needs and propose how they will meet those needs by balancing conservation programs with all other supplies of energy. The Company submitted a draft IRM filing in March 1994 that covers the period 1994 through 2004. In this filing the Company concluded that adequate resources exist to meet customer needs for continued reliable, low cost power through the period without procurement of any new generation resources. The IRM process requires a settlement period in which intervenors and other interested parties have the opportunity to review, comment and request information on the draft filing. Any settlements reached will be reflected in the Company's final IRM filing to be submitted in July 1994. Any remaining issues will be litigated at the DPU through formal proceedings.

Direct competition with other electric utilities for retail electricity sales is still subject to substantial limitations, but these limitations may be reduced in the future. The Company and other Massachusetts electric utilities are protected in several ways by the DPU and municipal statutes against other utilities offering service to retail customers in their service areas. Another electric utility may not extend its service area to include municipalities other than those named in its agreement of association or charter without DPU authorization granted after notice and public hearing. Also, another company may not obtain an initial location for its lines in a municipality served by the Company without the approval of municipal authorities, subject to the right of appeal to the DPU. Additionally, a municipality may not engage in the electric utility business without complying with statutes requiring specific city or town approval and the purchase of Company property within municipality limits.

However, the Company is currently experiencing some forms of competition in the retail electric market. Current legislation allows industrial and large commercial customers to own and operate their own electric generating units. Retail customers may also substitute natural gas or oil for electricity as fuel for heating and cooling purposes. The Company is responding to the current and anticipated competitive pressures with a commitment to cost control and increased operating efficiencies without sacrificing quality of service or profitability.

Research Activities

The Company actively participates in several industry-sponsored research activities. These expenditures, included in other operations and maintenance expense on the consolidated income statements in Item 8, were not material in 1993.

Environmental Matters

The Company is subject to numerous federal, state and local standards with respect to air and water quality, waste disposal and other environmental considerations. These standards can require modification of existing facilities or curtailment or termination of operations at facilities, delay construction of new facilities or increase capital and operating costs by substantial amounts. Noncompliance with certain standards can, in some cases, also result in the imposition of monetary civil penalties. The Company believes that its operating facilities are in substantial compliance with currently applicable statutory and regulatory environmental requirements.

The Company's capital expenditures for environmental purposes during the five years 1989 through 1993 were approximately $125 million. Environmental-related capital expenditures for the years 1994 through 1998 are currently expected to approximate $43 million, including $17 million in 1994 and $9 million in 1995. These amounts exclude costs associated with asbestos removal which were approximately $11 million during the five years 1989 through 1993 and are currently expected to be approximately $10 million for the years 1994 through 1998. The 1994 expected capital expenditures for environmental purposes include costs to complete modifications at New Boston Station in order to improve air quality and reduce emissions of nitrogen oxides, as discussed in the *Environmental* section of Other Matters in Item 7, and to install air monitoring systems at other Company generating units.

Substantial additional expenditures could be required as changes in environmental requirements occur.

The Company is subject to regulation by the United States Environmental Protection Agency (EPA) and the Massachusetts Department of Environmental Protection (DEP) with respect to discharges of effluent from the Company's generating stations into receiving waters. The Federal Clean Water Act and the Massachusetts Clean Waters Act require the Company to receive permits that limit discharges in accordance with applicable water quality standards and are subject to renewal every five years. The Company has received discharge permits as required by the EPA and the DEP for each of its electric generating stations.

The Company is also subject to EPA and DEP regulation relative to emissions from its fossil-fired generating units pursuant to Federal and Massachusetts clean air laws, including the 1990 Clean Air Act Amendments. These regulations require the installation of various emissions controls and the use of low sulfur content fuels in certain cases. The Company's current status regarding compliance with DEP regulations and the 1990 Clean Air Act Amendments is discussed in the *Environmental* section in Item 7.

The Company is subject to various federal, state and local laws and regulations pertaining to the generation, treatment, transportation, storage and disposal of certain hazardous substances and to the cleanup of locations where such substances have either been disposed of or spilled. One of the requirements of these laws and regulations is that certain facilities which treat, store or dispose of hazardous wastes must be licensed. The only facility owned by the Company which requires such a license is Pilgrim Station. Currently Pilgrim Station has received interim status approval for the treatment and storage of certain wastes that are both hazardous and radioactive.

The Company has exposure to potential joint and several liability for the cleanup of sites where hazardous wastes may have been spilled or disposed of in the past. The Company has been notified of such potential liability for approximately twelve sites, most of which involve numerous parties. Complex litigation or negotiations among the parties and with regulatory authorities is in process concerning the scope and cost of cleanup and the sharing of costs among the potentially responsible parties for several of these sites. The Company also faces additional exposure for the cleanup of Company-owned or operated sites due to state regulations revised in 1993. The potential hazardous waste liabilities are further described in the *Environmental* section of Item 7.

The Company currently disposes of low-level radioactive waste (LLW) generated at Pilgrim Station through arrangements with licensed disposal facilities located in Barnwell, South Carolina. As a result of developments which have occurred pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, the Company's continued access to such disposal facilities has become severely limited and significantly increased in cost. See Note D to the consolidated financial statements in Item 8 for further discussion regarding LLW disposal.

The Company's existing fuel storage facility at Pilgrim Station includes sufficient room for spent nuclear fuel generated through early 1995. A request for a license amendment to allow modification of the storage facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012 is pending before the Nuclear Regulatory Commission (NRC). The Company expects approval of the request in 1994. At that time the Company will initially modify the facility to provide spent fuel storage capacity through approximately 2003. In addition, the United States Department of Energy (DOE), which is ultimately responsible for the disposal of spent nuclear fuel as required by the Nuclear Waste Policy Act of 1982, is currently conducting scientific studies evaluating a potential spent nuclear fuel repository site at Yucca Mountain, Nevada. The potential site, however, has encountered substantial public and political opposition and litigation and the DOE has publicly stated that it may be unable to construct such a repository in a timely manner. The Company is unable to predict whether and on what schedule the DOE will eventually construct a repository and what the effect will be on the Company.

Published reports have discussed the possibility that adverse health effects may be caused by electromagnetic fields associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. This topic is discussed more fully in the *Environmental* section of Item 7.

Number of Employees

The Company had 4,404 full-time and 14 part-time employees as of the end of 1993, 2,775 of which are represented by two locals of the Utility Workers Union of America, AFL-CIO. The current four-year labor contract in effect with the locals is scheduled to expire in May 1994. Labor contract negotiations began in early February 1994 and the Company anticipates favorable resolution of these negotiations.

(d) Financial Information about Foreign and Domestic Operations and Export Sales

See *Principal Products and Services* for information regarding the geographical area served by the Company and revenues by class for the last three years.

(e) Additional Information

Regulation

The Company and its wholly-owned subsidiary, Harbor Electric Energy Company (HEEC), operate primarily under the authority of the DPU, whose jurisdiction includes supervision over retail rates for electricity, financing, investing and accounting. In addition, the Federal Energy Regulatory Commission (FERC) has jurisdiction over various phases of the Company's business including rates for power sold at wholesale for resale, facilities used for the transmission or sale of such power, certain issuances of short-term debt and regulation of the system of accounts. The Company's subsidiary BETG and its subsidiaries are not subject to such regulation.

Recent requirements imposed on the Company by the DPU are discussed under *Competitive Conditions* of this item and Non-Utility Generator Purchase Contracts in Item 2.

The Company is required to submit to the DPU annual performance standards applicable to its generating units and other units from which the Company purchases power under long-term contracts. The Company provides quarterly generating unit performance progress reports to the DPU. The DPU has the right to reduce subsequent fuel clause billings if it finds that the Company has been unreasonable or imprudent in the operation of its generating units or in the procurement of fuel.

In 1993 the Company received a generating unit performance order from the DPU for the performance period November 1990 through October 1991. The order required the Company to make refunds to its customers due to its not meeting certain performance standards. A subsequent order was received from the DPU in February 1994 for the performance period November 1991 through October 1992. The Company is currently assessing the potential customer refunds associated with missed performance goals. The Company has not yet received an order from the DPU for the performance period November 1992 through October 1993. The Company believes that its current provision for refunds will be sufficient to cover all potential refunds.

The NRC has broad jurisdiction over the siting, construction and operation of nuclear reactors with respect to public health and safety, environmental matters and antitrust considerations. A license granted by the NRC may be revoked, suspended or modified for failure to construct or operate a facility in accordance with its terms. The Company currently holds an operating license for Pilgrim Station which was issued in 1972 and expires in 2012.

Continuing NRC review of existing regulations and certain operating occurrences at other nuclear plants have periodically resulted in the imposition of additional requirements for all domestic nuclear plants, including Pilgrim Station. NRC inspections and investigations may result in the issuance of notices of violation. These notices may be accompanied by orders directing that certain actions be taken or by the imposition of monetary civil penalties. In addition, the Company might undertake certain actions in regard to Pilgrim Station at the request or suggestion of its insurers or the Institute of Nuclear Power Operations (INPO), a voluntary association of nuclear utilities dedicated to the promotion of safety and reliability in the operation of nuclear power plants.

Nuclear power continues to be a subject of political controversy and public debate manifested from time to time in the form of requests for various kinds of federal, state and local legislative or regulatory action, direct voter initiatives or referenda or litigation. The Company cannot predict the extent, cost or timing of any modifications to Pilgrim Station which might be required in the future as a result of additional regulatory or other requirements nor can it determine the effect of such future requirements on the continued operation of Pilgrim Station. The Company continues to evaluate the operation of the station from the standpoint of safety, reliability and economics and believes that such continued operation is in the best interests of the Company and its customers.

Capital Expenditures and Financings

The Company's most recent estimate of capital expenditures, allowance for funds used during construction (AFUDC), long-term debt maturities and sinking fund requirements for the years 1994 through 1998 are as follows:

(in thousands)	1994	1995	1996	1997	1998
Capital expenditures (1)	$201,000	$206,000	$184,000	$181,000	$172,000
AFUDC (2)	6,000	4,000	4,000	5,000	5,000
Long-term debt	-	100,600	101,600	101,600	101,600
Preferred stock sinking fund	2,000	2,000	2,000	2,000	2,000

(1) Excludes estimated nuclear fuel expenditures of $19,000, $9,000, $23,000, $12,000 and $25,000, respectively and capitalized DSM expenditures.

(2) Excludes estimated AFUDC on nuclear fuel of approximately $1,000 per year. The estimated AFUDC rate varies from 4.0% to 6.5%.

The Company conducts a continuing review of its capital expenditure and financing programs. These programs and the estimates shown above are therefore subject to revision due to changes in environmental standards, regulatory requirements, availability and cost of capital, interest rates and other assumptions. In addition, depending upon the outcome of certain air quality modeling studies, the Company may be required to make additional expenditures by 1999 in order to comply with the provisions of the 1990 Clean Air Act Amendments. The extent of any additional expenditures is uncertain at this time.

Capital expenditures in 1993 were approximately $247 million and consisted primarily of additions to the Company's transmission and distribution systems and fossil and nuclear generation facilities. Significant projects included spending for transmission and distribution of approximately $13 million for the replacement of electric system property, $9 million for a new substation and $7 million for a new energy control system. Capital spending for fossil generation facilities included approximately $24 million for environmental modifications at New Boston Station as described in the *Environmental* section of Other Matters in Item 7. Expenditures in 1993 for Pilgrim Station included approximately $32 million to improve efficiencies and meet regulatory requirements and $8 million for a new administrative building. Funds generated internally represented approximately 74%, 90% and 89% of capital expenditures in 1993, 1992 and 1991, respectively. It is expected that a significant portion of future capital expenditures will be funded internally.

The Company intends to continue spending significant amounts on its DSM programs. The Company spent approximately $53 million on these programs in 1993, of which $37 million was capitalized and is being collected from customers over six years in accordance with the Company's 1992 settlement agreement. See the Liquidity and Outlook for the Future sections in Item 7 for further discussion regarding the Company's DSM programs.

In 1993 the DPU approved a financing plan allowing the Company to issue up to $1.1 billion in securities through 1994 and to use the proceeds to refinance long-term securities and short-term debt. See Note F to the consolidated financial statements in Item 8 for specific information relating to the Company's financing activities.

Item 2. Properties and Power Supply

Company-Owned Facilities

The Company's total installed electric generation capacity as of December 31, 1993 is as follows:

Unit	Location	Installed Capacity (MW)	Type	Year Installed
Pilgrim Nuclear Power Station	Plymouth, MA	678	Nuclear	1972
New Boston Station Units 1 and 2	South Boston, MA	718	Fossil	1965-1967
Mystic Station	Everett, MA			
Units 4-5-6		469	Fossil	1957-1961
Unit 7		617	Fossil	1975
Combustion turbine generators (ten)	Various	239	Fossil	1966-1971

All of the Company's steam fossil fuel-fired electric generating units are located at tide water and have access to fuel oil storage and/or natural gas or oil pipelines from nearby suppliers.

The Company is also a 5.888% joint owner in W.F. Wyman Unit 4. The 619 MW oil-fired unit located in Yarmouth, Maine began operations in 1978 and is operated by Central Maine Power Company.

Additional electric generation capacity is available to the Company through its contractual arrangements with other utilities and non-utilities and its participation in the New England Power Pool as further described in this item.

As of December 31, 1993 the Company's transmission system was comprised of approximately 362 miles of overhead circuits operating at 115,000, 230,000 and 345,000 volts and approximately 155 miles of underground circuits operating at 115,000 and 345,000 volts. The substations supported by these lines consist of 42 transmission or combined transmission and distribution substations with transformer capacity of 10,025 megavolt amperes (MVA), 71 distribution substations with transformer capacity of 1,238 MVA and 18 primary network units with 88 MVA capacity. In addition, high tension service was delivered to 231 customers' substations. The overhead distribution system covers approximately 4,652 miles of streets and the underground distribution system extends through approximately 892 miles of streets. HEEC, the

Company's regulated subsidiary, has a distribution system that consists principally of a 4.09 mile 115Kv submarine distribution line and a temporary substation which is located on Deer Island in Boston, Massachusetts.

The Company's significant items of property consist of electric generating stations, substations and certain service centers and are generally located on Company-owned land, with certain exceptions as set forth in the Company's First Mortgage Bond Indenture and its supplements. The Company's high-tension transmission lines are generally located on land either owned by the Company or subject to easements in its favor. The Company's low-tension distribution lines and fossil fuel pipelines are located principally on public property under permission granted by local or state authorities.

The Massachusetts Energy Facilities Siting Board (EFSB) must approve Company plans for the construction of certain new generation or transmission facilities based upon findings that such facilities are consistent with state public health, environmental protection and resource use and development policies. The Company currently has no proceedings before the EFSB.

Long-Term Power Contracts

Refer to Note K to the consolidated financial statements in Item 8 for further information regarding the following contracts. The Company also has short-term agreements with several other utilities for varying periods for purchases of system and unit power, for sales of Company system and unit power and for transmission services.

Utility Purchase Contracts:

The Company has a contract with a subsidiary of Commonwealth Energy System and two other utilities in which the participants are sharing in equal amounts the output of an oil-fired electric generation plant. The Company is obligated to pay 25% of the unit's fixed and operating costs plus an annual return over a period of approximately 33 years for its proportionate share of generation.

The Company has two long-term purchased power contracts with the Massachusetts Bay Transit Authority (MBTA) for the availability of two of the MBTA's jet turbines. The MBTA retains the right to utilize the jets for its own emergency use and for testing purposes but the Company retains New England Power Pool credit for their capacity and output.

The Company owns 9.5% of the common stock of Connecticut Yankee Atomic Power Company, which operates a nuclear generating unit. The Company is entitled to receive 9.5% of the unit's output and is obligated to pay Connecticut Yankee 9.5% of its fixed and operating costs plus an annual return on investment.

Non-Utility Generator Purchase Contracts:

The Company currently purchases approximately 500 MW of capacity and associated energy from non-utility generators. A majority of these purchases are from Ocean State Power and Northeast Energy Associates. In 1993 the L'Energia facility located in Lowell, Massachusetts was declared commercial and the Company began purchasing electricity from this unit under a twenty-year agreement. In addition, the Company is purchasing power from two small hydro facilities, and began purchasing capacity and energy from the MassPower facility located in Springfield, Massachusetts in January 1994.

In June 1993 the DPU ordered the Company to purchase 132 MW of power from Altresco Lynn, LP, an independent power producer, starting as early as 1995. The Company opposes this order since it does not believe it needs any new power for several years. In July 1993 the Company asked the Massachusetts Supreme Judicial Court to reverse the order. The Court has not yet ruled on the Company's request. The Company has supported an appeal filed by other interested parties of the Energy Facilities Siting Board's conditional approval of Altresco Lynn's project. In February 1994 Altresco Lynn alleged that the Company's actions in opposing the project were improper and that it may seek to hold the Company responsible for any resulting damages.

Sales Contracts:

The Company has agreements with Montaup Electric Company, a subsidiary of Eastern Utilities Associates, and with Commonwealth Electric Company, a subsidiary of Commonwealth Energy System, under which Montaup and Commonwealth each purchase 11% of the capacity and corresponding energy of Pilgrim Station and pay 11% of the unit's fixed and operating costs plus an annual return. Montaup and Commonwealth have also agreed to indemnify the Company to the extent of 11% each of all loss, liability or damage not covered by insurance resulting from the operation, condemnation, shutdown or retirement of the unit. In addition, the Company has similar agreements with multiple municipal electric companies for a total of 3.7% of the capacity and corresponding energy of Pilgrim Station.

New England Power Pool

The Company is a member of the New England Power Pool (NEPOOL), a voluntary association of electric utilities in New England responsible for the coordination, monitoring and directing of the operations of the major generating and transmission facilities in the region. To assume maximum benefits of power pooling, the electric facilities of all member companies are operated by NEPOOL as if they were a single power system. This is accomplished through the use of a central dispatching system that uses the lowest cost generating and transmission equipment available at any given time. This operation is the responsibility of NEPOOL's central dispatch center, the New England Power Exchange (NEPEX). As a result of its participation in NEPOOL, the Company's operating revenues and costs are affected to some extent by the operations of the other members.

The table below sets forth certain information as of the date of the Company's 1993 summer and 1993-1994 winter peak loads:

	January 19, 1994 (Winter 1993-94)	July 7, 1993 (Summer 1993)
NEPEX utilities installed capacity:		
Seasonal maximum rating	25,529 MW	24,368 MW
Seasonal normal rating	25,232 MW	24,160 MW
NEPEX peak load (estimate)	19,422 MW	19,570 MW
Company territory peak load	2,474 MW	2,662 MW

The Company's net capacity was 3,663 MW at its summer peak and 3,533 MW at is winter peak. Its corresponding NEPOOL capacity obligations were estimated to be 3,190 MW and 3,289 MW, respectively.

In 1983 the NEPOOL participants signed an agreement, known as Phase I, with Hydro-Quebec of Canada to provide up to three million MWH of hydro-electric power annually to NEPOOL from 1986-1997. In 1985 a second agreement, known as Phase II, was made between NEPOOL and Hydro-Quebec to provide an additional seven million MWH of hydro-electric power annually for ten years. This agreement required expansion of the existing 690 MW Phase I interconnection. The Company and other New England electric utilities entered into an agreement to expand the interconnection with the Hydro-Quebec system of Canada to 2,000 MW.

The Phase II facilities began full commercial operation up to the 2,000 MW level in July 1991. The price of this energy is based on the average cost of fossil fuel in New England for the previous year. The contract price for the first five years is 80% of that average, and for the second five years will be 95% of that average. The Company receives capacity credit through NEPOOL for approximately 11% of the generation equivalent of the total Hydro-Quebec interconnection.

The Company has an approximately 11% equity ownership interest in the two companies which constructed the Phase II facilities. All equity participants are required to guarantee, in addition to their own share, the total obligations of those participants not meeting certain credit criteria. Amounts so guaranteed by the Company were approximately $22 million at December 31, 1993.

As a result of the continuing additions to New England generating capacity and minimally increasing energy requirements, the dispatching of Company-owned generating facilities by NEPEX may be affected.

Item 3. Legal Proceedings

In March 1991 the Company was named in a lawsuit brought in the United States District Court for the District of Massachusetts alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by the Company's 1988 reduction in force. Legal counsel is vigorously defending this case. Based on the information presently available, the Company does not expect that this litigation will have a material impact on the Company's financial condition. However, an unfavorable decision ordered against the Company could have a material impact on quarterly earnings.

See also Item 1, *Environmental Matters* and Note H to the consolidated financial statements in Item 8 for a discussion of legal issues involving hazardous waste sites.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the fourth quarter of 1993.

Executive Officers of the Registrant

The names, ages, positions and business experience during the last five years of all the executive officers of Boston Edison Company and its subsidiaries as of March 1, 1994 are listed below. There are no family relationships between any of the officers of the Company, nor any arrangement or understanding between any Company officer and another person pursuant to which the officer was elected. Officers of the Company hold office until the first meeting of the directors following the next annual meeting of the stockholders and until their respective successors are chosen and qualified.

Name, Age and Position	Business Experience During Past Five Years
Bernard W. Reznicek, 57 Chairman of the Board and Chief Executive Officer	Chairman of the Board and Chief Executive Officer (since 1993), formerly Chairman, President and Chief Executive Officer (1992-1993), President and Chief Executive Officer (1990-1992) and President and Chief Operating Officer (1987-1990). Director (since 1987). Chairman of the Board, Chief Executive Officer and Director, Harbor Electric Energy Company, Boston Energy Technology Group, TravElectric Services Corp. and Ener-G-Vision, Inc.
Thomas J. May, 46 President and Chief Operating Officer	President and Chief Operating Officer (since 1993), formerly Executive Vice President (1990-1993) and Senior Vice President (1987-1990). Director (since 1991). President, Chief Operating Officer and Director, Harbor Electric Energy Company; President and Director, Boston Energy Technology Group; Director, TravElectric Services Corp., Ener-G-Vision, Inc. and REZ-TEK International Corp.

Name, Age and Position	Business Experience During Past Five Years
George W. Davis, 60 Executive Vice President	Executive Vice President (since 1992), responsible for all power supply and delivery operations. Director (since 1991). Senior Vice President - Nuclear (1990-1992). Vice President - Nuclear Administration (1989-1990).
E. Thomas Boulette, 51 Senior Vice President - Nuclear	Senior Vice President - Nuclear (since 1993). Vice President - Nuclear Operations and Station Director (1992-1993). Vice President - Operations (1989-1992) and Plant Manager (1988-1989) of Maine Yankee Atomic Power Company.
Cameron H. Daley, 48 Senior Vice President - Power Supply	Senior Vice President - Power Supply (since 1989). Vice President - Power Production (1982-1989).
John J. Desmond, III, 60 Senior Vice President - Legal	Senior Vice President - Legal (since 1992). Vice President and General Counsel (1985-1992).
L. Carl Gustin, 50 Senior Vice President - Marketing & Corporate Relations	Senior Vice President - Marketing & Corporate Relations (since 1989). Vice President - Corporate Relations (1986-1989).
John J. Higgins, Jr., 61 Senior Vice President - Human Resources	Senior Vice President - Human Resources (since 1990). Vice President - Human Resources (1988-1990).
Ronald A. Ledgett, 55 Senior Vice President - Power Delivery	Senior Vice President - Power Delivery (since 1991). Director, Special Projects (1989-1991).

Name, Age and Position	Business Experience During Past Five Years
Charles E. Peters, Jr., 42 Senior Vice President - Finance	Senior Vice President - Finance (since 1991). Chief Financial Officer and Senior Vice President of Genrad, Inc. (1985-1991). Vice President, Treasurer and Director, Harbor Electric Energy Company; Treasurer and Director, Boston Energy Technology Group; Director, TravElectric Services Corp., Ener-G-Vision, Inc. and REZ-TEK International Corp.
Marc S. Alpert, 49 Vice President and Treasurer	Vice President and Treasurer (since 1988). Assistant Treasurer, Harbor Electric Energy Company and Boston Energy Technology Group.
Robert J. Weafer, Jr., 47 Vice President, Controller and Chief Accounting Officer	Vice President, Controller and Chief Accounting Officer (since 1991). Controller and Chief Accounting Officer (1988-1991).
Theodora S. Convisser, 46 Clerk of the Corporation	Clerk of the Corporation (since 1986). Clerk of Harbor Electric Energy Company, Boston Energy Technology Group, TravElectric Services Corp., Ener-G-Vision, Inc. and REZ-TEK International Corp.

Part II

Item 5. Market for the Registrant's Common Stock and Related Stockholder Matters

(a) Market Information

The Company's common stock is listed on the New York and Boston Stock Exchanges.

Following are the reported high and low sales prices of the Company's common stock on the New York Stock Exchange as reported daily in the *Wall Street Journal* for each of the quarters in 1993 and 1992:

	1993		1992	
	High	Low	High	Low
First quarter	$30 1/2	$26 3/8	$24 5/8	$22 1/8
Second quarter	30 7/8	27 7/8	26	22 3/8
Third quarter	32 5/8	29 3/4	26 7/8	24 7/8
Fourth quarter	32 1/4	27 7/8	28 1/4	24 3/4

(b) Holders

As of December 31, 1993, the Company had 42,392 holders of record of its common stock (actual count of record holders).

(c) Dividends

Following are the dividends declared per share of common stock for each of the quarters in 1993 and 1992:

	1993	1992
First quarter	$0.425	$0.410
Second quarter	0.425	0.410
Third quarter	0.425	0.410
Fourth quarter	0.440	0.425

Item 6. Selected Financial Data

The following table summarizes five years of selected consolidated financial data of the Company (in thousands, except per share data).

	1993	1992	1991	1990	1989
Operating revenues	$1,482,253	$1,411,753	$1,354,501	$1,314,440	$1,339,956
Net income/ (loss)	118,218	107,298	94,670	79,616(a)	(16,135)(b)
Earnings/(loss) per common share	2.28	2.10	1.96	1.60(a)	(0.88)(b)
Total assets	3,477,299	3,294,234	3,119,285	3,012,589	2,876,691
Long-term debt	1,272,497	1,091,073	1,136,765	1,074,025	948,839
Redeemable preferred/ preference stock	221,000	221,000	221,333	221,333	221,333
Cash dividends declared per common share	1.715	1.655	1.595	1.535	1.745

(a) Before cumulative effect of change in accounting principle ($15,824 or $0.41 per common share).

(b) Includes $106,280 or $2.78 per common share loss applicable to rate and contract settlements.

Item 7. Management's Discussion and Analysis

Regulatory Proceedings

Retail settlement agreements

Effective November 1992 our state regulators, the Massachusetts Department of Public Utilities, approved a three-year settlement agreement. This agreement provides us with retail rate increases, allows for the recovery of demand side management (DSM) conservation program expenditures, specifies certain accounting adjustments and clarifies the timing and recognition of certain expenses. The agreement also sets a limit on our rate of return on common equity of 11.75% for 1993 through 1995, excluding any penalties or rewards from performance incentives.

The retail rate increases consist of a new annual performance adjustment charge effective November 1992 and two additional rate increases of $29 million effective November 1993 and November 1994. The performance adjustment charge varies annually based upon the performance of our Pilgrim Nuclear Power Station. This charge is further described in our discussion of financial condition.

Our 1993 results of operations were affected by the recovery of DSM program expenditures, accounting adjustments and timing and recognition of certain expenses as further described in the following Results of Operations section.

Our state regulators approved a previous three-year settlement agreement effective November 1989. That agreement also provided us with retail rate increases and specified certain accounting adjustments. The 1989 agreement primarily affected our results of operations through 1992.

Results of Operations

1993 Versus 1992

Earnings per common share were $2.28 in 1993 and $2.10 in 1992. The increase in earnings is primarily the result of an annual rate increase effective November 1992, lower purchased power expense due to a long-term contract expiration, no amortization of deferred cancelled nuclear unit costs and lower interest expense. These positive changes were partially offset by higher operations and maintenance expense and higher income tax and property tax expenses.

Operating revenues

Operating revenues increased 5% over 1992 as follows:

(in thousands)	
Retail electric revenues	$70,837
Demand side management revenues	33,601
Wholesale and other revenues	(2,794)
Short-term sales revenues	(31,144)
Increase in operating revenues	$70,500

Retail electric revenues increased $70.8 million. The November 1992 and 1993 rate increases resulted in $40.6 million of additional revenues in 1993. Fuel and purchased power revenues increased $29.5 million over 1992, partly due to lower revenues received from short-term power sales as discussed below.

We began recovery of certain demand side management program costs, lost base revenues and incentives in August 1992. Our 1993 revenues provided $45.9 million related to 1991, 1992 and 1993 DSM programs. Our 1992 revenues of $12.3 million related primarily to 1991 programs.

The decrease in wholesale and other revenues reflects an estimated provision for refunds to customers of approximately $8 million as a result of orders from our state regulators on our generating unit performance program.

Lower short-term power sales revenues were a result of changes in our generation availability and the needs of short-term power purchasers. All revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and have no effect on earnings.

Operating expenses

Fuel expense decreased $19.5 million primarily due to a 21.5% decrease in generation, resulting from planned overhauls of our fossil plants. Interchange purchases increased due to the lower generation, resulting in a $7.5 million net increase in purchased power expense. The net increase also reflects savings of approximately $10 million from a long-term purchased power contract that expired in October 1993. Both our fuel and purchased power expenses are substantially fully recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 7.1% primarily due to increases in employee benefits and nuclear production expenses. Postretirement benefits expense increased by $7 million primarily as a result of the adoption of a new accounting standard and pension expense increased by $5 million; both are provided for in our 1992 settlement agreement and further explained in Note I to the consolidated financial statements. A refueling outage at Pilgrim Station in 1993 resulted in higher nuclear production expenses.

Depreciation and amortization expense increased in 1993 primarily due to a higher annual decommissioning charge for Pilgrim Station effective November 1992 provided by the 1992 settlement agreement. The new charge is based on a 1991 estimate of decommissioning costs as further discussed in Note D to the consolidated financial statements. In addition, the effect of lower depreciation rates implemented in accordance with the settlement agreement was offset by the effect of a higher depreciable plant balance.

In accordance with our 1992 settlement agreement we did not expense any of the $19 million of remaining deferred costs associated with the cancelled Pilgrim 2 nuclear unit in 1993. We will expense the remaining costs in 1994 and/or 1995.

Amortization of deferred nuclear outage costs includes amounts related to the 1993 and 1991 refueling outages at Pilgrim Station. In 1993 we deferred approximately $14 million of refueling outage costs. We began to amortize these costs in June 1993 over five years as approved in the 1992 settlement agreement.

The increase in demand side management programs expense is consistent with the increase in DSM revenues. DSM expense includes some costs recovered over a twelve month period and other costs recovered over six years. We began to recover previously deferred DSM expenses in August 1992. In 1993 we expensed and collected from customers approximately $30 million of deferred 1991, 1992 and 1993 program costs. Over six years we are expensing and collecting from our customers $11 million of costs capitalized in 1992 and $37 million of costs capitalized in 1993. The 1993 expense related to these capitalized costs was $7 million.

Municipal property and other taxes increased in 1993 due to the absence of tax abatements. In 1992 property taxes were reduced by $10.4 million of tax abatements in accordance with our 1989 settlement agreement.

Our effective annual income tax rate for 1993 was 23.4% vs. 8.7% for 1992. Both rates were significantly reduced by adjustments to deferred income taxes of $20 million in 1993 and $23 million in 1992 made in accordance with the 1992 and 1989 settlement agreements. The 1992 rate was also reduced due to tax benefits of approximately $7 million resulting from mandated payments made in accordance with the 1989 agreement. Our adoption of a new accounting standard for income taxes in 1993 did not significantly affect earnings. We expect our effective tax rate to be close to the statutory rate in 1994.

Interest charges and preferred and preference dividends

Total interest charges decreased $3.8 million in 1993. Interest on long-term debt decreased primarily due to the refinancing of substantially all our first mortgage bonds in 1993 at lower interest rates, partially offset by higher amortization of redemption premiums. Other interest charges decreased due to a lower short-term debt level and lower short-term interest rates. Allowance for funds used during construction (AFUDC), which represents the financing costs of construction, decreased as a result of a lower AFUDC rate related to lower short-term interest rates.

Preferred and preference dividends decreased 5% due to the replacement of a preferred and a preference stock issue with less costly issues of preferred stock.

1992 Versus 1991

Earnings per common share were $2.10 in 1992 and $1.96 in 1991. The increase in earnings is primarily the result of a rate increase effective November 1991, incentive revenues earned from the performance of Pilgrim Station and lower income tax and interest expenses. These increases were partially offset by higher operations and maintenance and property tax expenses. We also had a one-time charge in 1992 for costs incurred for a deferred generating plant project.

Operating revenues

Operating revenues increased 4.2% over 1991 as follows:

(in thousands)	
Retail electric revenues	$27,672
Demand side management revenues	12,343
Wholesale and other revenues	1,881
Short-term sales revenues	15,356
Increase in operating revenues	$57,252

Retail electric revenues increased $27.7 million. We received a $25 million rate increase effective November 1991 as part of the 1989 settlement agreement. We also earned $8.2 million in incentive revenues in 1992 as a result of Pilgrim Station's capacity factor exceeding its target set in the agreement. Fuel and purchased power revenues decreased approximately $5 million due to higher purchased power costs more than offset by higher revenues received from short-term power sales as discussed below.

In 1992 we began to receive revenues for the recovery of certain DSM program costs, lost base revenues and incentives. The 1992 revenues relate primarily to 1991 DSM programs.

Our short-term power sales increased in 1992 as a result of our high generating unit availability and the greater power needs of other New England utilities. All revenues from short-term sales served to reduce fuel and purchased power billings to retail customers and had no effect on earnings.

Operating expenses

Purchased power expense increased $18 million in 1992 due to new long-term purchased power contracts. Both our fuel and purchased power expenses are substantially fully recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 2.3% due primarily to increases in employee benefit expenses and bad debts.

Amortization of deferred nuclear outage costs in 1992 and 1991 includes amounts primarily related to the 1991 refueling outage at Pilgrim Station. In 1991 we deferred approximately $23 million of refueling outage costs. We began to expense these costs over five years in September 1991 as approved by our state regulators.

Municipal property and other taxes increased 21% primarily due to a reduction in residential and commercial real estate values caused by the depressed economy. This resulted in higher tax rates applied to our personal property values. In accordance with our 1989 settlement agreement, municipal property tax expenses were reduced by tax abatements of $10.4 million in 1992 and $13.6 million in 1991.

Our effective annual income tax rate for 1992 was 8.7% vs. 16.5% for 1991. Both rates were significantly reduced by adjustments to deferred income taxes of $23 million in 1992 and $13 million in 1991 made in accordance with the 1989 settlement agreement. We also received tax benefits in both years as a result of payments mandated by the agreement.

Other income and expense

In 1992 we expensed $8 million of costs previously invested in the proposed Edgar Energy Park generation project. This project was deferred indefinitely as additional generating capacity is not expected to be needed for several years.

Interest charges and preferred and preference dividends

Total interest charges decreased 4.6% primarily due to lower interest rates on our average short-term borrowings. AFUDC decreased 12.7% due to a lower AFUDC rate related to lower short-term interest rates.

Preferred and preference dividends decreased approximately $1 million primarily due to the replacement of two preference stock series with less costly issues of preferred stock.

Earnings per share

Net income increased 13%. However, earnings per common share for 1992 increased only 7%, reflecting an increase in the weighted average number of common shares outstanding primarily a result of our 1991 and 1992 common stock issuances.

Financial Condition

Our 1992 settlement agreement provides us with increased revenues from retail customers over the three-year period ending October 1995. Additionally, a long-term purchased power contract with annual charges of approximately $60 million expired in October 1993 with no related change in revenues. We are limited to an annual rate of return on equity during the three-year period of 11.75%, excluding any penalties or rewards from performance incentives.

Our continued ability to achieve or exceed the 11.75% rate of return on equity will be primarily dependent upon our ability to control costs and to earn performance incentives from generation performance mechanisms specified in both the 1989 and 1992 settlement agreements. The most significant impact that incentives can have on our financial results is based on Pilgrim Station's annual capacity factor. Effective November 1993 an annual capacity factor between 60% and 68% will provide us with approximately $45 million of revenues through the performance adjustment charge. For each percentage point increase in capacity factor above 68%, annual revenues will increase by $670,000. For each percentage point decrease in capacity factor below 60% (to a minimum of 35%) annual revenues will decrease by $770,000. Pilgrim's capacity factor for the performance year ending October 1994 is expected to be approximately 81% (assuming normal operating conditions), an increase over the 66% capacity factor achieved in the performance year ended October 1993, as no refueling outage is scheduled for 1994. We earned approximately $40 million in performance charge revenues in the performance year ended October 1993.

Our fossil generation unit performance can provide an increase or decrease of up to $4 million in revenues in each performance year, however, we do not expect any revenue adjustments from this mechanism.

Liquidity

We meet our plant expenditure cash requirements primarily with internally generated funds. These funds (excluding payments made related to settlement agreements) provided for 74%, 90% and 89% of our plant expenditures in 1993, 1992 and 1991, respectively. Our current estimate of plant expenditures for 1994 is $233 million, including $20 million of nuclear fuel additions. These expenditures will be used primarily to maintain and improve existing transmission, distribution and generation facilities. We also estimate capitalizable DSM expenditures to be $38 million in 1994, which will be collected from customers over six years. We do not expect plant expenditures, excluding nuclear fuel and DSM, to vary significantly from the 1994 amount in the four years thereafter. We have long-term debt and preferred stock payment requirements of $2 million in 1994, $102.6 million in 1995, and $103.6 million per year in 1996 through 1998.

External financings continue to be necessary to supplement our internally generated funds, primarily the issuance of short-term commercial paper and bank borrowings. We currently have authority from our federal regulators to issue up to $350 million of short-term debt. We have a $200 million revolving credit agreement and arrangements with several banks to provide additional short-term credit on a committed as well as on an uncommitted and as available basis. At December 31, 1993 we had $204.1 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. In 1993 our state regulators approved a financing plan allowing us to issue up to $1.1 billion in securities through 1994 and to use the proceeds to refinance long-term securities and short-term debt. At December 31, 1993 we had $245 million remaining authorized to be issued under the plan which can be used to issue common stock, preferred stock and long-term debt. As a result of our refinancing activities in 1993 we expect to realize annualized savings of approximately $11.5 million. Refer to Note F to the consolidated financial statements for specific information relating to our recent financing activities.

Outlook for the Future

Electricity sales

A significant portion of our electricity sales are made to commercial customers rather than industrial customers. As a result our sales have been only moderately impacted by the decline in the local Massachusetts economy. Our retail sales increased 1.2% in 1993 and we anticipate only slight growth in retail sales in the near term.

Implementation of DSM programs, which are designed to assist customers in reducing electricity use, will result in lower growth in electricity sales. The 1992 settlement agreement established annual DSM spending levels over $50 million through 1994. The agreement provides for collection from customers of certain costs primarily in the year incurred and others over a six-year period. We are also provided with incentives and recovery of lost revenues based on the actual reduction in customer electricity usage from these programs and a return on the costs that we recover over six years.

Competition

As we are operating in a time of increasing competition from other electric utilities and non-utility generators to sell electricity for resale, we have secured long-term power supply agreements with our four wholesale customers. Through these agreements our rates are set principally through the year 2002. We also obtained a new wholesale customer in 1993 for which we will provide up to 30 megawatts of contract demand power for ten years beginning November 1994.

Our state regulators require utilities to purchase power from qualifying non-utility generators at prices set through a bidding process. In June 1993 our state regulators ordered us to purchase 132 megawatts of power from an independent power producer, starting as early as 1995. We oppose this order since we do not believe we need any new power for several years. In July 1993 we asked the Massachusetts Supreme Judicial Court to reverse the order. We are currently awaiting a decision from the court. In addition, our state regulators have created an integrated resource management (IRM) process in which electric utilities forecast their future energy needs and propose how they will meet those needs by balancing conservation programs with all other supplies of energy. We will submit an IRM filing in March 1994.

Direct competition with other electric utilities for retail electricity sales is still subject to substantial limitations, but these limitations may be reduced in the future. In 1993 we announced our goal of not seeking additional rate increases, other than those provided in the 1992 settlement agreement, for our residential, commercial and industrial customers until at least the year 2000. We plan to accomplish this by controlling costs and increasing operating efficiencies without sacrificing quality of service or profitability. The announcement reflects our strong commitment to be a competitively priced reliable provider of energy.

Non-utility business

In 1993 we created an unregulated subsidiary known as the Boston Energy Technology Group (BETG) following approval from our state regulators. We have authority to invest up to $45 million in this wholly-owned subsidiary over the next three years. BETG will engage in demand side management activities through its wholly-owned subsidiary Ener-G-Vision, Inc. and businesses involving electric transportation and the related infrastructure through its wholly-owned subsidiary TravElectric Services Corporation. We do not currently have a substantial investment in BETG and do not anticipate it significantly impacting our results of operations in the next several years.

In January 1994 BETG acquired a substantial majority interest in the assets of REZ-TEK International, Inc., a manufacturer of ozone water treatment systems. The new entity, which will be known as REZ-TEK International Corp., will continue the business of producing a system that treats cooling water used in commercial and industrial air conditioning systems in an energy efficient and environmentally sound manner.

Other Matters

Environmental

We are subject to numerous federal, state and local standards with respect to air and water quality, waste disposal and other environmental considerations. These standards can require that we modify our existing facilities or incur increased operating costs.

In 1991 we entered into a consent order with the Massachusetts Department of Environmental Protection (DEP) and other interested parties to undertake certain improvements in the emission control systems at New Boston Station. These improvements included the replacement of four existing chimney stacks with two taller stacks in order to improve the air quality in the vicinity of the station, and the installation of low nitrogen oxides burners. The capital cost of these modifications along with other associated improvements has been approximately $78 million through 1993 with an additional $3 million expected to complete these projects in 1994.

New Boston Station has the ability to burn natural gas, oil or both. As part of the DEP consent order we also agreed to operate the station using natural gas as fuel for a minimum of nine months per year beginning in April 1992. Beginning in April 1995 we will be required to operate the station fueled exclusively by natural gas, except in certain emergency circumstances. We have made arrangements for a nine month supply of natural gas to the station until April 1995 and are currently in the process of negotiating with natural gas suppliers and transporters concerning the economics and availability of natural gas to New Boston on a year-round basis after that time. Year-round gas supplies are currently not available to the station and, as a result, the outcome of our negotiations with natural gas suppliers and transporters and the impact on the operation of New Boston Station are uncertain.

The 1990 Clean Air Act Amendments will require a significant reduction in nationwide emissions of sulfur dioxide from fossil fuel-fired generating units. The reduction will be accomplished by restricting sulfur dioxide emissions through a market-based system of allowances. We believe that we will have allowances issued to us that are in excess of our needs and which may be marketable. Any gain from the sale of these may be subject to future regulatory treatment. Other provisions of the 1990 Clean Air Act Amendments involve limitations on emissions of nitrogen oxides from existing generating units. Combustion system modifications made to New Boston and Mystic Stations, including the installation of the low nitrogen oxides burners at New Boston, will allow the units to meet the provisions of the 1995 standards. Depending upon the outcome of certain air quality modeling studies, additional emission reductions may also be required by 1999. The extent of any additional reductions and the cost of any further modifications is uncertain at this time.

State regulations revised in 1993 require that properties where releases of hazardous materials occurred in the past be further cleaned up according to a timetable developed by the DEP. We are currently evaluating the potential costs associated with the cleanup of sites where we have been identified as the owner or operator. There are uncertainties associated with these potential costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of certain other multi-party hazardous waste sites in Massachusetts and other states. At the majority of these other sites we are one of many potentially responsible parties and our alleged share of the responsibility is a small percentage. We do not expect any of our potential cleanup liabilities to have a material impact on financial condition, although provisions for cleanup costs could have a material impact on quarterly earnings.

We presently dispose of low-level radioactive waste (LLW) generated at Pilgrim Station at licensed disposal facilities in Barnwell, South Carolina. As a result of developments which have occurred pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, our continued access to such disposal facilities has become severely limited and significantly increased in cost. Refer to Note D to the consolidated financial statements for further discussion regarding LLW disposal.

In recent years a number of published reports have discussed the possibility that adverse health effects may be caused by electromagnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Some scientific reviews conducted to date by several state and federal agencies have suggested assoc ations between EMF and such health effects, while other studies have not substantiated such associations. We support further research into the subject and are participating in the funding of industry sponsored studies. We are aware that public concern regarding EMF in some cases has resulted in litigation, in opposition to existing or proposed facilities before regulators, or in requests for legislation or regulatory standards concerning EMF levels. We have not been significantly affected to date by these developments and cannot predict their potential impact on us, however, we continue to closely monitor all aspects of the EMF issue.

Litigation

In March 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel is vigorously defending this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on quarterly earnings.

Labor negotiations

We began negotiations involving our labor contracts in early February 1994. These contracts expire on May 15, 1994. We anticipate favorable resolution of these negotiations prior to that date.

New accounting pronouncements

We will adopt Statement of Financial Accounting Standards (SFAS) No. 112, Employers' Accounting for Postemployment Benefits, and SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, in the first quarter of 1994. Refer to Notes I and J to the consolidated financial statements for further discussion of these pronouncements.

Item 8. Financial Statements and Supplementary Financial Information

Consolidated Statements of Income

(in thousands, except earnings per share)	1993	1992	1991
		years ended December 31,	
Operating revenues	$1,482,253	$1,411,753	$1,354,501
Operating expenses:			
Fuel	176,366	195,873	200,912
Purchased power	364,482	356,931	338,994
Other operations and maintenance	406,271	379,350	370,758
Depreciation and amortization	137,722	129,045	126,151
Amortization of deferred cost of cancelled nuclear unit	0	24,381	24,381
Amortization of deferred nuclear outage costs	6,546	4,901	2,443
Demand side management programs	37,504	8,221	1,674
Taxes - property and other	93,102	80,426	66,216
Income taxes	34,941	11,725	17,111
Total operating expenses	1,256,934	1,190,853	1,148,640
Operating income	225,319	220,900	205,861
Other income (expense), net	589	(2,074)	5,684
Operating and other income	225,908	218,826	211,545
Interest charges:			
Long-term debt	104,375	106,850	108,912
Other	9,778	12,525	16,947
Allowance for borrowed funds used during construction	(6,463)	(7,847)	(8,984)
Total interest charges	107,690	111,528	116,875
Net income	118,218	107,298	94,670
Preferred and preference dividends provided	15,705	16,550	17,611
Balance available for common stock	$ 102,513	$ 90,748	$ 77,059
Common shares outstanding (weighted average)	44,959	43,144	39,348
Earnings per share of common stock	$ 2.28	$ 2.10	$ 1.96

Consolidated Statements of Retained Earnings

(in thousands)	1993	1992	1991
		years ended December 31,	
Balance at beginning of year	$192,948	$174,477	$161,143
Net income	118,218	107,298	94,670
Subtotal	311,166	281,775	255,813
Cash dividends declared:			
Preferred stock	15,705	14,923	9,476
Preference stock	0	1,953	8,135
Common stock	77,169	71,951	63,725
Subtotal	92,874	88,827	81,336
Balance at end of year	$218,292	$192,948	$174,477

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

Consolidated Balance Sheets

(in thousands)		1993		December 31, 1992
Assets				
Property, plant and equipment, at original cost:				
Utility plant in service	$3,904,776		$3,629,727	
Less: accumulated depreciation	1,258,359	$2,646,417	1,177,294	$2,452,433
Nuclear fuel	273,867		270,420	
Less: accumulated amortization	220,477	53,390	201,978	68,442
Construction work in progress		144,835		182,458
Total		2,844,642		2,703,333
Investments in electric companies, at equity		24,292		25,398
Nuclear decommissioning fund, at cost		66,060		50,871
Current assets:				
Cash and cash equivalents	8,768		3,947	
Accounts receivable	171,098		185,563	
Accrued unbilled revenues	29,823		28,564	
Fuel, materials and supplies, at average cost	79,381		93,931	
Prepaid expenses and other	9,738	298,808	6,644	318,649
Deferred debits:				
Power contracts	36,275		43,717	
Cancelled nuclear unit	19,067		19,067	
Nuclear outage costs	25,524		17,970	
Pension and postretirement costs	24,416		10,449	
Redemption premiums	59,116		40,506	
Regulatory asset-income taxes, net	26,916		0	
Other	52,183	243,497	64,274	195,983
Total assets		$3,477,299		$3,294,234
Capitalization and Liabilities				
Common stock equity		$ 876,479		$ 840,312
Cumulative preferred stock:				
Non-mandatory redeemable series		123,000		123,000
Mandatory redeemable series		96,000		98,000
First mortgage bonds		40,000		631,825
Sewage facility revenue bonds, net		32,497		24,248
Debentures		1,200,000		385,000
Unsecured medium-term notes		0		50,000
Current liabilities:				
Long-term debt/preferred stock due within one year	$ 2,000		$ 6,800	
Notes payable	204,151		275,500	
Accounts payable	144,760		154,251	
Interest accrued	25,467		21,497	
Dividends payable	22,696		22,192	
Other	27,336	426,410	12,482	492,722
Deferred credits:				
Power contracts	36,275		43,717	
Accumulated deferred income taxes	484,796		448,720	
Accumulated deferred investment tax credits	71,140		75,213	
Nuclear decommissioning reserve	73,744		57,165	
Other	16,958	682,913	24,312	649,127
Commitments and contingencies		-		-
Total capitalization and liabilities		$3,477,299		$3,294,234

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

Consolidated Statements of Cash Flows

(in thousands)	1993	1992	1991
		years ended December 31,	
Cash flows from operating activities:			
Net income	$118,218	$107,298	$ 94,670
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	130,074	123,243	121,572
Amortization of nuclear fuel	21,816	25,473	19,869
Amortization of deferred cost of cancelled nuclear unit, net	0	22,340	21,112
Other amortization	9,433	2,132	1,696
Allowance for funds used during construction	(6,463)	(7,847)	(8,984)
Deferred income taxes	10,303	17,165	24,476
Investment tax credits	(4,073)	(4,273)	(4,290)
(Deferral) amortization of nuclear outage costs, net	(7,554)	4,901	(22,062)
Net changes in:			
Accounts receivable and accrued unbilled revenues	13,206	(18,188)	(3,519)
Fuel, materials and supplies	9,722	(2,330)	12,716
Accounts payable	(9,491)	41,899	(19,510)
Rate and contract settlements	(175)	(31,363)	(44,546)
Other current assets and liabilities	16,408	(2,565)	3,079
Other, net	(4,958)	(13,777)	(24,588)
Net cash provided by operating activities	296,466	264,108	171,691
Cash flows provided (used) by investing activities:			
Plant and nuclear fuel (excluding AFUDC)	(253,885)	(231,025)	(214,213)
Capitalized demand side management costs	(37,156)	(11,469)	0
Decommissioning fund	(15,189)	(7,210)	(5,896)
Investments in electric companies	1,106	1,836	(1,515)
Net cash used by investing activities	(305,124)	(247,868)	(221,624)
Cash flows provided (used) by financing activities:			
Issuances:			
Common stock	10,823	68,345	68,800
Preferred stock	40,000	40,000	50,000
Long-term debt	815,000	60,000	146,120
Redemptions:			
Debt retirements	(648,625)	(123,600)	(118,600)
Preferred/preference stock	(40,000)	(40,333)	(50,000)
Net change in short-term debt	(71,349)	65,200	35,770
Dividends paid	(92,370)	(86,184)	(79,545)
Net cash provided (used) by financing activities	13,479	(16,572)	52,545
Net increase (decrease) in cash and cash equivalents	4,821	(332)	2,612
Cash and cash equivalents at the beginning of the year	3,947	4,279	1,667
Cash and cash equivalents at the end of the year	$ 8,768	$ 3,947	$ 4,279
Cash paid during the year for:			
Interest, net of amounts capitalized	$103,720	$113,076	$115,488
Income taxes	$ 30,305	$ 10,095	$ 18,979

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

Notes to Consolidated Financial Statements

Note A. Significant Accounting Policies

1. Basis of Consolidation and Accounting

The consolidated financial statements include the activities of our wholly-owned subsidiaries, Harbor Electric Energy Company and Boston Energy Technology Group. All significant intercompany transactions have been eliminated.

We follow accounting policies prescribed by our federal and state regulators. We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The financial statements comply with generally accepted accounting principles. Certain prior period amounts on the financial statements were reclassified to conform with current presentation.

2. Revenue Recognition

We record revenues for electricity used by our customers, but not yet billed, in order to more closely match revenues with expenses

3. Forecasted Fuel and Purchased Power Rates

The rate charged to retail customers for fuel and purchased power allows for all fuel costs, the capacity portion of some purchased power costs and some transmission costs to be billed to customers monthly using a forecasted rate. The difference between actual and estimated costs is included in accounts receivable on our consolidated balance sheets until subsequent rates are adjusted. State regulators have the right to reduce our subsequent fuel rates if they find that we have been unreasonable or imprudent in the operation of our generating units or in purchasing fuel.

4. Depreciation and Nuclear Fuel Amortization

Our physical property was depreciated on a straight-line basis in 1993, 1992 and 1991 at composite rates of approximately 3.09%, 3.36% and 3.41% per year, respectively, based on estimated useful lives of the various classes of property. The cost of decommissioning Pilgrim Station, our nuclear unit, is excluded from the depreciation rates. When property units are retired, their cost, net of salvage value, is charged to accumulated depreciation.

The cost of nuclear fuel is amortized based on the amount of energy Pilgrim Station produces. Nuclear fuel expense also includes an amount for the estimated costs of ultimately disposing of the spent nuclear fuel and for the decontamination and decommissioning of the United States enrichment facilities used in the production of nuclear fuel. These costs are recovered from our customers through fuel charges.

5. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated costs to finance plant expenditures. In accordance with regulatory accounting, AFUDC is included as a cost of utility plant. AFUDC is not an item of current cash income, but payment is received for these costs from customers over the service life of the plant in the form of increased revenues collected as a result of higher depreciation expense. Our AFUDC rates in 1993, 1992 and 1991 were 3.62%, 4.48%, and 6.85%, respectively, and represented only the cost of debt.

6. Cash and Cash Equivalents

Cash and cash equivalents are comprised of highly liquid securities with maturities of three months or less.

7. Allowance for Doubtful Accounts

Our accounts receivable are substantially all recoverable. This recovery occurs both from customer payments and from the portion of customer charges that provides for the recovery of bad debt expense. Accordingly, we do not maintain a significant allowance for doubtful accounts balance.

8. Deferred Debits

Deferred debits consist primarily of costs incurred which will be collected from customers through future charges in accordance with agreements with our state regulators. These costs will be expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. A portion of these costs is currently being charged to and collected from customers.

9. Amortization of Discounts, Premiums and Redemption Premiums on Securities

We expense discounts, premiums, redemption premiums and related expenses associated with issuances of securities or refinancing of existing securities in equal annual installments over the life of the replacement securities subject to regulatory approval.

Note B. Retail Settlement Agreements

In 1992 and 1989 our state regulators, the Massachusetts Department of Public Utilities, approved three-year settlement agreements relating to our rate case proceedings. These agreements provided for retail rate increases, accounting adjustments and demand side management program expenditures; clarified the timing and recognition of certain expenses and set limits on our rate of return on common equity. Refer to Management's Discussion and Analysis for further information related to these settlement agreements.

The settlement agreements did not affect our contract or wholesale power rates charged to other utilities, which are regulated by our federal regulators, the Federal Energy Regulatory Commission.

Note C. Income Taxes

In the first quarter of 1993 we prospectively adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). This required us to change our methodology of accounting for income taxes from the deferred method to an asset and liability approach. The deferred method of accounting was based on the tax effects of timing differences between income for financial reporting purposes and taxable income. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. In accordance with SFAS 109 we recorded a net regulatory asset of $26.9 million and a corresponding net increase in accumulated deferred income taxes as of December 31, 1993. The regulatory asset represents the additional future revenues to be collected from customers for deferred income taxes.

Accumulated deferred income taxes on our consolidated balance sheet at December 31, 1993 includes $587.8 million of gross deferred income tax liabilities net of $103.0 million of gross deferred income tax assets. We have approximately $19 million of alternative minimum tax carryforwards available at December 31, 1993. The major components of accumulated deferred income taxes are a result of differences between book and tax expenses relating to property, plant and equipment.

Deferred income tax expense reflected in our consolidated income statements is incurred when certain income and expenses are reported on the tax return in different years than reported in the financial statements. Investment tax credits are included in income over the estimated useful lives of the related property.

Components of income tax expense are as follows:

(in thousands)	1993	1992	1991
Excess tax depreciation over book depreciation	$12,382	$9,765	$10,802
Deferred fuel expense	(3,142)	2,587	56
Debt portion of allowance for funds used during construction	2,114	2,495	2,856
Massachusetts corporate franchise tax	5,089	6,134	7,140
Deferred nuclear outage expense	2,472	(1,558)	7,014
Cost of removal	3,272	6,904	4,277
Rate and contract settlements	0	10,013	10,196
Municipal property taxes	(489)	3,351	3,745
Demand side management programs	3,775	2,978	2,256
Cancelled nuclear unit	0	(4,621)	(8,998)
Reversal of deferred taxes-settlement agreement, net	(19,231)	(23,000)	(13,000)
Adjustment of prior year income tax accrual	(2,154)	4,134	2,563
Call premiums on refunded bond issues	5,821	1,029	(288)
Trust contributions-postretirement benefits	3,451	0	0
Other	(3,057)	(3,828)	(5,395)
Subtotal deferred income taxes	10,303	16,383	23,224
Current income tax expense	28,711	(385)	(1,823)
Investment tax credits	(4,073)	(4,273)	(4,290)
Provision for income taxes	34,941	11,725	17,111
Taxes on other income:			
Current	1,205	(2,348)	405
Deferred	0	782	1,252
Subtotal	1,205	(1,566)	1,657
Total income tax expense	$36,146	$10,159	$ 18,768

The effective income tax rates reflected in the consolidated financial statements and the reasons for their differences from the statutory federal income tax rate are explained below:

	1993	1992	1991
Statutory tax rate	35.0%	34.0%	34.0%
State income tax, net of federal income tax benefit	4.2	3.9	4.1
Investment tax credits	(2.6)	(3.6)	(3.8)
Municipal property tax adjustment	(0.6)	(1.6)	(1.6)
Adjustment of deferred taxes on cancelled nuclear unit	-	2.7	-
Reversal of deferred taxes-settlement agreement	(13.0)	(19.6)	(11.5)
Federal tax benefit of mandated payments from settlement agreements	-	(6.2)	(3.3)
Other	0.4	(0.9)	(1.4)
Effective tax rate	23.4%	8.7%	16.5%

Note D. Estimated Future Costs of Disposing of Spent Nuclear Fuel and Retiring Nuclear Generating Plants

The existing fuel storage facility at Pilgrim Station includes sufficient room for spent nuclear fuel generated through early 1995. We have a request for a license amendment pending before the Nuclear Regulatory Commission (NRC) to allow modification of the storage facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012. The NRC is reviewing our request and we expect approval in 1994. At that time we will initially modify the facility to provide spent fuel storage capacity through approximately 2003. It is the ultimate responsibility of the United States Department of Energy (DOE) to permanently dispose of spent nuclear fuel as required by the Nuclear Waste Policy Act of 1982. We currently pay a fee of $1.00 per net megawatthour sold from Pilgrim Station generation under a nuclear fuel disposal contract with the DOE. The fee is collected from customers through fuel charges.

When Pilgrim Station's operating license expires in 2012 we will be required to decommission the plant. During rate proceedings we provided our regulators a 1991 study documenting a cost of $328 million to decommission the plant. The study is based on the "green field" method of decommissioning, which provides for the plant site to be completely restored to its original state. We are expensing these estimated decommissioning costs over Pilgrim's expected service life. The 1993 expense of approximately $13 million is included in depreciation expense on the consolidated income statements. We receive recovery of this expense from charges to our retail customers and from other utility companies and municipalities who purchase a contracted amount of Pilgrim's electric generation. The funds we collect from decommissioning charges are deposited in an external trust and are restricted so that they may only be used for decommissioning and related expenses. The net earnings on the trust funds, which are also restricted, increase the nuclear decommissioning fund balance and nuclear decommissioning reserve, thus reducing the amount to be collected from customers. The 1991 decommissioning study has been partially updated for internal planning purposes to evaluate the potential financial impact of long-term spent fuel storage options resulting from delays in DOE spent fuel removal on the estimated decommissioning cost. The partial update indicates an estimated decommissioning cost of approximately $400 million in 1991 dollars based upon a revised spent fuel removal schedule and utilization of dry spent fuel storage technology. We will continue to monitor DOE spent fuel removal schedules and developments in spent fuel storage technology along with their impact on the decommissioning estimate.

We are also an investor in two other domestic nuclear units. Both of these units receive through the rates charged to their customers an amount to cover the estimated cost to dispose of their spent nuclear fuel and to retire the units at the end of their useful lives.

We presently dispose of low-level radioactive waste (LLW) generated at Pilgrim Station at licensed disposal facilities in Barnwell, South Carolina. As a result of developments which have occurred pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, our continued access to such disposal facilities has become severely limited and significantly increased in cost. We have access to the South Carolina site through July 1994, but do not presently believe that disposal site access will be provided after that date. Although legislation has been enacted in Massachusetts establishing a regulatory method for managing the state's LLW including the possible siting, licensing and construction of a LLW disposal facility within the state, it appears unlikely that such a facility will be constructed in a timely manner. Pending the construction of a disposal facility within the state or the adoption by the state of some other LLW management method, we continue to monitor the situation and are investigating other available options, including the possibility of on-site storage.

Note E. Cancelled Nuclear Unit

In May 1982 we began to expense the cost of our cancelled Pilgrim 2 nuclear unit over approximately eleven and one-half years in accordance with an order received from state regulators. We did not expense any of these costs in 1993. Instead, the remaining balance of approximately $19 million at December 31, 1993 and 1992 will be expensed in 1994 and/or 1995 as approved by our state regulators in our 1992 settlement agreement.

Note F. Capital Stock and Indebtedness

Capital Stock

(dollars in thousands, except per share amounts)				1993	1992	December 31, 1991
Common stock equity:						
Common stock, par value $1 per share, 100,000,000 shares authorized; 45,129,227, 44,763,055 and 42,047,356 shares issued and outstanding				$ 45,129	$ 44,763	$ 42,047
Premium on common stock				612,653	602,196	536,567
Retained earnings				218,292	192,948	174,477
Surplus invested in plant				405	405	405
Total common stock equity				$876,479	$840,312	$753,496
Cumulative preferred stock:						
Par value $100 per share, 2,410,000 shares currently authorized; issued and outstanding:						
Non-mandatory redeemable series:						
	Series	Current Shares Outstanding	Redemption Price/Share			
	4.25%	180,000	$103.625	$ 18,000	$ 18,000	$ 18,000
	4.78%	250,000	$102.800	25,000	25,000	25,000
	7.75%	400,000	-	40,000	0	0
	8.25%	400,000	-	40,000	40,000	0
	8.88%	0	-	0	40,000	40,000
Total non-mandatory redeemable series				$123,000	$123,000	$ 83,000
Mandatory redeemable series:						
	Series	Current Shares Outstanding				
	7.27%	480,000		$ 48,000	$ 48,000	$ 50,000
	8.00%	500,000		50,000	50,000	50,000
Total mandatory redeemable series				98,000	98,000	100,000
Less: due within one year				2,000	0	0
Total mandatory redeemable series, net				$ 96,000	$ 98,000	$100,000
Cumulative preference stock:						
Par value $1 per share, 8,000,000 shares authorized; none currently issued and outstanding						
Non-mandatory redeemable series:						
$1.46 series				$ 0	$ 0	$ 2,675
Premium on $1.46 series				0	0	35,658
Total preference stock				$ 0	$ 0	$ 38,333

Dividends Declared per Share

	1993	1992	1991
Common stock	$1.715	$1.655	$1.595
Preferred stock:			
4.25% series	$4.253	$4.250	$4.250
4.78% series	4.785	4.780	4.780
7.27% series	7.270	7.270	7.270
7.75% series	5.707	0	0
8.00% series	8.000	8.000	1.337
8.25% series	8.250	5.278	0
8.88% series	2.220	8.880	8.880
Preference stock:			
$1.46 series	$ 0	$0.365	$1.460
Stated rate auction preference stock	0	0	6.900

Indebtedness

(dollars in thousands)			1993	December 31, 1992
Long-term debt:				
First mortgage bonds:				
Series	Interest Rate	Maturity		
I	4.750%	1995	$ 0	$ 25,000
J	6.125%	1997	0	40,000
K	6.875%	1998	0	50,000
L	9.000%	1999	0	50,000
M	9.375%	2000	0	60,000
N	8.125%	2001	0	75,000
S	Variable	2002	25,000	25,000
Q	9.750%	2003	0	59,375
R	10.950%	2004	0	44,250
P	9.250%	2007	0	60,000
U	10.250%	2014	15,000	15,000
W	9.500%	2016	0	135,000
Total first mortgage bonds			40,000	638,625
Less: due within one year			0	6,800
Total first mortgage bonds, net			$ 40,000	$631,825
Sewage facility revenue bonds			$ 36,300	$ 36,300
Less: funds held by trustee			3,803	12,052
Total sewage facility revenue bonds, net			$ 32,497	$ 24,248
Debentures:				
8.875%, due 1995			$ 100,000	$100,000
5.125%, due 1996			100,000	0
5.700%, due 1997			100,000	0
5.950%, due 1998			100,000	0
6.800%, due 2000			65,000	0
6.050%, due 2000			100,000	0
6.800%, due 2003			150,000	0
9.875%, due 2020			100,000	100,000
9.375%, due 2021			125,000	125,000
8.250%, due 2022			60,000	60,000
7.800%, due 2023			200,000	0
Total debentures			$1,200,000	$385,000
Unsecured medium-term notes			$ 0	$ 50,000
Short-term debt:				
Notes payable:				
Bank loans			$ 106,501	$162,500
Commercial paper			97,650	113,000
Total notes payable			$ 204,151	$275,500

1. Common Stock

Since December 31, 1990, we issued the following shares of common stock:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
Balance December 31, 1990	38,998	$194,993	$314,822
Dividend reinvestment plan	449	2,181	6,844
Change in par value of common stock (a)	0	(157,727)	157,727
New issue (b)	2,600	2,600	57,174
Balance December 31, 1991	42,047	42,047	536,567
Dividend reinvestment plan	416	416	9,658
New issue (c)	2,300	2,300	55,971
Balance December 31, 1992	44,763	44,763	602,196
Dividend reinvestment plan (d)	366	366	10,457
Balance December 31, 1993	45,129	$ 45,129	$612,653

(a) In November 1991 our Articles of Organization were amended to increase authorized common stock from 50 million to 100 million shares and reduce the par value from $5 to $1 per common share.

(b) We used the net proceeds of the 1991 common stock issuance to retire $55 million of Series X, 11% first mortgage bonds.

(c) We used the net proceeds of the 1992 common stock issuance to reduce short-term debt.

(d) At December 31, 1993, the remaining authorized common shares reserved for future issuance under the Dividend Reinvestment and Common Stock Purchase Plan were 815,170 shares.

2. Cumulative Non-Mandatory Redeemable Preferred and Preference Stock

In June 1992 we issued 400,000 shares of 8.25% cumulative non-mandatory redeemable preferred stock at par. The stock is redeemable at $100 per share plus accrued dividends beginning in June 1997. These shares were sold in the form of 1.6 million depositary shares, each representing a one-fourth interest in a share of the preferred stock. We used the proceeds of this issue to fully retire the $1.46 series cumulative non-mandatory redeemable preference stock.

In May 1993 we issued 400,000 shares of 7.75% cumulative non-mandatory redeemable preferred stock at par. The stock is redeemable at $100 per share plus accrued dividends beginning in May 1998. These shares were sold in the form of 1.6 million depositary shares, each representing a one-fourth interest in a share of the preferred stock. We used the proceeds of this issue to fully retire the 8.88% series cumulative non-mandatory redeemable preferred stock.

3. Cumulative Mandatory Redeemable Preferred Stock

The 480,000 shares of our 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $104.36. The redemption price declines annually each May to par value in May 2002. In May 1993 the stock became subject to sinking fund requirements to retire 20,000 shares at $100 per share plus accrued dividends each year through May 2002. In 1992 we purchased 20,000 shares at a discount on the open market which satisfied the mandatory sinking fund requirement for May 1993. Beginning in 1993, we have the non-cumulative option each May to redeem additional shares, not to exceed 20,000, for the sinking fund at $100 per share plus accrued dividends.

We are not able to redeem any part of our 500,000 shares of $100 par value 8% series cumulative preferred stock prior to December 2001. The entire series is subject to mandatory redemption in December 2001 at $100 per share, plus accrued dividends.

4. *Long-Term Debt*

Substantially all our property, plant, equipment, materials and supplies are subject to lien under the terms of our Indenture of Trust and First Mortgage dated December 1, 1940, and its supplements. Currently only the outstanding Series S and U first mortgage bonds are subject to the terms of the indenture.

The aggregate principal amounts of our first mortgage bonds, debentures, and sewage facility revenue bonds (including sinking fund requirements) due in 1994 and 1995 are $0 and $100.6 million, respectively, and $101.6 million per year in 1996 through 1998.

Our first mortgage bonds, Series S, adjustable rate due 2002, paid interest at 9.2% per year for the period January 15, 1993 through January 14, 1994. The rate is adjusted annually and is based upon the ten-year constant maturity Treasury rate as published by the Federal Reserve Board. The interest rate for the period January 15, 1994 through January 14, 1995 is 8.2%.

In September 1992 we issued $60 million of 8.25% debentures which mature in September 2022. The debentures are redeemable at prices decreasing from 103.78% of par beginning in September 2002, to 100% of par beginning in September 2012. We used the net proceeds from the sale to reduce short-term debt. In October 1992 we redeemed the remaining balance of $45 million Series X first mortgage bonds.

In February 1993 we issued $65 million of 6.8% debentures due in 2000. We used the proceeds of this issue to reduce short-term debt. These debentures are not redeemable prior to maturity.

In March 1993 we issued $650 million of debentures and used the proceeds to retire ten of twelve outstanding series of first mortgage bonds and reduce short-term debt. The debentures were issued in five separate series with interest rates ranging from 5.125% to 7.8% and maturing between 1996 and 2023. The 5 1/8% debentures due 1996, 5.70% due 1997, 5.95% due 1998 and 6.80% due 2003 are not redeemable prior to maturity. The 7.80% debentures due 2023 are first redeemable in March 2003 at a redemption price of 103.73%. The redemption price decreases annually each March to par value in March 2013. There is no sinking fund requirement for any series of the debentures.

In August 1993 we issued $100 million of 6.05% debentures due in 2000. We used the proceeds from this sale to reduce short-term debt. These debentures are not redeemable prior to maturity and have no sinking fund requirements.

We redeemed $50 million of 9.65% medium-term notes in September 1992 and $50 million of 9.75% medium-term notes in September 1993.

5. *Sewage Facility Revenue Bonds*

In December 1991, Harbor Electric Energy Company (HEEC), a wholly-owned subsidiary, issued $36.3 million of long-term sewage facility revenue bonds. The bonds are tax-exempt, subject to annual mandatory sinking fund redemption requirements and mature in the years 1995-2015. The weighted average interest rate of the bonds is 7.3%. A portion of the proceeds from the bonds was used to retire $21 million of short-term sewage facility revenue bonds at maturity. The remainder of the proceeds, which is on deposit with the trustee, is being used to finance the construction of HEEC's permanent substation located on Deer Island (in Boston

Harbor) and to fund an amount which must remain in reserve with the trustee. If HEEC should have insufficient funds to pay certain costs on a timely basis or be unable to meet certain net worth requirements, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $7 million.

6. Short-Term Debt

We have arrangements with certain banks to provide short-term credit on both a committed and an uncommitted and as available basis. We currently have authority to issue up to $350 million of short-term debt.

We have a $200 million revolving credit agreement with a group of banks. This agreement is intended to provide a standby source of short-term borrowings. Under the terms of this agreement we are required to maintain a common equity ratio of not less than 30% at all times. Commitment fees must be paid on the unused portion of the total agreement amount.

Information regarding our short-term borrowings, comprised of bank loans and commercial paper is as follows:

(thousands of dollars)	1993	1992	1991
Maximum short-term borrowings	$320,000	$314,998	$324,400
Weighted average amount outstanding	$220,149	$233,286	$221,481
Weighted average interest rates, excluding commitment fees	3.4%	4.1%	6.4%

Note G. Fair Value of Securities

The following methods and assumptions were used to estimate the fair value of each class of securities for which it is practicable to estimate the value:

Nuclear decommissioning fund
The fair value of $70.1 million is based on quoted market prices of securities held.

Cash and cash equivalents
The carrying amount of $8.8 million approximates fair value due to the short-term nature of these securities.

Mandatory redeemable cumulative preferred stock, first mortgage bonds, sewage facility revenue bonds and debentures
The fair values of these securities are based upon the quoted market prices of similar issues. Carrying amounts and fair values as of December 31, 1993 are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 98,000	$ 105,935
First mortgage bonds	40,000	44,132
Sewage facility revenue bonds	36,300	40,528
Debentures	1,200,000	1,237,924

Note H. Commitments and Contingencies

1. Capital Commitments

At December 31, 1993, we had estimated contractual obligations for plant and equipment of approximately $71 million.

2. Lease Commitments

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both noncancelable leases and transmission agreements for the years after 1993 are as follows:

(in thousands)	
1994	$ 27,375
1995	23,878
1996	21,299
1997	19,217
1998	17,969
Years thereafter	139,474
Total	$249,212

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. Our total expense for both lease rentals and transmission agreements for 1993, 1992 and 1991 was $30 million, $30 million and $33.5 million, respectively, net of capitalized expenses of $5 million, $5 million, and $4.8 million, respectively.

3. Hydro-Quebec

We have an approximately 11% equity ownership interest in two companies which own and operate transmission facilities to import electricity from the Hydro-Quebec system in Canada, which is included in our consolidated financial statements. As an equity participant we are required to guarantee, in addition to our own share, the total obligations of those participants who do not meet certain credit criteria and are compensated accordingly. At December 31, 1993, our portion of these guarantees was approximately $22 million.

4. Yankee Atomic Electric Company

In February 1992 the Board of Directors of Yankee Atomic Electric Company (Yankee Atomic) decided to permanently discontinue power operation of the Yankee Atomic nuclear generating station and, in time, decommission that facility. We relied on Yankee Atomic for less than one percent of our system capacity. We have a 9.5% stock investment of approximately $2 million in Yankee Atomic.

In 1993 Yankee Atomic received approval from federal regulators to continue to collect its investment and decommissioning costs through July 2000, the period of the plant's operating license. The estimate of our share of Yankee Atomic's investment and costs of decommissioning is approximately $33 million as of December 31, 1993. This estimate is recorded on our consolidated balance sheet as a power contract liability in deferred credits. An offsetting power contract regulatory asset is included in deferred debits as we continue to collect these costs from our customers in accordance with our 1992 settlement agreement.

5. Nuclear Insurance

The federal Price-Anderson Act currently provides $9.4 billion of financial protection for public liability claims and legal costs arising from a single nuclear-related accident. The first $200 million of nuclear liability is covered by commercial insurance. Additional nuclear liability insurance up to approximately $8.8 billion is provided by a retrospective assessment of up to $75.5 million per incident levied on each of the 116 units licensed to operate in the United States, with a maximum assessment of $10 million per reactor per accident in any year. The additional nuclear liability insurance amount may change as new commercial nuclear units are licensed and existing units give up their licenses. In addition to the nuclear liability retrospective assessments, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection, each licensee can be assessed an additional five percent of the maximum retrospective assessment.

We have purchased insurance from Nuclear Electric Insurance Limited (NEIL) to cover some of the costs to purchase replacement power during a prolonged accidental outage at Pilgrim Station and the cost of repair, replacement, decontamination or decommissioning of our utility property resulting from covered incidents at Pilgrim Station. Our maximum potential total assessment for losses which occur during current policy years is approximately $14.6 million under both the replacement power and excess property damage, decontamination and decommissioning policies. All companies insured with NEIL are subject to retroactive assessments if losses are in excess of the total funds available to NEIL. While assessments may also be made for losses in certain prior policy years, we are not aware of any losses in those years which we believe are likely to result in an assessment.

6. Litigation

In March 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel is vigorously defending this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on quarterly earnings.

7. Hazardous Waste

State regulations revised in 1993 require that properties where releases of hazardous materials occurred in the past be further cleaned up according to a timetable developed by the Massachusetts Department of Environmental Protection. We are currently evaluating the potential costs associated with the cleanup of sites where we have been identified as the owner or operator. There are uncertainties associated with these potential costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of certain other multi-party hazardous waste sites in Massachusetts and other states. At the majority of these other sites we are one of many potentially responsible parties and our alleged share of the responsibility is a small percentage. We do not expect any of our potential cleanup liabilities to have a material impact on financial condition, although provisions for cleanup costs could have a material impact on quarterly earnings.

Note I. Pensions, Other Postretirement and Postemployment Benefits

1. Pensions

We have a noncontributory funded retirement plan, with certain features that allow voluntary contributions. Benefits are based upon an employee's years of service and compensation during the last years of employment. Our funding policy is to contribute each year an amount that is not less than the minimum required contribution under federal law or greater than the maximum tax deductible amount. Plan assets are primarily equities, bonds, insurance contracts and real estate.

Net pension cost included the following components:

(in thousands)	1993	1992	1991
Current service cost - benefits earned	$11,734	$10,683	$ 8,567
Interest cost on projected benefit obligation	33,181	32,287	29,817
Actual return on plan assets	(44,470)	(23,281)	(60,873)
Net amortization and deferral	8,528	(13,549)	26,811
Net pension cost(a)	$ 8,973	$ 6,140	$ 4,322

(a) In accordance with an agreement with our state regulators, we deferred our net pension costs in excess of the annual funding amounts and will recover these costs from customers over time. Net pension costs recorded as expense were approximately $5 million in 1993 and $0 in 1992 and 1991.

We used the following assumptions for calculating pension cost:

	1993	1992	1991
Discount rate	8.25%	8.25%	9.00%
Expected long-term rate of return on assets	10.00%	10.00%	10.00%
Compensation increase rate	4.50%	4.50%	4.50%

We changed our discount rate assumption to 7.0% for calculating pension cost effective January 1994.

The plan's funded status at December 31, 1993 and 1992 was as follows:

(in thousands)	1993	1992
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $384,150 and $322,836	$400,895	$339,035
Plan assets at fair value	$394,233	$392,407
Projected obligation for service rendered to date	(509,661)	(418,312)
Projected benefit obligation in excess of plan assets	(115,428)	(25,905)
Unrecognized prior service cost	8,139	8,817
Unrecognized net (gain) loss	75,352	(6,810)
Unrecognized net obligation	9,932	10,866
Net pension liability	$(22,005)	$(13,032)

We used the following assumptions for calculating the plan's year-end funded status:

	1993	1992
Discount rate	7.00%	8.25%
Compensation increase rate	4.50%	4.50%

2. Other Postretirement Benefits

In addition to pension benefits, we also currently provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. Effective January 1993 we adopted Statement of Financial Accounting Standards No. 106, Employer's Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). This requires us to record a liability during the working years of employees for the expected costs of providing their postretirement benefits other than pensions (PBOPs). Prior to 1993 our policy was to record the cost of PBOPs when paid. Our transition obligation on January 1, 1993 was approximately $183 million, which we elected to recognize over 20 years as permitted by SFAS 106. Our total cost of PBOPs under SFAS 106 in 1993 was approximately $28 million, an increase of approximately $18 million over costs incurred under our prior method of accounting for PBOPs. Our 1992 settlement agreement provides us with a phase-in of a portion of the increased costs and allows us to defer the additional costs in excess of the phase-in amounts to the extent that we fund an external trust. In December 1993 we deposited $18 million on a tax deductible basis into external trusts for the payment of PBOPs. Accordingly, in 1993 we recorded an expense of approximately $16 million, reflecting the amount of cost recovery from customers, and deferred approximately $12 million for future recovery. We capitalized approximately 19% of these costs.

Postretirement benefits cost consisted of the following in 1993:

(in thousands)	
Current service cost - benefits earned	$ 4,351
Interest cost on transition obligation	14,286
Amortization of transition obligation	9,151
Net postretirement benefits cost	$27,788

We used an 8.0% weighted average discount rate and 4.5% rate of compensation increase assumption for calculating the transition obligation and the 1993 postretirement benefits cost. Our expected long-term rate of return on assets is 9.0%. We also assumed a 12.5% health care cost trend rate. Effective January 1, 1994 we changed the discount and health care cost trend rates to 7.0% and 9.0%, respectively, in order to more accurately estimate our future benefit payments. The health care cost trend rate is assumed to decrease by one percent each year to 5% in 1998 and years thereafter. Changes in the health care cost trend rate will affect our cost and obligation amounts. For example, a one percent increase in the rate would increase the total service and interest costs in 1993 by approximately 16% and would increase the accumulated obligation at December 31, 1993 by approximately 13%.

The postretirement benefits program's funded status at December 31, 1993 was as follows:

(in thousands)		
Trust assets at fair value		$ 18,016
Accumulated obligation for service rendered to date from:		
Retirees	$(75,216)	
Active employees eligible to retire	(64,880)	
Active employees not eligible to retire	(73,285)	(213,381)
Accumulated benefit obligation in excess of trust assets		(195,365)
Unrecognized loss		21,497
Unrecognized net obligation		173,868
Net postretirement benefits liability		$ 0

The trust assets consist of money market funds at December 31, 1993.

3. Postemployment Benefits

Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits, will be effective for the first quarter of 1994. This statement will require us to record a liability computed on an actuarial basis for the estimated cost of providing postemployment benefits. Postemployment benefits provided to former or inactive employees, their beneficiaries and covered dependents include salary continuation, severance benefits, disability-related benefits (including workers' compensation), job training and counseling and continuation of health care and life insurance coverage. We currently recognize the cost of these benefits primarily as claims are paid. We do not anticipate a material effect on net income from adopting this statement.

Note J. New Accounting Pronouncement

We will adopt Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities, in the first quarter of 1994. This statement may require us to classify the investments in our nuclear decommissioning fund on our consolidated balance sheet based on how long we intend to hold the individual securities. These investments may be classified as "available for sale" and we may also be required to report any unrealized gains and losses on the investments as a separate component of shareholders' equity. We do not expect the adoption of this statement to have a material effect on shareholders' equity.

Note K. Long-Term Power Contracts

1. Long-Term Contracts for the Purchase of Electricity

We purchase electric power under several long-term contracts for which we pay a share of the generating unit's capital and fixed operating costs through the contract expiration date. The total cost of these contracts is included in purchased power expense in our consolidated income statements. Information relating to these contracts as of December 31, 1993 is as follows:

				proportionate share (in thousands)		
Contract	Contract Expiration Date	Units of Capacity Purchased(a) %	MW	1993 Minimum Debt Service	1993 Interest Portion of Minimum Debt Service	Debt Outstanding Through Cont. Exp. Date
Canal Unit 1	2001	25.0	142	$ 781	$ 314	$ 2,118
Mass. Bay Transportation Authority	2005	100.0	35	(b)	(b)	(b)
Connecticut Yankee Atomic	2007	9.5	56	2,579	1,670	15,898
Ocean State Power - Unit 1	2010	23.5	65	5,323	3,948	22,747
Ocean State Power - Unit 2	2011	23.5	65	4,422	3,376	19,401
Northeast Energy Associates	(c)	(c)	219	(c)	(c)	(c)
L'Energia	2013	73.0	64	(d)	(d)	(d)
Total			646	$13,105	$9,308	$60,164

(a) The Northeast Energy Associates contract represents 6.4% of our total system generation capability. The remaining units listed above represent 12.6% in total.

(b) We are required to pay the greater of $22.00 per kilowatt-year or 90% of the New England Power Pool capability responsibility adjustment charge up to $63.00 per kilowatt-year times the qualified capacity (currently rated at 33.6MW) plus incremental operating, maintenance and fuel costs. The total charges for this contract in 1993 were approximately $2 million.

(c) We purchase approximately 75.5% of the energy output of this unit under two contracts. One contract represents 135MW and expires in the year 2015. The other contract is for 84MW and expires in 2010. We pay for this energy based on a price per kWh actually received. We do not pay a proportionate share of the unit's capital and fixed operating costs. The total charges for these contracts in 1993 were approximately $116 million.

(d) The L'Energia contract started in March 1993. We purchase 73% of the energy output of this unit. We pay for this energy based on a price per kWh actually received. The total charges under this contract for 1993 were approximately $15 million.

Our total fixed and variable costs for these contracts in 1993, 1992 and 1991 were approximately $225 million, $217 million and $154 million, respectively. Our minimum fixed payments under these contracts for the years after 1993 are as follows:

(in thousands)	
1994	$ 69,432
1995	72,418
1996	75,376
1997	71,147
1998	72,429
Years thereafter	725,236
Total	$1,086,038
Total present value	$ 558,600

2. *Long-Term Power Sales*

In addition to our power sales to four wholesale customers, we sell a percentage of Pilgrim Station's output to other utilities under long-term contracts. Information relating to these contracts is as follows:

Contract Customer	Contract Expiration Date	Units of Capacity Sold %	Units of Capacity Sold MW
Commonwealth Electric Company	2012	11.0	73.7
Montaup Electric Company	2012	11.0	73.7
Various municipalities	2000(a)	3.7	25.0
Total		25.7	172.4

(a) Subject to certain adjustments.

Under these contracts, the utilities pay their proportional share of the costs of operating Pilgrim Station and associated transmission facilities. These costs include operation and maintenance expenses, insurance, local taxes, depreciation, decommissioning and a return on capital.

Selected Consolidated Quarterly Financial Data (Unaudited)

(in thousands, except earnings per share)

	Operating Revenues	Operating Income	Net Income	Balance Available for Common Stock	Earnings Per Share of Common Stock (a)
1993					
First quarter	$354,752	$ 41,721	$15,452	$11,377	$0.25
Second quarter	346,074	49,282	22,829	19,125	0.43
Third quarter	436,024	96,319	70,015	66,052	1.47
Fourth quarter	345,403	37,997	9,922	5,959	0.13
1992					
First quarter	$343,505	$ 41,930	$13,816	$ 9,553	$0.23
Second quarter	300,566	32,629	4,953	852	0.02
Third quarter	408,255	100,890	73,698	69,593	1.60
Fourth quarter	359,427	45,451	14,831	10,750	0.24

(a) Based upon the weighted average number of common shares outstanding during the quarter.

Electricity sales and revenues are seasonal in nature, with both being lower in the spring and fall seasons. Quarterly earnings for 1993 reflect a change in the months for which certain customers were billed at higher rates as mandated by the DPU. These customers were billed at these higher rates in July through October in 1992 and in June through September in 1993. The change in billing increased second quarter earnings and reduced fourth quarter earnings by approximately $0.23 per share in 1993.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

(a) Identification of Directors

See "Election of Directors - Information about Nominees and Incumbent Directors" on pages 1 through 4 of the definitive Proxy Statement dated March 17, 1994 incorporated herein by reference.

(b) Identification of Executive Officers

The information required by this item is included at the end of Part I of this Form 10-K under the caption Executive Officers of the Registrant.

(c) Identification of Certain Significant Employees

Not applicable.

(d Family Relationships

Not applicable.

(e) Business Experience

For information relating to the business experience during the past five years and other directorships (of companies subject to certain SEC requirements) held by each person nominated to be a director, see "Election of Directors - Information about Nominees and Incumbent Directors" on pages 1 through 4 of the definitive Proxy Statement dated March 17, 1994, incorporated herein by reference.

For information relating to the business experience during the past five years of each person who is an executive officer, see Executive Officers of the Registrant in this Form 10-K.

(f) Involvement in Certain Legal Proceedings

Not applicable.

(g) Promoters and Control Persons

Not applicable.

Item 11. Executive Compensation

See "Director and Executive Compensation" on pages 5 through 11 of the definitive Proxy Statement dated March 17, 1994, incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a) Security Ownership of Certain Beneficial Owners

To the knowledge of management, no person owns beneficially more than five percent of the outstanding voting securities of the Company.

(b) Security Ownership of Management

See "Stock Ownership by Directors and Executive Officers" on pages 4 through 5 of the definitive Proxy Statement dated March 17, 1994, incorporated herein by reference.

(c) Changes in Control

Not applicable.

Item 13. Certain Relationships and Related Transactions

Not applicable.

Part IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

All other schedules are omitted since they are not required, not applicable, or contain only information which is otherwise provided in the financial statements or notes in Item 8.

		Exhibit	SEC Docket
Exhibit 3	Articles of Incorporation and By-Laws		
Incorporated herein by reference:			
3.1	Restated Articles of Organization	2(a)4	2-58587
3.1.1	Amendment to Restated Articles of Organization, filed May 5, 1977	2.4	2-64975
3.1.2	Amendment to Restated Articles of Organization, filed May 26, 1978	3.1.2	1-2301 Form 10-K for the year ended December 31, 1991
3.1.3	Amendment to Restated Articles of Organization, filed May 6, 1980	3.1.3	1-2301 Form 10-K for the year ended December 31, 1991
3.1.4	Amendment to Restated Articles of Organization, filed May 4, 1983	3.1	1-2301 Form 10-Q for the quarter ended March 31, 1983
3.1.5	Amendment to Restated Articles of Organization, filed April 28, 1986	3.1	1-2301 Form 10-Q for the quarter ended March 31, 1986
3.1.6	Amendment to Restated Articles of Organization, filed August 27, 1986	3.5	1-2301 Form 10-K for the year ended December 31, 1986
3.1.7	Amendment to Restated Articles of Organization, filed February 19, 1987	3.1	1-2301 Form 10-Q for the quarter ended March 31, 1987
3.1.8	Certificate of Vote of Directors Establishing a Series of a Class of Stock, filed March 9, 1987	4.2	1-2301 Form 10-Q for the quarter ended September 30, 1988

		Exhibit	SEC Docket
3.1.9	Amendment to Restated Articles of Organization, filed May 5, 1987	3.1.8	1-2301 Form 10-K for the year ended December 31, 1987
3.1.10	Amendment to Restated Articles of Organization, filed May 27, 1988	4.1	33-24271 Registration Statement dated September 22, 1988
3.1.11	Certificate of Vote of Directors Establishing a Series of a Class of Stock, filed October 4, 1988	4.3	1-2301 Form 10-Q for the quarter ended September 30, 1988
3.1.12	Amendment to Restated Articles of Organization, filed November 7, 1991	3.1.12	1-2301 Form 10-K for the year ended December 31, 1991
3.1.13	Certificate of Vote of Directors Establishing a Series of a Class of Stock, filed November 26, 1991	3.1.13	1-2301 Form 10-K for the year ended December 31, 1991
3.1.14	Certificate of Vote of Directors Establishing a Series of a Class of Stock, filed June 8, 1992	4.1	1-2301 Form 10-Q for the quarter ended June 30, 1992
3.1.15	Certificate of Vote of Directors Establishing a Series of a Class of Stock, filed April 30, 1993	3.1	1-2301 Form 10-Q for the quarter ended June 30, 1993
3.2	Boston Edison Company Bylaws April 19, 1977, as amended January 22, 1987, January 28, 1988, May 24, 1988 and November 22, 1989	3.1	1-2301 Form 10-Q for the quarter ended June 30, 1990

		Exhibit	SEC Docket
Exhibit 4	Instruments Defining the Rights of Security Holders, Including Indentures		

Incorporated herein by reference:

		Exhibit	SEC Docket
4.1	Indenture of Trust and First Mortgage dated December 1, 1940 with State Street Trust Company	B-2	2-4564
4.1.1	Tenth supplemental indenture dated April 1, 1950	7.5	2-8349
4.1.2	Twelfth supplemental indenture dated November 15, 1951	4.2	2-80748
4.1.3	Twenty-fourth supplemental indenture dated June 1, 1962	4.1.3	1-2301 Form 10-K for the year ended December 31, 1990
4.1.4	Twenty-seventh supplemental indenture dated November 1, 1965	4.1.4	1-2301 Form 10-K for the year ended December 31, 1990
4.1.5	Twenty-ninth supplemental indenture dated June 1, 1967	4.1.5	1-2301 Form 10-K for the year ended December 31, 1990
4.1.6	Thirtieth supplemental indenture dated November 1, 1968	4.1.6	1-2301 Form 10-K for the year ended December 31, 1990
4.1.7	Thirty-first supplemental indenture dated December 1, 1969	4.1.7	1-2301 Form 10-K for the year ended December 31, 1990
4.1.8	Thirty-second supplemental indenture dated July 1, 1970	4.1.8	1-2301 Form 10-K for the year ended December 31, 1990

		Exhibit	SEC Docket
4.1.9	Thirty-third supplemental indenture dated May 15, 1971	4.1.9	1-2301 Form 10-K for the year ended December 31, 1990
4.1.10	Thirty-fifth supplemental indenture dated April 15, 1977	4.1.10	1-2301 Form 10-K for the year ended December 31, 1989
4.1.11	Thirty-sixth supplemental indenture dated December 15, 1978	4.1.11	1-2301 Form 10-K for the year ended December 31, 1989
4.1.12	Thirty-seventh supplemental indenture dated October 31, 1979	4.1.12	1-2301 Form 10-K for the year ended December 31, 1989
4.1.13	Thirty-eighth supplemental indenture dated January 1, 1982	4.1.13	1-2301 Form 10-K for the year ended December 31, 1991
4.1.14	Thirty-ninth supplemental indenture dated April 15, 1983	4.1	1-2301 Form 10-Q for the quarter ended March 31, 1983
4.1.15	Fortieth supplemental indenture dated April 1, 1984	4.1	1-2301 Form 10-Q for the quarter ended March 31, 1984
4.1.16	Forty-first supplemental indenture dated April 1, 1985	4.1	1-2301 Form 10-Q for the quarter ended March 31, 1985

		Exhibit	SEC Docket
4.1.17	Forty-second supplemental indenture dated July 15, 1986	4.1	1-2301 Form 10-Q for the quarter ended June 30, 1986
4.1.18	Forty-third supplemental indenture dated September 15, 1987	4.1	1-2301 Form 10-Q for the quarter ended September 30, 1987
4.1.19	Medium-Term Notes Series A - Indenture dated September 1, 1988, between Boston Edison Company and Bank of Montreal Trust Company	4.1	1-2301 Form 10-Q for the quarter ended September 30, 1988
4.1.20	First Supplemental Indenture dated June 1, 1990 to Indenture dated September 1, 1988 with Bank of Montreal Trust Company - 9 7/8% debentures due June 1, 2020	4.1	1-2301 Form 8-K dated June 28, 1990
4.1.21	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken December 11, 1990 re 8 7/8% debentures due December 15, 1995	4.1	1-2301 Form 10-Q for the quarter ended March 31, 1991
4.1.22	Indenture of Trust and Agreement among the City of Boston, Massachusetts (acting by and through its Industrial Development Financing Authority) and Harbor Electric Energy Company and Shawmut Bank, N.A., as Trustee, dated November 1, 1991	4.1.26	1-2301 Form 10-K for the year ended December 31, 1991
4.1.23	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken August 5, 1991 re 9 3/8% debentures due August 15, 2021	4.1.27	1-2301 Form 10-K for the year ended December 31, 1991
4.1.24	Revolving Credit Agreement dated February 12, 1993	4.1.24	1-2301 Form 10-K for the year ended December 31, 1992

		Exhibit	SEC Docket
4.1.25	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken September 10, 1992 re 8 1/4% debentures due September 15, 2022	4.1.25	1-2301 Form 10-K for the year ended December 31, 1992
4.1.26	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken January 27, 1993 re 6.8% debentures due February 1, 2000	4.1.26	1-2301 Form 10-K for the year ended December 31, 1992
4.1.27	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken March 5,1993 re 5 1/8% debentures due March 15, 1996, 5.70% debentures due March 15, 1997, 5.95% debentures due March 15, 1998, 6.80% debentures due March 15, 2003, 7.80% debentures due March 15, 2023	4.1.27	1-2301 Form 10-K for the year ended December 31, 1992

Filed herewith:

4.1.28	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken August 18, 1993 re 6.05% debentures due August 15, 2000	--	--

Exhibit 10 Material Contracts

Executive Compensation:

Incorporated herein by reference:

10.1	Key Executive Benefit Plan (1982 Form of Agreement)	10.13	1-2301 Form 10-K for the year ended December 31, 1992
10.1.1	Amendment to Key Executive Benefit Plan dated February 1, 1986	10.4.1	1-2301 Form 10-K for the year ended December 31, 1985
10.1.2	Key Executive Benefit Plan Standard Form of Agreement, May 1986	10.1	1-2301 for the quarter ended June 30, 1986

		Exhibit	SEC Docket
10.1.3	Key Executive Benefit Plan Standard Form of Agreement, May 1986, with modifications, applicable to Bernard W. Reznicek, George W. Davis and Thomas J. May	10.3.1	1-2301 Form 10-K for the year ended December 31, 1991
10.2	Executive Annual Incentive Compensation Plan	10.5	1-2301 Form 10-K for the year ended December 31, 1988
10.3	Performance Share Plan	10.1	1-2301 Form 10-Q for the quarter ended September 30, 1991
10.4	1991 Director Stock Plan	10.1	1-2301 Form 10-Q for the quarter ended March 31, 1991
10.5	Boston Edison Company Deferred Fee Plan dated January 1, 1990	10.11	1-2301 Form 10-K for the year ended December 31, 1992
10.6	Boston Edison Company Deferred Compensation Plan dated January 1, 1990	10.12	1-2301 Form 10-K for the year ended December 31, 1992
10.7	Deferred Compensation Trust between Boston Edison Company and State Street Bank and Trust Company dated February 2, 1993	10.10	1-2301 Form 10-K for the year ended December 31, 1992
10.8	Description of Supplemental Fee Arrangement for Certain Directors	10.5	1-2301 Form 10-K for the year ended December 31, 1983

Filed herewith:

10.8.1	Directors Retirement Benefit (1993 Plan)	--	--

		Exhibit	SEC Docket
Exhibit 18	Letter re Change in Accounting Principle		
	Incorporated herein by reference:		
18.1	Letter of Independent Certified Public Accountants	18.1	1-2301 Form 10-Q for the quarter ended March 31, 1990
Exhibit 21	Subsidiaries of the Registrant		
21.1	Harbor Electric Energy Company (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Edison Company		
21.2	Boston Energy Technology Group, Inc. (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Edison Company		
21.3	Ener-G-Vision, Inc. (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Energy Technology Group, Inc.		
21.4	TravElectric Services Corporation (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Energy Technology Group, Inc.		
21.5	REZ-TEK International Corporation (incorporated in Massachusetts), a majority-owned subsidiary of Boston Energy Technology Group, Inc.		

		Exhibit	SEC Docket
Exhibit 23	Consent of Independent Accountants		
Filed herewith:			
23.1	Consent of Independent Accountants to incorporate, by reference, their opinion included with this Form 10-K, in the Form S-3 Registration Statements filed by the Company on September 14, 1990 (File No. 33-36824), February 3, 1993 (File No. 33-57840) and in the Form S-8 Registration Statements filed by the Company on October 10, 1985 (File No. 33-00810) July 28, 1986 (File No. 33-7558), December 31, 1990 (File No. 33-38434), June 5, 1992 (33-48424 and 33-48425) and March 17, 1993 (33-59662 and 33-59682).		
Exhibit 99	Additional Exhibits		
Incorporated herein by reference:			
99.1	DPU Settlement Agreement with Boston Edison Company dated October 3, 1989	28.1	1-2301 Form 8-K dated October 3, 1989
99.2	Settlement Agreement between Boston Edison Company and Commonwealth Electric Company, Montaup Electric Company and the Municipal Light Department of the Town of Reading, Massachusetts, dated January 5, 1990	28.1	1-2301 Form 8-K dated December 21, 1989
99.3	Pilgrim Outage Case Settlement between Boston Edison Company and Reading Municipal Light Department regarding Contract Demand Rate, dated December 21, 1989	28.2	1-2301 Form 8-K dated December 21, 1989
99.4	Settlement Agreement Between Boston Edison Company and City of Holyoke Gas and Electric Department et. al., dated April 26, 1990	28.2	1-2301 Form 10-Q for the quarter ended March 31, 1990

		Exhibit	SEC Docket
99.5	Information required by SEC Form 11-K for certain Company employee benefit plans for the years ended December 31, 1992, 1991 and 1990.	-	1-2301 Form 8 Amendments to Form 10-K for the years ended December 31, 1992, 1991 and 1990 dated June 29, 1993, June 26, 1992 and June 28, 1991, respectively
99.6	DPU Settlement Agreement with Boston Edison Company, dated October 23, 1992	28.2	1-2301 Form 10-Q for the quarter ended September 30, 1992

(b) Reports on Form 8-K

A Form 8-K dated October 28, 1993 was filed with the Securities and Exchange Commission by the Company. This report announced the Company's earnings for the three and twelve months ended September 30, 1993.

A Form 8-K dated January 27, 1994 was filed with the Securities and Exchange Commission by the Company. This report contained a press release announcing the Company's earnings for the twelve and three months ended December 31, 1993.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BOSTON EDISON COMPANY

By /s/ Charles E. Peters, Jr.
Charles E. Peters, Jr.
Senior Vice President - Finance
(Principal Financial Officer)

Date: March 24, 1994

Pursuant to the requirements of the Securities Exchange Act of 1934 this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 24th day of March 1994.

/s/ Bernard W. Reznicek Bernard W. Reznicek	Chairman of the Board and Chief Executive Officer
/s/ Thomas J. May Thomas J. May	President and Chief Operating Officer and Director
/s/ George W. Davis George W. Davis	Executive Vice President and Director
/s/ Robert J. Weafer, Jr. Robert J. Weafer, Jr.	Vice President, Controller and Chief Accounting Officer
/s/ William F. Connell William F. Connell	Director
/s/ Gary L. Countryman Gary L. Countryman	Director
______________________ Thomas G. Dignan, Jr.	Director

/s/ Charles K. Gifford Charles K. Gifford	Director
/s/ Nelson S. Gifford Nelson S. Gifford	Director
/s/ Kenneth I. Guscott Kenneth I. Guscott	Director
/s/ Matina S. Horner Matina S. Horner	Director
/s/ Sherry H. Penney Sherry H. Penney	Director
/s/ Herbert Roth, Jr. Herbert Roth, Jr.	Director
______________________ Stephen J. Sweeney	Director
/s/ Paul E. Tsongas Paul E. Tsongas	Director
/s/ Charles A. Zraket Charles A. Zraket	Director

Report of Independent Accountants

To the Stockholders and Directors of Boston Edison Company:

We have audited the consolidated financial statements and the financial statement schedules of Boston Edison Company and subsidiaries (the Company) listed in Item 14(a) of this Form 10-K. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 1993 and 1992, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles. In addition, in our opinion, the consolidated financial statement schedules referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information required to be included therein.

COOPERS & LYBRAND

Boston, Massachusetts
January 25, 1994

Exhibit 4.1.28

Pricing Committee Meeting
Boston, August 18, 1993

A meeting of the Pricing Committee of the Board of Directors of Boston Edison Company was held at the Executive Offices of the Company, 800 Boylston Street, Boston, Massachusetts, on Wednesday, August 18, 1993, at five minutes past twelve o'clock p.m., local time, the Chairman presiding.

Present: Messrs. Reznicek and May - and present and participating by telephone communications equipment, by means of which all persons participating in the meeting could hear each other at the same time, Mr. N. Gifford and Drs. Horner and Penney - and, by invitation, Messrs. Peters, Alpert, Frigard and Conway and Ms. O'Neil.

Absent: None.

Messrs. Reznicek and Peters presented management's proposal to sell $100,000,000 principal amount of debentures. Mr. Reznicek summarized the votes being presented for action by the directors. The directors discussed the matters presented.

On motion duly made and seconded, it was:

Voted: That, pursuant to votes of the Board of Directors adopted on January 28, 1993, the Company issue and sell $100,000,000 aggregate principal amount of unsecured debentures to be issued under and in accordance with the provisions of Article Three of the Indenture dated September 1, 1988 between the Company and Bank of Montreal Trust Company, as Trustee (the "Trustee") as amended and supplemented as of the date hereof (the "Indenture").

Voted: That said series of debentures be established as a separate series of securities in accordance with and pursuant to the Indenture, to be entitled as follows: the 6.05% Debentures due August 15, 2000 (the "Debentures").

Voted: That the Debentures be issued with the following terms:

Maturity Date: August 15, 2000
Interest Rate: 6.05%
Interest Payment Date: February 15 and August 15 of each year commencing February 15, 1994
Price to the Public: 99.935%
Proceeds to the Company: 99.31%
Redemption Provisions: No call

Voted: That the form of the Debentures presented to the Pricing Committee and attached to these votes as Exhibit A is hereby established, adopted and approved with such changes, insertions and omissions as are required or permitted by the Indenture and these votes and that such form shall be filed with the minutes of this meeting; and that the chairman, president, any executive or senior vice president, the treasurer or any assistant treasurer of the Company be, and each of them acting singly is, hereby authorized to complete the form of Debenture as provided for in these votes, the completion of such Debentures to be conclusive evidence that the same has been approved by the Company.

Voted: That the form of Purchase Agreement presented to the Pricing Committee relating to the Debentures is hereby approved and that the chairman, president, any executive or senior vice president, the treasurer and any assistant treasurer be, and each acting singly is, hereby authorized, in the name and on behalf of the Company, to execute with and deliver to Goldman, Sachs & Co. and Salomon Brothers Inc., a Purchase Agreement relating to the Debentures with such changes, insertions and omissions as the officer or officers executing the same may approve, such execution and delivery to be conclusive evidence of the authorization and approval thereof by the Company.

Voted: That Bank of Montreal Trust Company is hereby designated as the transfer agent, registrar and paying agent for the Debentures and that the Trustee and such transfer agent, registrar and paying agent shall be entitled to the estate, powers, rights, authorities, benefits, privileges and immunities set forth in the Indenture; and that such resolutions, if any, as are customarily requested by the Trustee and each such transfer agent, registrar and paying agent with respect to its authority are hereby adopted and shall be filed with the minutes of this meeting.

Voted: That the chairman, president, any executive or senior vice president, the treasurer or any assistant treasurer be, and each of them is, hereby authorized to file with the Trustee a certificate setting forth the form and terms of the Debentures as established by and pursuant to these votes and the written order for the certification and delivery to the purchasers at the time and in the manner specified in the Purchase Agreement for the Debentures; and that the officers of the Company be, and each of them acting singly is, hereby authorized to take such further action and execute such certificates, instruments and other documents as in the judgment of such officers or officer will comply with the provisions of the Indenture and the Purchase Agreement and to issue and deliver the Debentures in accordance therewith.

Voted: That the treasurer or any assistant treasurer be, and each of them acting singly is, hereby authorized and directed to apply the proceeds from the issue and sale of the Debentures to repay obligations incurred under bank lines of credit and commercial paper for capital expenditures for extensions, additions and improvements to the Company's plant and property and for working capital purposes.

Voted: That the officers of the Company are, and each acting singly is, hereby authorized to execute and deliver such other documents and take such further actions in the name of the Company as the officers or officer so acting shall deem advisable to implement the foregoing votes, such execution and delivery or the taking of any such action to be conclusive evidence of its authorization by the Company.

No further business being presented, on motion duly made and seconded, the meeting dissolved at fifteen minutes past twelve o'clock p.m., local time.

A true record.

Attest:

Theodora S. Convisser
Clerk

Exhibit 10.8.1

Directors Retirement Benefit
(1993 Plan)

At its April 6, 1993 meeting, the Executive Committee voted to recommend to the Board of Directors that the Company's retirement benefit for outside directors be amended as follows:

Vesting:	The benefit will vest upon the earlier of (1) the completion of ten years of service on the Board; (2) service on the Board until retirement at the annual meeting of stockholders following a director's seventieth birthday; or (3) death while serving on the Board.
Annual Amount:	The annual amount of the benefit will be equal to the cash component of the annual Board retainer plus two annual Committee member retainers, as those retainers are in effect at the time of a director's retirement or death (currently \$10,000 + \$2,750 + \$2,750 or \$15,500). The annual amount will be paid in quarterly installments.
Duration of Benefit:	A director while living will receive the annual amount for a period of years equal to his or her service on the Board.
Survivor Benefit:	Should a director die prior to full receipt of the benefit, his or her survivors will continue to receive the benefit for a period of time equal to the lesser of (1) the full years-of-service term to which the director would have been entitled if living or (2) a period of ten years from the commencement of payment of the benefit. Survivors may elect to receive the benefit in the form of a lump sum. The lump sum will be equal to the present value of the remaining benefit, calculated with reference to the Pension Benefit Guarantee Corporation rate as in effect at the time of the director's death.
Commencement of Benefit:	Payment of the benefit to a qualified director will commence at the quarterly payment date following the director's departure from the Board and attainment of age 65. Should a qualified director die prior to the commencement of the benefit, payment of the benefit to his or her survivors as described above will commence at the next quarterly payment date following the director's death.
Applicability:	The amended director retirement benefit as proposed herein will take effect for all retirements from the Board occurring in 1993 and thereafter.

Service of Less than a Year:	Service of less than a year will be calculated with reference to the applicable fraction for determining both vesting and benefit duration. Thus, for example, if a director has service equal to six years and nine months when he retires at age 70, he will receive the annual amount for 6 3/4 years.

Exhibit 23.1

Consent of Independent Accountants

We consent to the incorporation by reference in the registration statements of Boston Edison Company on Form S-3 (File Nos. 33-36824 and 33-57840) and on Form S-8 (File Nos. 33-00810, 33-7558, 33-38434, 33-48424, 33-48425, 33-59662 and 33-59682) of our report dated January 25, 1994 on our audits of the consolidated financial statements and financial statement schedules of Boston Edison Company as of December 31, 1993 and 1992 and for each of the three years in the period ended December 31, 1993, which report is included in this Annual Report on Form 10-K.

Boston, Massachusetts
March 30, 1994

COOPERS & LYBRAND

Schedule V

Boston Edison Company
Property, Plant and Equipment
December 31, 1993
(in thousands)

Column A Classification	Column F Balance at end of period
Electric plant:	
Land and rights of way	$ 38,944
Generating station and substation buildings and misc. structures	472,789
Electric generating equipment	1,622,664
Transmission, distribution, street lighting and other utilization equipment	1,720,798
Capitalized DSM	48,625
Total electric plant	3,903,820
Nuclear fuel	273,867
Non-utility property	956
Construction work in progress	144,835
Total	$4,323,478

(1) The information required in columns B, C, D and E is omitted as neither the total additions nor the total retirements during the year exceed 10% of the balance at the end of 1993. Total additions and retirements were $252,770 and $34,147, respectively.

(2) Electric plant was depreciated on a straight-line basis at various rates ranging from 1.80% to 4.03% in 1993. For further information relating to the Company's policies regarding depreciation and amortization, see Note A included in Item 8.

(3) Approximately $92,000 of additions in 1993 relate to various modifications made to the Company's transmission and distribution systems, approximately $73,000 represent an increase in generating equipment, approximately $37 million represent capitalized DSM and the remainder includes additions to generating station and other plant.

Boston Edison Company
Property, Plant and Equipment
December 31, 1992
(in thousands)

Schedule V

Column A Classification	Column F Balance at end of period
Electric plant:	
Land and rights of way	$ 38,488
Generating station and substation buildings and misc. structures	427,780
Electric generating equipment	1,484,509
Transmission, distribution, street lighting and other utilization equipment	1,666,525
Capitalized DSM	11,469
Total electric plant	3,628,771
Nuclear fuel	270,420
Non-utility property	956
Construction work in progress	182,458
Total	$4,082,605

(1) The information required in columns B, C, D and E is omitted as neither the total additions nor the total retirements during the year exceed 10% of the balance at the end of 1992. Total additions and retirements were $244,215 and $34,036, respectively.

(2) Electric plant was depreciated on a straight-line basis at various rates ranging from 2.67% to 4.29% in 1992. For further information relating to the Company's policies regarding depreciation and amortization, see Note A included in Item 8.

(3) Approximately $95,000 of additions in 1992 relate to various modifications made to the Company's transmission and distribution systems, approximately $78,000 represent an increase in generating equipment, approximately $31,000 represent increases in nuclear fuel and the remainder includes additions to generating station and other plant.

Schedule V

Boston Edison Company
Property, Plant and Equipment
December 31, 1991
(in thousands)

Column A Classification	Column F Balance at end of period
Electric plant:	
Land and rights of way	$ 38,495
Generating station and substation buildings and misc. structures	408,249
Electric generating equipment	1,475,395
Transmission, distribution, street lighting and other utilization equipment	1,609,912
Total electric plant	3,532,051
Nuclear fuel	256,199
Non-utility property	956
Construction work in progress	99,870
Total	$3,889,076

(1) The information required in columns B, C, D and E is omitted as neither the total additions nor the total retirements during the year exceed 10% of the balance at the end of 1991. Total additions and retirements were $210,885 and $30,333, respectively.

(2) Electric plant was depreciated on a straight-line basis at various rates ranging from 2.84% to 4.59% in 1991. For further information relating to the Company's policies regarding depreciation and amortization, see Note A included in Item 8.

(3) Approximately $87,000 of additions in 1991 relate to various modifications made to the Company's transmission and distribution systems, approximately $99,000 represent an increase in generating equipment and the remainder includes additions to generating station and other plant.

Boston Edison Company
Accumulated Depreciation, Depletion and
Amortization of Property, Plant and Equipment
1993
(in thousands)

Schedule VI

Column A	Column B	Column C	Column D	Column E	Column F
Description	Balance at beginning of period	Additions Charged to Costs and Expenses	Retirements	Other Changes	Balance at end of period
Depreciation reserve:					
Electric plant:					
Production-fossil	$ 275,749	$ 25,981	$17,619	$ 182	$ 284,293
-nuclear	352,997	43,184(A)	2,883	0	393,298
-other	18,884	1,089	579	100	19,494
Total production	647,630	70,254	21,081	282	697,085
Transmission	129,710	6,627	289	46	136,094
Distribution	339,153	29,727	17,863	2,428	353,445
General	58,490	15,584(B)	12,608	65	61,531
Capitalized DSM	0	6,968	0	0	6,968
Harbor Electric Energy Company	2,311	925	0	0	3,236
Total electric	1,177,294	130,085	51,841	2,821(D)	1,258,359
Accumulated amortization of nuclear fuel (F)	201,978	21,815	0	(3,316)(E)	220,477
Total	$1,379,272	$151,900	$51,841(C)	$ (495)	$1,478,836

(A) Excludes $12,865 of nuclear decommissioning costs.
(B) Includes $9,237 of amortization of leasehold improvements, computer software and load management program costs.
(C) Includes $17,694 of removal costs.
(D) Includes salvage value of property retired of $2,568 and FERC audit adjustments from audit report covering the period 1/1/87 - 12/31/90 of $253.
(E) Payments to the Department of Energy for post-April 1983 nuclear fuel disposal.
(F) For information regarding the amortization policy for nuclear fuel, see Note A, part 4, to the consolidated financial statements included in Item 8.

Boston Edison Company
Accumulated Depreciation, Depletion and
Amortization of Property, Plant and Equipment
1992
(in thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Description	Balance at beginning of period	Additions Charged to Costs and Expenses	Retirements	Other Changes	Balance at end of period
Depreciation reserve:					
Electric plant:					
Production-fossil	$ 268,744	$ 26,106	$19,141	$ 40	$ 275,749
-nuclear	313,870	39,948(A)	1,209	388	352,997
-other	18,499	1,713	1,978	650	18,884
Total production	601,113	67,767	22,328	1,078	647,630
Transmission	120,533	9,770	628	35	129,710
Distribution	323,178	34,362	19,919	1,532	339,153
General	51,795	10,416(B)	3,723	2	58,490
Harbor Electric Energy Company	1,372	939	0	0	2,311
Total electric	1,097,991	123,254	46,598	2,647(D)	1,177,294
Accumulated amortization of nuclear fuel (F)	180,137	25,473	0	(3,632)(E)	201,978
Total	$1,278,128	$148,727	$46,598(C)	$ (985)	$1,379,272

(A) Excludes $5,575 of nuclear decommissioning costs.
(B) Includes $5,976 of amortization of leasehold improvements, computer software and load management program costs.
(C) Includes $12,562 of removal costs.
(D) Represents salvage value of property retired.
(E) Payments to the Department of Energy for post-April 1983 nuclear fuel disposal.
(F) For information regarding the amortization policy for nuclear fuel, see Note A, part 4, to the consolidated financial statements included in Item 8.

Boston Edison Company
Accumulated Depreciation, Depletion and
Amortization of Property, Plant and Equipment
1991
(in thousands)

Schedule VI

Column A	Column B	Column C	Column D	Column E	Column F
Description	Balance at beginning of period	Additions Charged to Costs and Expenses	Retirements	Other Changes	Balance at end of period
Depreciation reserve:					
Electric plant:					
Production-fossil	$ 254,402	$ 24,989	$10,790	$ 143	$ 268,744
-nuclear	276,126	38,109(A)	365	0	313,870
-other	16,713	1,788	2	0	18,499
Total production	547,241	64,886	11,157	143	601,113
Transmission	110,369	10,308	148	4	120,533
Distribution	312,855	33,711	25,112	1,724	323,178
General	44,444	10,238(B)	2,889	2	51,795
Harbor Electric Energy Company	462	910	0	0	1,372
Total electric	1,015,371	120,053	39,306	1,873(D)	1,097,991
Accumulated amortization of nuclear fuel (F)	163,694	19,869	0	(3,426)(E)	180,137
Total	$1,179,065	$139,922	$39,306(C)	$(1,553)	$1,278,128

(A) Excludes $4,675 of nuclear decommissioning costs.
(B) Includes $6,179 of amortization of leasehold improvements, computer software and load management program costs.
(C) Includes $8,974 of removal costs.
(D) Represents salvage value of property retired.
(E) Payments to the Department of Energy for post-April 1983 nuclear fuel disposal.
(F) For information regarding the amortization policy for nuclear fuel, see Note A, part 4, to the consolidated financial statements included in Item 8.

Guarantees of Securities of Other Issuers
December 31, 1993
(in thousands)

Column A	Column B	Column C	Column D	Column E	Column F	Column G
Name of issuer of securities	Title of issue	Total amount guaranteed and outstanding	Amount owned by Company	Amount in treasury of issuer of securities guaranteed	Nature of guarantee	Nature of default by issuer
Yankee Atomic Electric Company:	$40 Million Amortizing Term Loan - expires 1997	$ 1,300	none	none	guarantee of principal and interest	none
New England Hydro Finance Company, Inc.: (1)	Series A Note - due 2001	$10,000	none	none	guarantee of principal and interest	none
	Series B Note - due 2007	6,300				
	Series C Note - due 2015	5,700				
	Total	$22,000				

(1) As part of Hydro-Quebec Phase II, the Company and other New England electric utilities became equity owners in New England Hydro-Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation, the parent companies and guarantors of New England Hydro Finance Company, Inc. The Company and other equity participants agreed to guarantee severally their proportionate share of the borrowings outstanding of these companies pursuant to the Note and Guarantee Agreement dated April 15, 1991. The Company and other equity participants also guarantee their proportionate share of the total obligations of the participants who do not meet certain credit criteria.

Boston Edison Company
Short-Term Borrowings
Year ended December 31,
(in thousands)

Schedule IX

	Column A	Column B	Column C	Column D	Column E	Column F
	Category of aggregate short-term borrowings	Balance at end of period	December 31 weighted average interest rate	Maximum amount outstanding during the period	Average amount outstanding during the period	Weighted average interest rate during the period
1993	(1)	$204,151	3.5%	$320,000	$220,149	3.4%
1992	(1)	$275,500	3.8%	$314,998	$233,286	4.1%
1991	(1)	$210,300	6.1%	$324,400	$221,481	6.4%

(1) Borrowings under:

	Year ended December 31,		
	1993	1992	1991
Lines of credit	$106,501	$162,500	$ 89,000
Commercial paper	97,650	113,000	121,300
Total	$204,151	$275,500	$210,300

For information regarding the Company's borrowing arrangements, see Note F, part 6, to the consolidated financial statements included in Item 8.

Boston Edison Company
Supplementary Income Statement Information
Year ended December 31,
(in thousands)

Schedule X

Column A	Column B		
	Charged to costs and expenses		
Item	1993	1992	1991
Maintenance and repairs*	$94,826	$87,113	$102,215
Taxes other than payroll and income taxes:			
Municipal property	$77,238	$63,430	$ 51,486

* Amounts are net of capitalized expenses.

For amortization of deferred cost of cancelled nuclear unit and amortization of deferred nuclear outage costs, see the consolidated statements of income included in Item 8.